2015 Ozone NAAQS Attainment Plan for the Las Vegas Valley Moderate Nonattainment Area

November 5, 2024

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EXECUTIVE SUMMARY

The Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ) hereby submits this *2015 Ozone NAAQS Attainment Plan for the Las Vegas Valley Moderate Nonattainment Area* (attainment plan) to the U.S. Environmental Protection Agency (EPA) to fulfill its State Implementation Plan (SIP) requirements for the 2015 8-hour ozone National Ambient Air Quality Standard (NAAQS) related to the Hydrographic Area (HA) 212 moderate nonattainment area. The attainment plan demonstrates that the modeled ozone design value for HA 212 will be below the NAAQS by the attainment date. It includes such required attainment plan elements as an emissions inventory; an attainment modeling demonstration; and Reasonably Available Control Technology (RACT), Reasonably Available Control Measures (RACM), and 15% Rate-of-Progress (ROP) analyses, among other information.

This attainment plan uses the most recently adopted planning variables (e.g., vehicle miles traveled projections and population forecasts) approved by the designated Metropolitan Planning Organization for the Las Vegas urban area, the Regional Transportation Commission of Southern Nevada, and establishes a motor vehicle emissions budget (MVEB). Once approved, the Regional Transportation Commission of Southern Nevada will use the MVEB for transportation conformity determinations in future regional transportation plans.

As part of this attainment plan submission, DAQ certifies that certain existing Clark County Air Quality Regulations (AQRs) meet RACT requirements, Inspection and Maintenance (I/M) Program requirements, and Nonattainment Major New Source Review SIP requirements; submits new regulations to meet RACT, ROP, and contingency measure requirements; and replaces some existing SIP-approved rules with new ones to improve rule effectiveness by promoting consistency and thoroughness in compliance obligations. The included contingency plan sets forth a control measure that applies only if EPA finds HA 212 did not reach attainment by the moderate area attainment date (August 3, 2024).

The complete attainment plan submission will turn off EPA's SIP sanction clock. After EPA approval, the attainment plan and the AQRs included in this submission will become federally enforceable by EPA.

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ACRONYMS AND ABBREVIATIONS

Acronyms

Act	Clean Air Act of 1970 and amendments
AIM	architectural and industrial maintenance
AQRs	Clark County Air Quality Regulations
AQS	Air Quality System (EPA)
BACT	best available control technology
BCC	Clark County Board of County Commissioners
BEIS	Biogenic Emissions Inventory System
BELD	Biogenic Emissions Landuse Database
CAA	Clean Air Act
CAMx	Comprehensive Air Quality Model
CARB	California Air Resources Board
CFR	Code of Federal Regulations
CGS	Clark Generating Station
CI	compression ignition
CO SIP	*Carbon Monoxide State Implementation Plan: Las Vegas Valley Nonattainment Area, Clark County, Nevada*
CTG	Control Technique Guideline
DAQ	Division of Air Quality
DES	Department of Environment and Sustainability
DLNC	dry-low NO_x combustion
DMV	Department of Motor Vehicles (Nevada)
DOA	Clark County Department of Aviation
ECS	emissions control system
EMP	Emissions Modeling Platform
EPA	U.S. Environmental Protection Agency
ERC	Emissions Reduction Credit
EVR	enhanced vapor recovery
FR	*Federal Register*
GCP	good combustion practices
GDF	gasoline dispensing facility
GHG	greenhouse gas
GMP	good maintenance practices
GVWR	(manufacturer’s) gross weight rating
HA	hydrographic area
HAP	hazardous air pollutant
I/M	inspection and maintenance
LAER	lowest achievable emissions rate
LNB	low NO_x burner
LNO_x	low NO_x
LVT	Las Vegas Terminal
MEGAN3.2	Model of Emissions of Gases and Aerosols from Nature (version 3.2)
MGMRI	MGM Resorts International
MMBtu/hr	Millions of British thermal units per hour

MOVES	Motor Vehicle Emissions Simulator
MVEB	motor vehicle emissions budget
NAAQS	National Ambient Air Quality Standards
NAFB	Nellis Air Force Base
NDEP	Nevada Division of Environmental Protection
NEI	National Emissions Inventory
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NNSR	Nonattainment New Source Review (major sources)
NRS	Nevada Revised Statutes
NSPS	New Source Performance Standard
NSR	New Source Review
OTC	Ozone Transport Commission
OYW	one year's worth
PSM	Performance Standard Modeling
PTE	potential to emit
RACM	reasonably available control measure
RACT	reasonably available control technology
RFP	Reasonable Further Progress
RICE	reciprocating internal combustion engine
ROP	Rate-of-Progress (plan)
SCC	Source Classification Code
SCR	selective catalytic reduction
SENS1-6	sensitivity tests 1–6
SIP	State Implementation Plan
SLAMS	State and Local Air Monitoring Stations
SMOKE	Sparse Matrix Operator Kernel Emissions
SPGS	Sun Peak Generating Station
SPM	special purpose monitor
SSM	startup, shutdown, and malfunction
U.S.C.	United States Code
UST	underground storage tank
VCP	volatile chemical products
VOC	volatile organic compound
WRF	Weather Research and Forecasting (model)

Abbreviations

CO	carbon monoxide
g	gram
gal	gallon
hp	horsepower
hp-h	horsepower-hour
L	liter
lb	pound
kN	kilonewtons
m	meter
m^3	cubic meter

mm	millimeter
mmHg	millimeters of mercury
NO_x	oxide(s) of nitrogen
O_2	oxygen
$PM_{2.5}$	particulate matter less than 2.5 micrometers
PM_{10}	particulate matter less than 10 micrometers
ppb	parts per billion
ppm	parts per million
tpd	tons per day
tpy	tons per year

1.0 ATTAINMENT PLAN OVERVIEW

1.1 INTRODUCTION

The Clean Air Act (Act) established a framework of cooperative federalism wherein the U.S. Environmental Protection Agency (EPA) set forth minimum requirements for state air quality programs (Title 42, Section 7410 of the U.S. Code (42 U.S.C. 7410)). Title 40, Part 51 of the Code of Federal Regulations (40 CFR Part 51) requires each state to submit state implementation plans (SIPs) to carry out air pollution control measures required by the Act. One of these SIP requirements is the development of maintenance plans for areas previously designated as being in nonattainment with a National Ambient Air Quality Standard ("NAAQS").

Chapter 445B.500 of the Nevada Revised Statutes (NRS) requires that the board of county commissioners of each county with a population of 100,000 or more establish and implement an air pollution control program. In June 2001, the governor designated the Clark County Board of County Commissioners (BCC) as the air pollution control agency for Clark County and delegated state responsibilities for meeting Clean Air Act requirements, including the development and submittal of SIPs, to the BCC. The BCC formally accepted this designation in July 2001 and delegated air quality responsibilities to the newly formed Department of Air Quality Management, approved by EPA at 40 CFR Part 52.1470. (Between 2001 and 2020, the department also functioned under the names "Department of Air Quality Management (DAQM)," "Department of Air Quality and Environmental Management" (DAQEM), and "Department of Air Quality.")

In 2020, the Department of Air Quality became the Department of Environment and Sustainability (DES), consisting of three divisions: Air Quality, Desert Conservation, and Sustainability. The Division of Air Quality (DAQ) is now responsible for administering the air pollution control program for Clark County under the provisions of the Clark County Air Quality Regulations (AQRs) (Sections 0–94), as adopted in 40 CFR Part 52, Subpart DD.

The mission of DAQ is to develop and implement high-quality, effective local programs to fulfill air quality regulatory requirements and address community concerns, protecting the region's quality of life while facilitating orderly growth. In furtherance of this mission, DAQ prepared this attainment plan to fulfill Clark County's SIP obligations. The attainment plan models Hydrographic Area (HA) 212, the only area in Clark County currently designated nonattainment for the 2015 8-hour ozone NAAQS, as being in attainment by the August 3, 2024, attainment date.

This section provides an overview of ozone health effects and the history of ozone nonattainment in Clark County.

1.2 CHARACTERISTICS AND HEALTH EFFECTS OF OZONE

Ozone is a gas composed of three oxygen atoms that occurs both in the upper atmosphere (stratosphere) and at ground level (troposphere). Ozone in the stratosphere, which extends upward from 6 to 30 miles, occurs naturally, and protects life from harmful ultraviolet rays. Ozone in the troposphere, however, poses a significant health risk, especially for children, the elderly, and people with chronic illnesses. It may also damage crops, trees, and other vegetation.

Ground-level ozone forms through chemical reactions that involve two oxides of nitrogen [nitric oxide and nitrogen dioxide, together referred to as nitrous oxide (NO_x)], volatile organic compounds (VOC), and carbon monoxide (CO) in the presence of sunlight. While all three are ozone precursors, EPA requires ozone attainment plans to address only NO_x and VOC.

Ozone can irritate lung airways and cause an inflammation that resembles sunburn: symptoms include wheezing, coughing, pain when taking a deep breath, and difficulty breathing during exercise or outdoor activities. Children and those with respiratory problems are particularly susceptible, but ozone can affect even healthy people who are active outdoors. Repeated exposure over many months may cause permanent lung damage. Even when concentrations are low, ozone pollution may aggravate asthma, reduce lung capacity, and increase susceptibility to respiratory illnesses like pneumonia and bronchitis.

Ground-level ozone may also affect plants and ecosystems. It can interfere with the ability of plants to produce and store food, which makes them more susceptible to disease, insects, harsh weather, and other pollutants. This in turn can impact crop and forest yields. In addition, ozone can damage the leaves of trees and other plants.

1.3 HISTORY OF THE CLARK COUNTY NONATTAINMENT AREA

Clark County's ozone planning efforts span four EPA NAAQS revisions. EPA's implementation rules, and federal court decisions related to those rules, frequently affected the county's SIP requirements and submittal deadlines.

On March 3, 1978, EPA designated the Las Vegas Valley as a nonattainment area for the 1971 photochemical oxidant NAAQS, as noted in volume 43, page 8962 of the *Federal Register* (43 FR 8962). Air quality monitoring data for 1975–1977 show violations of the 1-hour ozone NAAQS of 0.08 parts per million (ppm).

On February 8, 1979, EPA established a primary 1-hour ozone NAAQS of 0.12 ppm (44 FR 8202) and designated the Las Vegas Valley as a nonattainment area for that standard. The county required industries to implement control technologies to curb precursor pollutants after research demonstrated that industrial processes within Clark County were contributing to elevated ozone levels. By the end of 1984, Clark County had completed a SIP demonstrating attainment of the 1979 ozone NAAQS.

In April 1986, the state requested that EPA redesignate the Las Vegas Valley as an attainment area, and documented the control measures and technologies resulting in compliance with the 1979 ozone NAAQS. EPA approved the 1984 SIP submission in August of that year, and on November 19, 1986, redesignated the Las Vegas Valley as an attainment area for the NAAQS effective January 20, 1987 (51 FR 41788).

Clark County remained in compliance with the 1979 1-hour ozone NAAQS for over a decade. Then, on July 18, 1997 (62 FR 38856), EPA replaced the 1-hour 0.12 ppm standard with an 8-hour 0.08 ppm standard that became effective in September 1997.

On June 27, 2003, Clark County submitted a recommendation to the Nevada Division of Environmental Protection (NDEP) that EPA designate Clark County as an attainment area for the 1997 8-

hour ozone NAAQS, since the preceding three years of data (2000, 2001, and 2002) supported that designation. On July 10, 2003, pursuant to Section 107(d) of the 1990 Clean Air Act Amendments, the governor submitted this recommendation to EPA Region 9. EPA agreed with the submission, but noted it was tracking 2003 ozone monitoring data that indicated Clark County exceeded the NAAQS at one location.

On April 30, 2004—before acting on the governor's recommendation—EPA promulgated an implementation rule for the 1997 8-hour ozone NAAQS (69 FR 23951) related to the Act, Part D, Subparts 1 and 2. Subpart 1 contains general requirements that apply to all nonattainment areas for any NAAQS; Subpart 2 contains requirements specific to ozone classifications based on EPA's 1979 1-hour ozone NAAQS. Under the final rule, EPA would designate nonattainment areas with design values above the 1997 8-hour ozone NAAQS under Subpart 2 based on their current 1-hour ozone design values. If an area's current design value was below the level of the 1979 NAAQS but above that of the 1997 NAAQS, as Clark County's was, EPA would designate that area "basic" nonattainment under Subpart 1.

The day EPA promulgated the implementation rule (April 30, 2004), EPA also designated Clark County as a basic nonattainment area for the 1997 8-hour ozone NAAQS, effective 45 days later (69 FR 23858). EPA based its decision on 2001, 2002, and 2003 monitoring data, which showed the area was not meeting the 1997 8-hour ozone NAAQS. On May 21, 2004, before this designation became effective, Nevada's governor submitted a request to EPA to delay the effective date until October 15, 2004, to provide Clark County time to revise its recommendation. EPA agreed and promulgated a final rule deferring the effective date to September 13, 2004 (69 FR 34076).

EPA further agreed that relevant factors for defining a nonattainment area might support a different recommendation than the one the state submitted on April 12, 2004. On August 2, 2004, the state submitted a revised recommendation to designate only a portion of Clark County as a nonattainment area for the 1997 8-hour ozone NAAQS. The recommendation encompassed:

- Ivanpah Valley (HAs 164A, 164B, 165, and 166)
- Eldorado Valley (HA 167)
- Las Vegas Valley (HA 212)
- Colorado River Valley (HA 213)
- Paiute Valley (HA 214)
- Apex Valley (HAs 216 and 217)
- A portion of the Moapa Valley (HA 218).

EPA accepted the state's recommendations and issued a final rule on September 17, 2004, delineating the revised boundaries with the included HAs (69 FR 55956).

On December 22, 2006, a three-judge panel from the U.S Court of Appeals for the District of Columbia Circuit vacated EPA's Phase 1 Implementation Rule for the 1997 ozone NAAQS (*South Coast Air Quality Management Dist. v. EPA*, 472 F.3d 882 (D.C. Cir. 2006)), including use of the "basic nonattainment" classification under Part D, Subpart 1 of the Act. EPA and other organizations filed petitions for a review of the decision by the entire court. On June 8, 2007, the full court revised the decision by vacating only certain portions of the Phase I rule; however, the vacatur still included the “basic” classification determinations made under Subpart 1 for nonattainment areas like those in Clark County (*South Coast Air Quality Management Dist. v. EPA*, 489 F.3d 1245 (D.C. Cir. 2007)).

Following the D.C. Circuit Court’s decision, EPA issued a memorandum on June 15, 2007, stating that nonattainment areas classified under “Subpart 1 are not currently subject to the June 15, 2007, submission date for their attainment demonstrations” (EPA 2007). EPA required Clark County to develop and submit the *8-Hour Ozone Early Progress Plan for Clark County, Nevada* (DES 2008) to establish motor vehicle emission budgets (MVEBs) for maintaining transportation conformity. The BCC adopted and approved the early progress plan on June 17, 2008. EPA formally approved the MVEBs on May 14, 2009 (74 FR 22738).

On March 29, 2011, EPA determined the Clark County nonattainment area had attained the 1997 8-hour ozone NAAQS based on monitoring data from 2007–2009 (76 FR 17343). DAQEM prepared and submitted a request for EPA to redesignate the area to attainment, along with a 2011 maintenance plan covering the first 10-year period following redesignation (DES 2011). EPA approved the submission and formally redesignated the area as attainment for the 1997 8-hour ozone NAAQS on January 8, 2013 (78 FR 1149).

In 2008, EPA revised the ozone NAAQS to 0.075 ppm, based on an area’s three-year average of the annual fourth-highest daily maximum 8-hour average ozone concentration (73 FR 16436). Although it had not yet redesignated portions of the county to attainment for the 1997 ozone NAAQS, EPA designated all of Clark County as attainment for the 2008 ozone NAAQS (77 FR 30088). EPA called such areas with different designations for the two NAAQS “orphan maintenance areas.”

EPA revoked the 1997 ozone NAAQS in its 2008 ozone implementation rule and removed the requirement that orphan maintenance areas, such as Clark County, submit a second 10-year maintenance plan (40 CFR Part 51.1105(d) (vacated)). Therefore, Clark County no longer needed to comply with Section 175A(b) of the Act to provide for maintenance of the NAAQS for 10 additional years following the end of the first 10-year maintenance period.

The South Coast Air Quality Management District, among others, challenged EPA’s 2008 ozone implementation rule in *South Coast Air Quality Management District v. EPA* (882 F.3d 1138 (D.C. Cir. 2018)). The court sided with the plaintiffs and vacated the parts of the rule that removed the second maintenance plan requirements for orphan maintenance areas. EPA once again required Clark County to submit a second 10-year maintenance plan for the 1997 ozone NAAQS. DAQ submitted this plan in January 2022, and EPA approved the plan effective May 6, 2024 (89 FR 23916).

Clark County continued to maintain ambient ozone concentrations below the 1997 and 2008 8-hour ozone NAAQS, but EPA revised and lowered the standard in 2015. EPA set the new NAAQS at a maximum concentration of 0.070 ppm, based on a three-year average of the annual fourth-highest daily maximum 8-hour average concentration (80 FR 65292).

In 2016, NDEP recommended that EPA designate HAs 164A, 165, and 212 as nonattainment for the 2015 8-hour ozone NAAQS based on 2013–2015 monitoring data. On December 20, 2017, EPA issued a 120-day notice letter notifying NDEP that it intended to also designate HA 216 as nonattainment after considering multiple factors and design value data from 2014–2016 (83 FR 651; Strauss 2017). NDEP responded in February 2018 with a recommendation that EPA designate HAs 164A and 165 as attainment to reflect 2015–2017 data, which demonstrated design values below the 2015 8-hour ozone NAAQS, and to designate HA 216 as attainment because meteorological conditions show the area does not contribute to ambient concentrations in the Las Vegas Valley (Lovato 2018). EPA agreed, designating only HA 212 as a marginal nonattainment area in June 2018 (83 FR 25776) and requiring that DAQ bring the area into attainment by August 3, 2021, based on the 2018–2020 ozone design value.

DAQ identified 28 exceedance days at area monitors between 2018 and 2020 that it maintains were caused by exceptional events (e.g., wildfires, stratospheric intrusions). In accordance with 40 CFR Part 50.14 (Exceptional Events rule), DAQ submitted 17 exceptional event demonstrations to EPA Region 9 that included data, modeling, and other information to support excluding those exceedance days from the calculation of HA 212’s 2018–2020 design value.

After reviewing the submittals, Region 9 decided the weight of evidence did not support a finding that exceptional events caused exceedances in HA 212 on June 19–20, 2018; May 6, 2020; May 9, 2020; June 22, 2020; and June 26, 2020 (88 FR 775). EPA deferred reviewing data exclusion requests on all other dates after determining that any findings would not affect a decision on HA 212’s attainment status or qualification for a one-year extension to demonstrate attainment. Based on EPA’s decision, HA 212’s 2018–2020 design value is 0.074 ppm, above the 0.070 ppm design value required to demonstrate attainment (as required by 40 CFR Part 50.19) by the specified date.

EPA proposed reclassifying HA 212 to “moderate” nonattainment for the ozone NAAQS on July 22, 2022, and finalized the decision on January 5, 2023 (88 FR 775). DAQ must now demonstrate HA 212 will attain the NAAQS by August 3, 2024, based on a 2021–2023 ozone design value.

Figure 1 shows the areas within Clark County previously designated as nonattainment for the 1997 8-hour ozone NAAQS, and the portion now designated as moderate nonattainment for the 2015 8-hour ozone NAAQS.

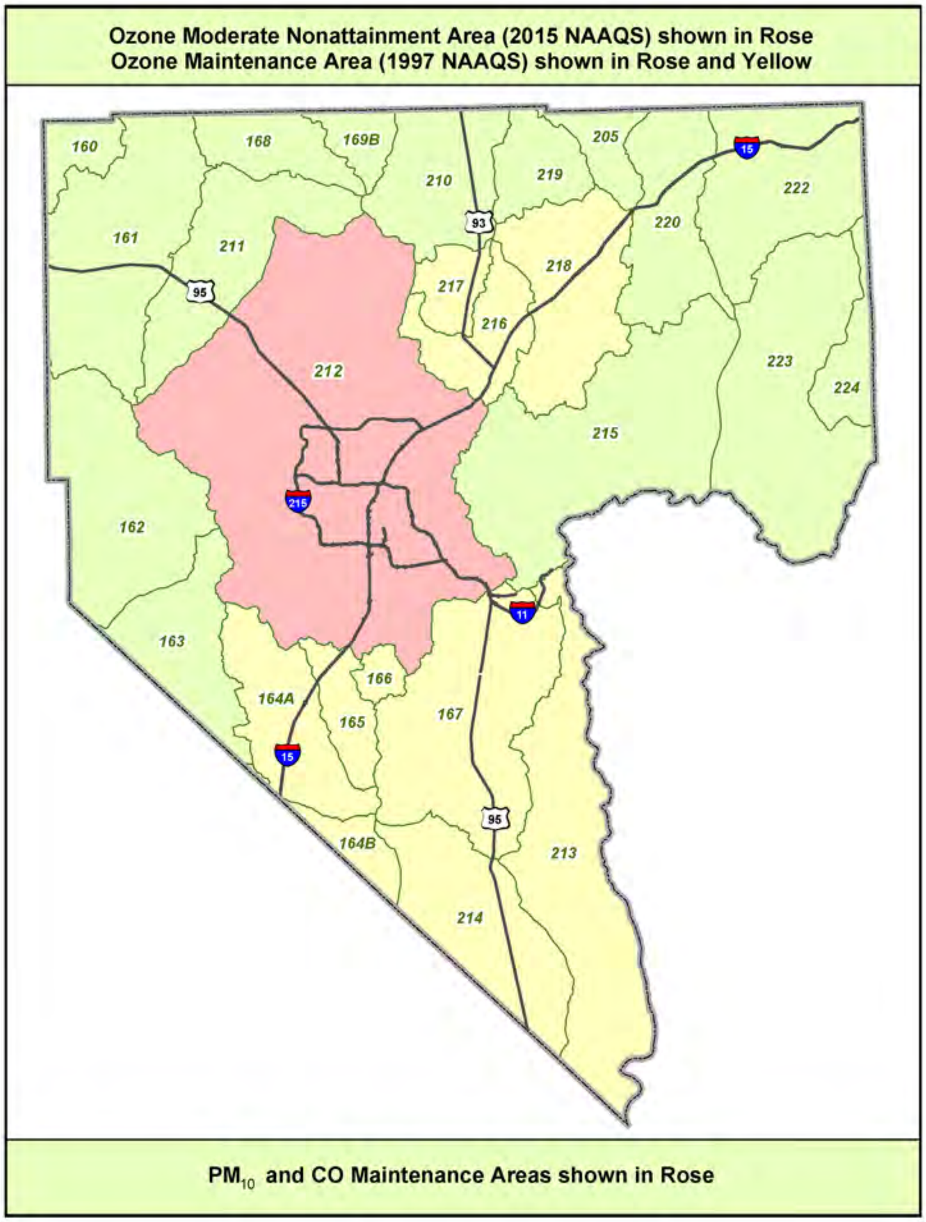

Figure 1. 1997 8-hour Ozone NAAQS Maintenance Area and 2015 8-hour Ozone NAAQS Moderate Nonattainment Area (HA 212) in Clark County.

1.4 IMPLEMENTATION PLAN REQUIREMENTS

EPA set forth SIP requirements for the 2015 8-hour ozone NAAQS at 40 CFR Part 51, Subpart CC. The new NAAQS retained most of the requirements adopted for the 2008 8-hour ozone NAAQS (80 FR 12264), which stemmed directly from the Act.

Section 172 of the Act contains general planning requirements that state or local air pollution control agencies must meet for nonattainment areas. These include a SIP[1] that requires implementation of reasonably available control measures (RACM) as expeditiously as practicable and reasonable further progress (RFP) in attaining the NAAQS. Attainment plans must contain:

- An emissions inventory (for the ozone NAAQS, this includes VOC and NO_x emissions based on a typical summer day), as well as an identification and quantification of emissions growth that is consistent with Reasonable Further Progress (RFP) requirements;
- A preconstruction permit program for new and modified major stationary sources;
- Other control measures necessary to bring an area into attainment by its attainment date; and
- Contingency measures to apply if an area fails to meet RFP or its attainment date.

Section 182(b) of the Act contains additional SIP requirements specific to moderate ozone nonattainment areas like HA 212. These include:

- Demonstration of a 15% Rate-of-Progress (ROP) from base year emissions;
- Specific annual emissions reductions to meet RFP requirements;
- Reasonably available control technology (RACT) for any source category for which EPA has published a control technique guideline (CTG) document;
- RACT for major sources of VOC and NO_x;
- A motor vehicle inspection and maintenance (I/M) program; and
- Major New Source Review (NSR) nonattainment area requirements.

EPA regulations set timelines for submitting planning documents to EPA for approval: for example, 40 CFR Part 51.1315 requires submittal of the base year emissions inventory within two years of the effective date of a nonattainment designation. (For HA 212, the required submittal deadline was August 3, 2020.) On September 1, 2020, the BCC adopted an emissions statement program and a base year (2017) emissions inventory for the 2015 8-hour ozone NAAQS. EPA approved the emissions statement program on July 29, 2022 (87 FR 45657) and the emissions inventory on November 14, 2022 (87 FR 68057) as revisions to the Nevada SIP.

[1] The state plan, under Section 110 of the Act, is a collection of control measures, strategies and rules known as a state implementation plan or a federal implementation plan (when EPA promulgates federal requirements into the state plan). The term "state plan" has waned and instead the state plan as a whole and the individual requirements within it are generally referred to as the SIP.

40 CFR Parts 51.1310 and 51.1314 require that, three years from the date of designation, areas initially designated as moderate nonattainment submit an RFP demonstration (including ROP measures) and major NSR requirements. Neither section addresses deadlines for areas reclassified after an initial designation (as HA 212 was). Parts 51.1308 and 51.1312 allow up to three years from an initial designation for an air pollution control agency to submit an attainment demonstration, including a RACM plan, but do not supply a deadline for areas that EPA subsequently reclassifies to a higher ozone classification.

40 CFR Part 51.1308 also contains the requirements for submission of a RACT SIP to EPA. An air pollution control agency has two years from the effective date of a reclassification to submit a RACT SIP unless the Administrator establishes a different deadline.

Rather than allowing for the two years provided in the rule, EPA set a retroactive deadline of January 1, 2023, in its January 5, 2023, reclassification action for NDEP to submit a moderate area SIP containing all required elements for the HA 212 moderate nonattainment area. On October 18, 2023, EPA issued NDEP a finding of failure to submit with respect to HA 212 (88 FR 71757).

This document provides all the information required to satisfy SIP planning requirements for HA 212 and resolve the finding of failure to submit.

2.0 EMISSIONS INVENTORY

2.1 INTRODUCTION

In support of the development of a moderate ozone attainment plan for the 2015 Ozone National Ambient Air Quality Standard, DAQ developed 2017 (base year) and 2023 (future year) ozone season weekday anthropogenic emissions estimates for ozone precursors within HA 212, collectively referred to as the 2015 Ozone NAAQS SIP Inventory ("modeled inventory") (Ramboll US Consulting, Inc. 2023, Attachment A). The ozone season day emissions inventory represents emissions on a typical summer weekday (not a holiday). The source categories included in the 2015 Ozone NAAQS SIP Inventory include all anthropogenic emissions categories: stationary point sources, stationary nonpoint (area) sources, on-road mobile sources, nonroad mobile sources, airports, and locomotive sources. The nonpoint source category inventory includes emissions from railways, residential wood combustion, and agriculture/livestock. The primary data sources for the 2015 Ozone NAAQS SIP Inventory include locally specific activity data, the 2017 Emissions Modeling Platform (EMP) based on the 2017 National Emissions Inventory (NEI), and 2016v2 EMP 2023 projections (EPA 2022a).

DAQ used the 2015 Ozone NAAQS SIP Inventory to model attainment with the 2015 Ozone NAAQS and establish the MVEBs (Ramboll US Consulting, Inc. 2024a, Attachment B), which were used to determine the number of emissions reductions required as a contingency measure. DAQ did not use the 2015 Ozone NAAQS SIP Inventory for the ROP demonstration; it developed a separate inventory (ROP Inventory) based on an updated EPA modeling platform[2] (Ramboll US Consulting, Inc. 2024b, Attachment F). Section 8.0 discusses the ROP inventory and analysis.

Attachment A to this plan contains a full description of the 2015 Ozone NAAQS SIP Inventory methodology and quality assurance procedures.

2.2 SOURCE CATEGORIES

2.2.1 On-road Motor Vehicle Emissions

On-road mobile sources include automobiles, motorcycles, buses, and trucks traveling on local roads and state and national highways. DAQ ran EPA's Motor Vehicle Emissions Simulator, version 3.1 (MOVES3.1) in inventory mode to develop on-road mobile source emissions estimates for HA 212. MOVES3.1 includes 13 source types and 4 roadway types. DAQ developed updated county-specific MOVES input databases for the 2017 base year and the 2023 future year based on available information. Key MOVES inputs include such vehicle fleet activity data as vehicle miles traveled, vehicle population by vehicle source type (or vehicle class), fleet age distribution, fuel parameters, and inspection and maintenance (I/M) programs. Since vehicle classification is a crucial component for developing an on-road emission inventory, DAQ completed a vehicle classification

[2] Four EPA modeling platforms are cited in this document: 2016v1 (released 2021); 2016v2 (released 2022); 2017 (released 2022); and 2016v3 (released 2023). The term "emissions modeling platform" (EMP) refers to emissions data taken from one of these platforms.

study in June 2018. The study used 2014–2016 traffic count data collected by the Nevada Department of Transportation and included an on-road license plate survey at selected roadway locations.

2.2.2 Nonroad Mobile Source Emissions

Nonroad mobile sources include a wide variety of motorized equipment types that either move under their own power off the roadway network or can be moved from site to site. The nonroad mobile source 2017 and 2023 emissions estimates were taken from the 2017 EMP and 2016v2 EMP 2023 projections, respectively, which are based on the nonroad module of MOVES3. To develop HA 212 subcounty ozone season weekday nonroad emissions estimates, DAQ ran the Sparse Matrix Operator Kernel Emissions (SMOKE) model for weekdays of a single week in July on a grid covering HA 212 with 4-km grid spacing. The total emission estimates within the modeling domain were summed for NO_x and VOC and averaged over all five weekdays.

2.2.3 Nonpoint Source Emissions

Nonpoint sources are stationary sources that fall below point source reporting levels and are too numerous or small to identify individually, e.g., small-scale industrial or residential operations that use emission-generating materials or processes. DAQ accessed the 2017 and 2023 nonpoint emissions from the 2017 EMP and 2016v2 EMP 2023 projections, respectively, to develop the HA 212 subcounty inventory. The nonpoint source category includes locomotives, volatile chemical products (“VCP”), commercial combustion, asphalt paving, residential wood combustion, and other area sources. The 2016v2 EMP uses EPA’s new approach and data to derive emissions for VCP sources; the 2017 EMP and previous emissions inventories reported VCP emissions based on an older methodology. To obtain 2017 VCP estimates based on a consistent methodology, DAQ linearly interpolated VCP emissions reported in the 2016v2 EMP between 2016 and 2023 instead of using emissions from the 2017 EMP. DAQ ran the SMOKE model for weekdays of a single week in July on a grid covering HA 212 with 4-km grid spacing. The total emission estimates within the modeling domain were summed for NO_x and VOC and averaged over all five weekdays.

2.2.4 Point Source Emissions

Point sources are larger stationary sources that emit pollutants above mandatory reporting levels and must be permitted by DAQ. Examples include power plants, industrial boilers, and other such industrial/commercial facilities. Clark County’s point source inventory includes all Title V stationary sources and all minor sources within HA 212 with the potential to emit at least 10 tons of VOC or 25 tons of NO_x. Point source 2017 emissions inventories were obtained from 2017 annual reports submitted by individual stationary sources; 2023 emissions were obtained from the technical support document for the second maintenance plan for the 1997 8-hour ozone NAAQS (DES 2021a), which used the 2016v1 EMP to calculate emissions growth factors. Point source emission inventories were developed from data either collected by direct on-site measurements or calculated using EPA or locally derived emission factors and source-specific activity data. Emissions from all minor sources emitting less than 10 tons of VOC or 25 tons of NO_x were included in the nonpoint source category.

2.2.5 Commercial Aviation Emissions

Commercial aviation within HA 212 covers emissions from three airports: Harry Reid (formerly McCarran) International Airport, North Las Vegas Airport, and Henderson Executive Airport. The Clark County Department of Aviation (DOA) provided 2017 actual and 2023 future year emissions for commercial aviation. The emission inventories were developed using the Federal Aviation Administration's Aviation Environmental Design Tool, Version 3b; DOA calculated design day emissions using the default meteorology in the tool. The design day was in October, so DOA developed correction factors to account for the differences in meteorology between the design day and a typical summer weekday. These correction factors were applied to the emission inventories for all three airports.

2.2.6 Federal Aviation Emissions

Federal aviation emissions in HA 212 occur mostly at Nellis Air Force Base (NAFB). The 2017 actual and 2023 projected emissions from aircraft operations were obtained from Clark County's second maintenance plan for the 1997 8-hour ozone NAAQS (DES 2021b).

2.2.7 Banked Emissions Reduction Credits

DAQ may grant Emission Reduction Credits (ERCs), under strict guidelines and upon request, to an emissions source that voluntarily reduces emissions beyond required levels of control. ERCs may be sold, leased, banked for future use, or traded in accordance with applicable regulations. Once used to offset emissions, they are permanently retired. ERCs are intended to provide an incentive for reducing emissions and to establish a framework to promote a market-based approach to regulating air pollution. DAQ included banked ERCs in the emissions inventory.

2.3 EMISSION INVENTORY RESULTS

Table 1 shows 2017 and 2023 HA 212 NO_x emissions estimates by source category for a typical ozone season weekday. The 2023 NO_X emissions inventory does not include reductions from any new local control measures. DAQ projects that the total NO_x emissions inventory will decrease by 28.6 tpd in 2023. Emissions in the point source and airport categories are projected to increase in 2023, but DAQ projects that turnover in nonroad and on-road fleets will offset these emissions increases.

Table 1. Summary of HA 212 Ozone Season Weekday NO_x Emissions (tpd)

Source Category	2017 NOx	2023 NOx
Point source	2.92	3.23
Nonpoint source	6.15	4.01
On-road mobile	36.32	19.15
Nonroad mobile	36.98	22.98
Airports (commercial & federal)	11.90	15.52
Locomotives	0.80	0.66
Emission Reduction Credits	—	0.92
Total	**95.07**	**66.47**

As shown in Figure 2, on-road and nonroad mobile sectors are the dominant sources of NO_x emissions, collectively making up over half all NO_x emissions in both 2017 and 2023. Airports are the next largest source category of NO_x emissions in both emissions inventories.

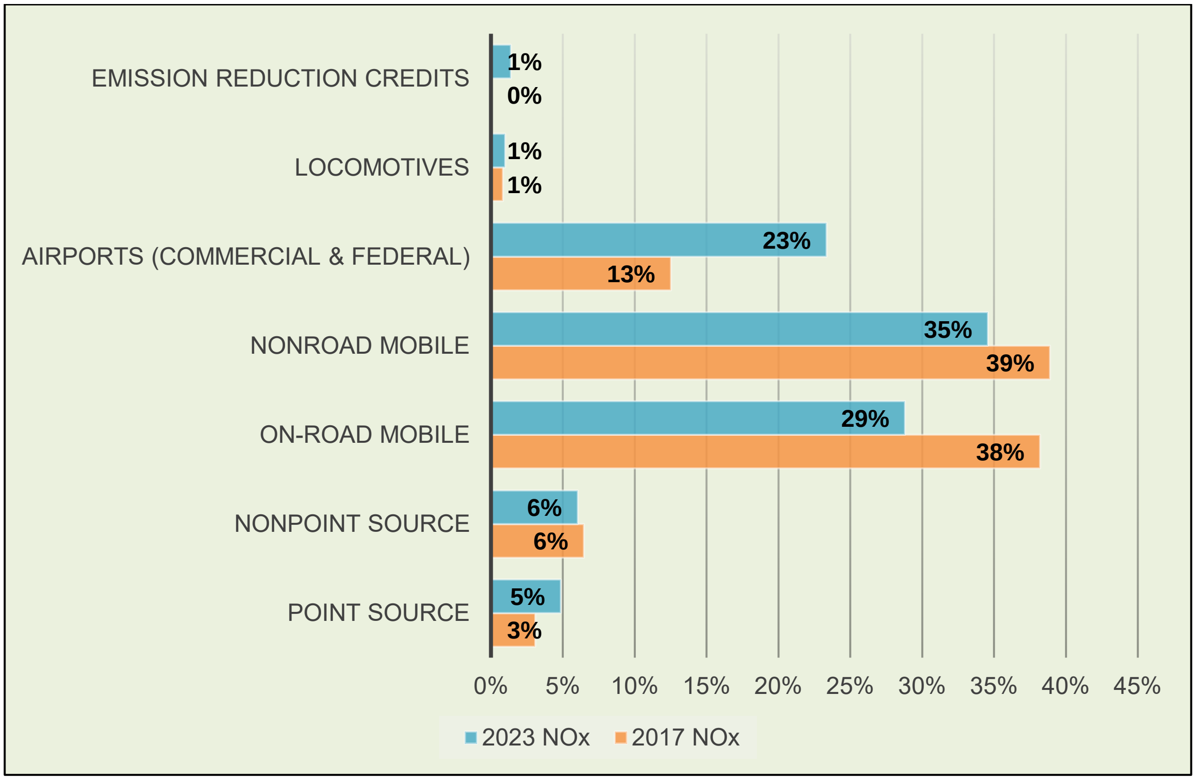

Figure 2. Comparison of NO_x Emissions Inventories for 2017 and 2023 by Percent for Each Emissions Category.

In contrast, as displayed in Table 2, the nonpoint sector is the dominant source of anthropogenic VOCs in the 2017 and 2023 emissions inventories, followed by on-road and nonroad mobile source categories. Slight emissions increases are projected for the point, nonpoint, nonroad mobile and airport source categories for 2023. Emissions decreases in the on-road source category will offset these emissions increases, resulting in a small decrease in total emissions (4.25 tpd VOC). The 2023 VOC emissions inventory does not include reductions from any new local control measures.

Table 2. Summary of HA 212 Ozone Season Weekday VOC Emissions (tpd)

Source Category	2017 VOC	2023 VOC
Point source	1.25	1.32
Nonpoint source	56.05	58.29
On-road mobile	24.43	17.01
Nonroad mobile	24.03	24.17
Airports (commercial & federal)	1.94	2.62
Locomotives	0.04	0.03
Emission Reduction Credits	—	0.05
Total	**107.73**	**103.49**

Figure 3 compares each source category's relative percent of total emissions inventories for both 2017 and 2023.

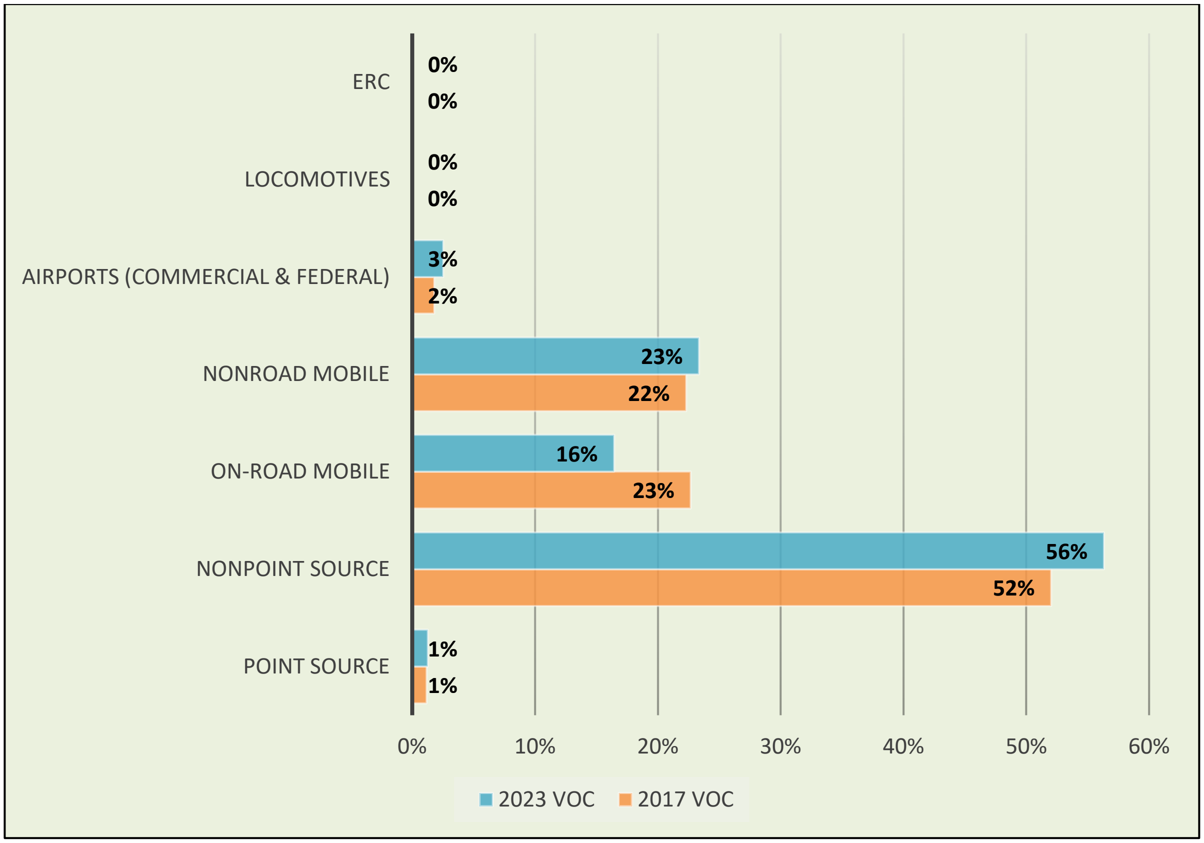

Figure 3. Comparison of VOC Emissions Inventories for 2017 and 2023 by Percent for Each Emissions Category.

2.3.1 Biogenic Emissions

Biogenic emission sources produce VOCs from vegetation and soils such as trees, grass, and crops. Additionally, soils produce a nominal amount of NO_X emissions. Biogenic emission sources produce VOCs from vegetation and soils such as trees, grass, and crops. Additionally, soils produce a nominal amount of NOx emissions. The Biogenic Emission Inventory System (BEIS) estimates natural VOC emissions from vegetation and NOx from soil. Built into the Sparse Matrix Operator Kernel Emissions (SMOKE) processing system, BEIS is driven by gridded, hourly ambient meteorology and land cover data from the Biogenic Emissions Landuse Database (BELD). BELD data provide distributions of hundreds of vegetation classes at 1 km resolution over most of North America.

Three versions of BEIS were developed and applied during the evolution of the EPA 2016 emissions modeling platform used to support modeling for DAQ's moderate ozone attainment plan. BEIS4/BELD6 is the latest version, released in mid-2022. Each of these BEIS versions result in substantially different estimates in biogenic VOC emissions in Clark County. While modeled biogenic NOx and VOC emission rates have trended downward with succeeding versions, the huge range of emission rates among these versions (by factors of 4 to 10+) illustrates the uncertainty in estimating desert biogenic emissions and related vegetative characterization over just the last few years. DAQ concludes that there is far too much uncertainty in the biogenic models to know whether any of them appropriately estimate rural and urban VOC emissions in the desert environment of the southwestern U.S. As described in Section 4.3.5, DAQ adopted BEIS4/BELD6 and processed biogenic emissions on the 36, 12, and 4 km resolution modeling grid system for the entirety of the April-August 2016 modeling period.

Table 3 lists biogenic NO_X and VOC emissions for an average ozone season day in tpd within the HA 212 portion of the 4 km Clark County grid. Values in the table were developed by overlaying a cell mask defining the irregular shape of the HA 212 area onto the 4 km modeling grid (301 total grid cells), and averaging NO_X and VOC emissions over the entire month of July 2016 to represent an ozone season day. Biogenic emissions are held constant between 2016 and 2023.

Table 3. HA 212 Biogenic Emissions for a 2016 Average Ozone Season Day (tpd)

Pollutant	Biogenic Emissions
NO_X	1.0
VOC	22.4

3.0 MONITORING NETWORK

DAQ will continue to characterize ambient air quality in HA 212 by operating a network of ambient air monitoring stations to comply with EPA requirements and guidance. 40 CFR Part 58 (including Appendices A–E) defines the requirements for the ambient air quality monitoring programs mandated by the Act. Under these rules, every state must establish a monitoring network for criteria air pollutants that meets location and operation specifications. Monitors used to satisfy these requirements are called State and Local Air Monitoring Stations (SLAMS). DAQ operates multiple SLAMS in its network that are designed to monitor ambient air concentrations of ozone.

DAQ may also operate Special Purpose Monitors (SPMs) as needed to meet short-term or specific monitoring goals. As outlined in 40 CFR Part 58.20, SPMs do not have to meet the same requirements as SLAMS monitors; instead, SPMs must comply with Appendix A of Part 58. To obtain specific, targeted information and maintain flexibility, DAQ does not operate SPMs in full compliance with 40 CFR Part 58, Appendix E, Sections 2, 3, 4, 5, 6, or 9. Table 4 lists the current monitoring sites in HA 212.

Table 4. Ozone SLAMS Monitoring Sites in HA 212

EPA AQS Site ID	Site Name	Street Address	City	Current Status
32-003-0540	Jerome Mack	4250 Karen Ave	Las Vegas	Active as of Aug. 27, 2010
32-003-0043	Paul Meyer	4525 New Forest Dr	Las Vegas	Active as of Jan. 1, 2003
32-003-0071	Walter Johnson	7701 Ducharme Dr	Las Vegas	Active as of Jan. 1, 2003
32-003-0073	Palo Verde	126 S. Pavilion Center Dr	Las Vegas	Active as of Jan. 1, 2003
32-003-0075	Joe Neal	6076 Rebecca	Las Vegas	Active as of Jan. 1, 2003
32-003-0298	Green Valley	298 North Arroyo Grande	Henderson	Active as of June 4, 2015
32-003-0044	Mountains Edge Park	8101 Mountains Edge Pkwy	Las Vegas	Active as of Sept. 29, 2020
32-003-0299	Liberty High School	3700 Liberty Heights Ave	Henderson	Active as of May 1, 2021
32-003-2003	Walnut Community Center	3075 N Walnut Rd	Las Vegas	Active as of June 1, 2021

Note: AQS = Air Quality System.

DAQ is required to submit an annual network plan to EPA for approval. EPA approved DAQ's 2023 network plan on October 30, 2023. The most recent plan was submitted to EPA in June 2024 (DES 2024) and is awaiting EPA approval.

Figure 4 shows the nine monitoring stations listed in Table 4, as well as others located throughout Clark County.

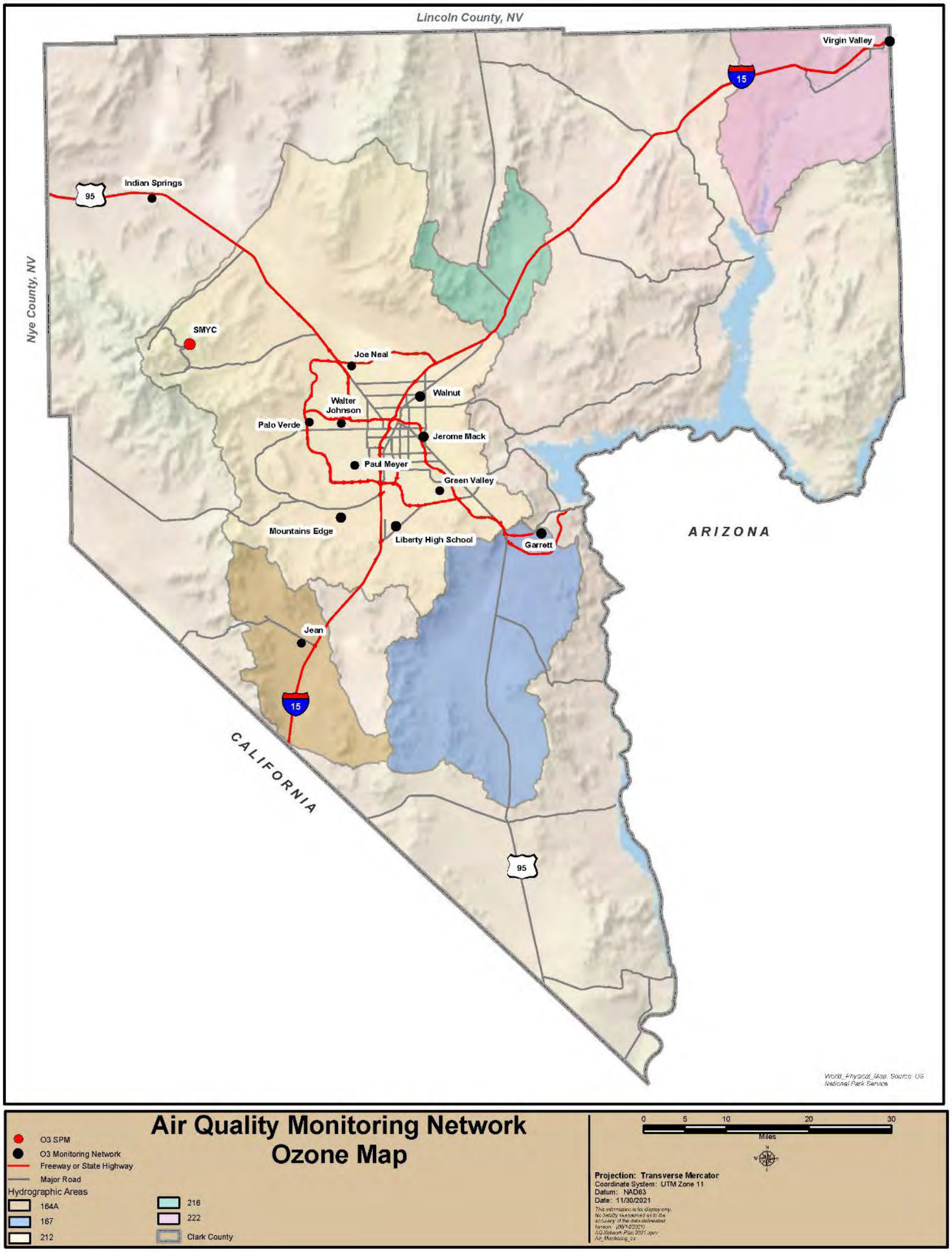

Figure 4. Clark County Ozone Monitoring Stations.

The Spring Mountain Youth Camp (EPA AQS Site ID 32-003-7771) is operated as a nonregulatory SPM monitoring site, as described in the annual network plan. This monitor is not used for NAAQS concentration monitoring, but provides data on stratospheric intrusions and pollutant mixing heights and assists with model validation.

DAQ stores data from these monitors electronically on a data-logger at each monitoring site, then retrieves the data wirelessly and stores them electronically on department servers. DAQ transmits the data to EPA's AQS database after ensuring the following quality control and assurance requirements for ozone have been met:

- > 75% (average) daily maximum and 75% completeness for scheduled sampling days in a calendar year;
- ≥ 75% of hours in an 8-hour period; and
- At least 18 of 24 running 8-hour averages.

Data are available for public review on EPA's Air Data website (https://www.epa.gov/outdoor-air-quality-data). Real-time data are available for viewing on DAQ's monitoring website (https://desaq-monitoring.clarkcountynv.gov/), but have not yet been reviewed to determine whether they meet air quality assurance requirements.

DAQ collects and verifies ozone monitoring data under an EPA-approved Quality Management Plan and a Quality Assurance Project Plan for criteria pollutant and NCore monitoring. DAQ also follows EPA's guidance in the *Quality Assurance Handbook for Air Pollution Measurement Systems, Volume II* (EPA 2017a), available at https://www.epa.gov/sites/production/files/2020-10/documents/final_handbook_document_1_17.pdf. Formal quality assessments are an integral part of the DAQ monitoring plan and assure the monitoring network produces an acceptable level of data quality.

4.0 ATTAINMENT DEMONSTRATION

Section 182(b)(1)(A) of the Act requires that a moderate area attainment plan submission include a demonstration that the plan will achieve attainment with the NAAQS by the attainment date (42 U.S.C. 7511a). EPA's 2015 Ozone NAAQS Implementation Rule (40 CFR Part 51.1308) requires that this attainment demonstration use photochemical grid modeling that meets the modeling guidelines in 40 CFR Part 51, Appendix W and includes inventory data, modeling results, and an emissions reduction analysis.

DAQ's photochemical modeling is based on EPA's 2016v2 modeling platform, which includes Comprehensive Air Quality Model (CAMx)-ready model inputs for emissions, meteorology, initial/boundary conditions, and other ancillary datasets. In the modeling, DAQ used 2016 for the historical base year and 2023 for the future base planning year (i.e., the attainment year). The modeling included EPA input datasets for two nested grids—36US3, covering North America, and 12US2, covering the conterminous US—and a third grid (CC4c2) with 4-km grid spacing covering the entirety of Clark County and portions of surrounding areas in southern Nevada, northwestern Arizona, and southeastern California.

The following sections provide a summary of the ozone trends in HA 212 and information on the modeling analysis, including summaries on model selection, model validation, emissions and meteorological inputs, control measures included in the modeling, a weight of evidence analysis, and model results. Attachment B provides the complete analysis.

4.1 OZONE TRENDS

As Figure 5 illustrates, ozone design values (i.e., the fourth highest daily maximum 8-hour average concentration, averaged over a three-year period) for Clark County, including HA 212, showed a steady decline between 2007 and 2010. Since 2010, design values within the county have ranged between a low of 0.073 ppm and a high of 0.078 ppm (73 and 78 parts per billion (ppb), respectively).

Since its designation as a moderate ozone nonattainment area, HA 212's design values have continued to show concentrations above the 2015 ozone NAAQS maximum permissible concentration of 0.070 ppm on a three-year average of the annual fourth-highest daily maximum 8-hour average concentration. Figure 6 shows design values for monitors within HA 212. (Mountain's Edge began operating in 2020; Liberty High School and Walnut Community Center began operating in 2021.)

Because attainment cannot be demonstrated based on historical design values, DAQ performed modeling to identify contributions to ozone concentrations and study the effectiveness of various control measures on future projected design values.

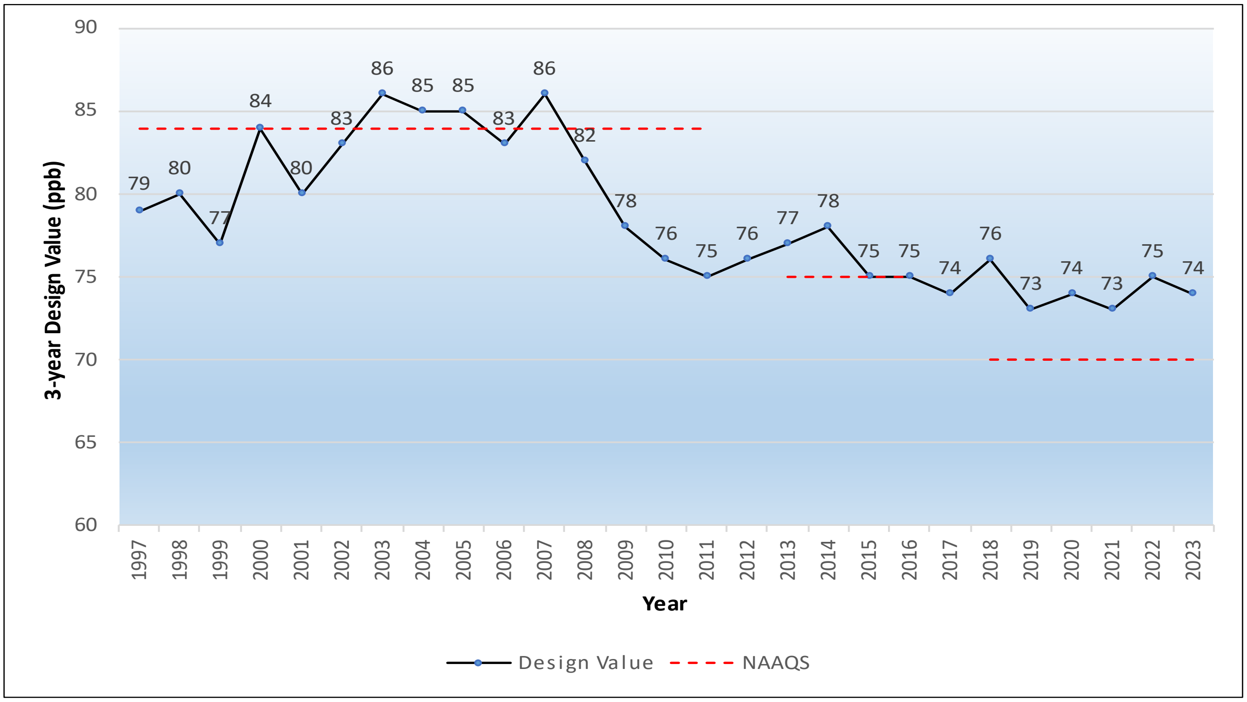

Figure 5. Clark County 8-hour Ozone Design Values (2000-2023).

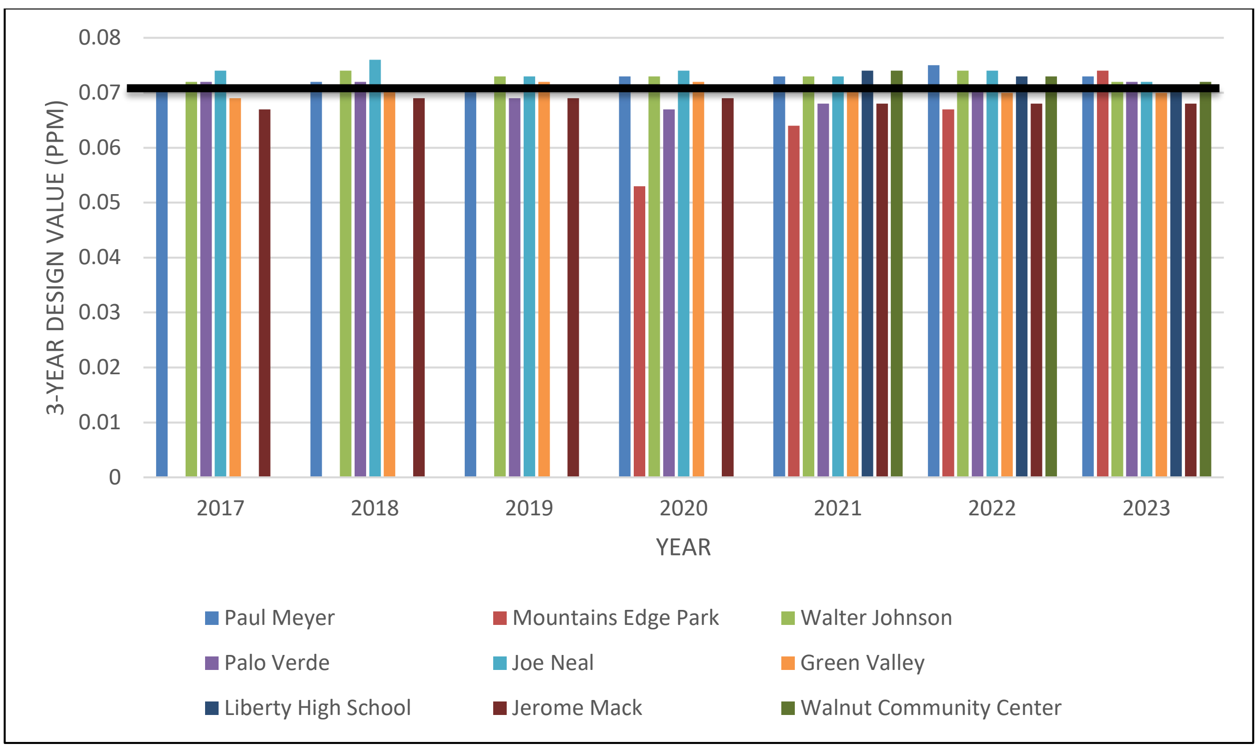

Figure 6. HA 212 Ozone Design Values (ppm) 2017-2023 for each Monitoring Site.

4.2 ATTAINMENT MODELING RESULTS

Photochemical grid modeling using CAMx (as described in Attachment B and summarized in Section 4.3) predicts no exceedances of the 2015 ozone NAAQS in the 2023 future base case analysis, which was conducted without considering any additional control measures. The highest predicted 2023 future design value is 69 ppb at the Joe Neal monitoring site. Reductions in transported, on-road mobile source emissions from California are predicted to allow HA 212 to achieve attainment without additional local control measures.

Following implementation of four Control Technology Guideline (CTG) RACT regulations[3] and other potential local control measures,[4] CAMx modeled continued attainment with the 2015 ozone NAAQS with a reduced 2023 predicted design value of 68.8 ppb at Joe Neal. Emissions reductions estimated for this modeling simulation were based on the 2016v2 EMP; thus they differ from the 15% ROP analysis, which is based on EPA's 2016v3 EMP and emissions reductions occurring in 2026 rather than 2023.

Table 5 lists modeled 2023 design values with and without added control measures for each monitoring site. All values are below the 2015 ozone NAAQS of 70 ppb.

Table 5. 2023 CAMx Modeled Design Values for HA 212 Monitoring Sites With and Without Additional Control Measures

Monitor Site ID	Site Name	2023 Design Value: No Added Emissions Controls (ppb)	2023 Design Value: Added Control Measures[1] (ppb)	Difference (ppb)
320030022	Apex	65.2	65.2	0.0
320030023	Mesquite	57.2	57.2	0.0
320030043	Paul Meyer	67.7	67.5	-0.2
320030071	Walter John-son	67.9	67.5	-0.4
320030073	Palo Verde	67.2	66.9	-0.3
320030075	Joe Neal	69.0	68.8	-0.2
320030298	Green Valley	67.3	67.1	-0.2
320030540	Jerome Mack	64.1	64.0	-0.1
320030601	Boulder City	61.5	61.5	0.0
320031019	Jean	63.9	63.9	0.0
320032002	J.D. Smith	67.3	67.1	-0.2
320037772	Indian Springs	62.3	62.2	-0.1

[1] Control measures included in modeling were four CTG RACT rules (AQRs 104–107 at 3% max VOC concentration) and two OTC model rules (consumer products (Phases I–IV) and AIM coatings (Phases I–II)), totaling an 18% emissions reduction in the modeled future nonpoint solvent sector emissions inventory.

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[3] AQR 104 for industrial cleaning solvents; AQR 105 for metal solvent degreasers; AQR 106 for graphic arts; and AQR 107 for cutback asphalt.

[4] Ozone Transport Commission (OTC) model rules for consumer products (Phases I–IV) and for architectural and industrial maintenance (AIM) coatings (Phases I–II).

CAMx modeling showed that natural and transported emissions are the primary contributors to ambient ozone concentrations in HA 212 and that implementation of additional control measures would decrease the predicted 2023 design value concentration by less than 0.2% (0.02 ppb) despite an 18% VOC emissions reduction.

EPA's own modeling for interstate transport is consistent with this attainment demonstration, further supporting the conclusion that HA 212 can model attainment with the 2015 ozone NAAQS by the 2024 attainment date without the need for additional local emissions reductions. Specifically, EPA's initial (2016v2) and final (2016v3) interstate transport modeling analyses project average design values consistent with CAMx attainment modeling. These models show that HA 212 could attain the 2015 ozone NAAQS by 2024, and that Californian and open-area land fires collectively contribute as much to Joe Neal's design value as Nevada. EPA's modeling also showed, consistent with DAQ's CAMx modeling, that most ozone is transported into the Las Vegas Valley.

The following table compares modeled ozone design values for each monitoring station using EPA and DAQ modeling, and shows all predicted concentrations are below the NAAQS.

Table 6. Comparison of 2023 Predicted Ozone Design Concentrations Using Three Different Photochemical Grid Models

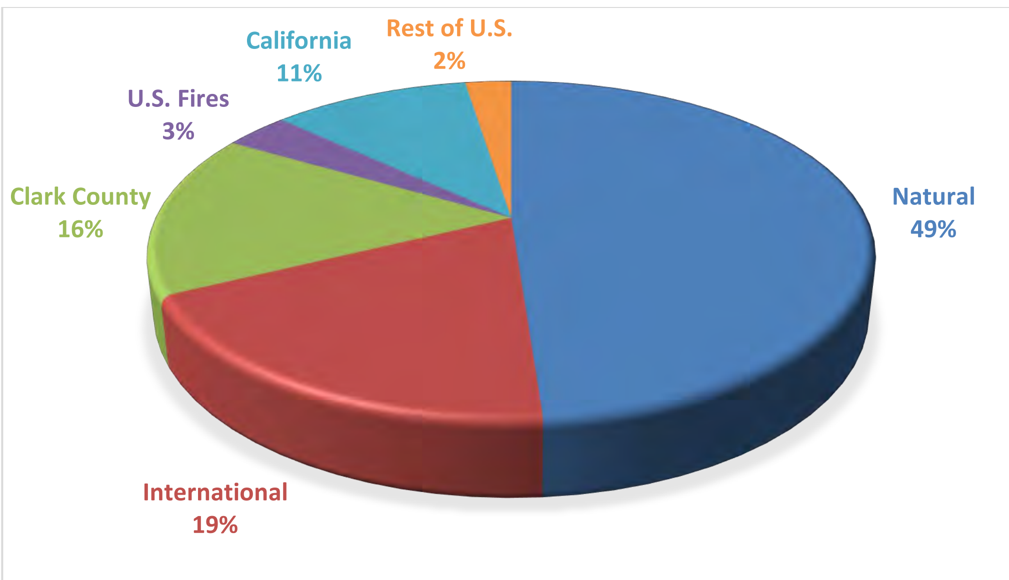
Monitor Site ID	Site Name	EPA 2016 v.2 (ppb)	EPA 2016v.3 (ppb)	DAQ CAMx Attainment Demonstration Model (ppb)
320030022	Apex	66.1	65.6	65.2
320030023	Mesquite	58.3	58.5	57.2
320030043	Paul Meyer	68.5	68.4	67.7
320030071	Walter Johnson	67.7	67.9	67.9
320030073	Palo Verde	67.7	67.9	67.2
320030075	Joe Neal	70.0	69.9	69.0
320030298	Green Valley	66.6	66.8	67.3
320030540	Jerome Mack	65.0	64.4	64.1
320030601	Boulder City	61.8	62.2	61.5
320031019	Jean	64.8	64.4	63.9
320032002	J.D. Smith	67.9	67.5	67.3
320037772	Indian Springs	65.1	63.8	62.3

DAQ used EPA's Software for Model Attainment Test - Community Edition to (1) shift the base year design value from 2016 to 2017 to simulate variability in design value predictions over the base year; and (2) exclude exceptional event-like days in attainment year design value projections. Lower design values are predicted for both scenarios at all monitoring sites. For Joe Neal, using 2017 as the base year lowered the 2023 predicted average design value to 68.4 ppb. Removing wildfire-influenced days eliminated modeled exceedances of the 2015 ozone NAAQS in the base year and resulted in a predicted 2023 average design value of 67.5 ppb at Joe Neal.

Finally, DAQ adjusted 2000–2022 ozone design value trends for meteorological influences, beginning in 2016, with and without removing wildfire-influenced days. The analyses show that without adjusting for meteorology, ozone trends over the past ten years have flattened despite substantial

NO_x and VOC emissions reductions (56% and 26%, respectively) over the last seven years. Removing wildfire-influenced days, however, consistently reduced predicted design values by 1–5 ppb between 2016 and 2023. Conversely, adjusting the trends for meteorology shows wide fluctuations in predicted year-to-year ozone design values, with potential values exceeding the 2015 ozone NAAQS in some instances. This demonstrates that meteorology and wildfire activity may play a larger role than local control measures in achieving attainment or continuing nonattainment (see Attachment I for more information on wildfire atypical event analyses).

The overall findings of these modeling analyses are consistent with source apportionment modeling, which suggests that external, uncontrollable factors significantly impact ambient ozone concentrations in HA 212. Source apportionment modeling of the 2023 future base case shows that Clark County's local emissions contribute only 11 ppb (16%) to the total 69 ppb design value at Joe Neal. Other significant contributors are natural emissions (e.g., lightning, biogenic and oceanic sources), international transport, and transport of anthropogenic emissions from upwind California monitoring sites located within the Mojave Desert. Figure 7 displays the relative contributions of different geographic regions to the 2023 base case projected design value at Joe Neal.



Note: Natural emissions include lightning and biogenic & oceanic emissions.

Figure 7. Percent Contribution by Region to Joe Neal 2023 Base Case Projected Design Value (69 ppb).

As shown, international emissions contribute 19% to the modeled design value. Section 179B(a) of the Act provides that EPA shall approve an implementation plan revision when the plan meets the requirements of the Act and demonstrates that it is adequate to attain and maintain the NAAQS but for international emissions. The source apportionment analysis satisfies this demonstration.

The accuracy of these design value predictions relies on the accuracy of the regional anthropogenic emissions inventory, influence of wildfires, and chemistry and dispersion patterns that characterize transport in CAMx simulations. Source apportionment modeling further showed that Clark County emissions resulted in a fairly balanced mix of NO_x- and VOC-sensitive ozone production over the top 10 simulated days, although with some substantial variations day-to-day. This is typical of a local "transitional" regime, where ozone responds to changes in both NO_x and VOC.

Because local emissions are a small contributor to ambient ozone concentrations and 84% of sources are uncontrollable, there are few opportunities to generate local emissions reductions that will produce a sizable effect on the predicted ozone design value. The following figures show the relative size of Clark County's anthropogenic contributions by source category compared to the 2023 predicted design value at Joe Neal (assuming solvent emissions are nonpoint sources).

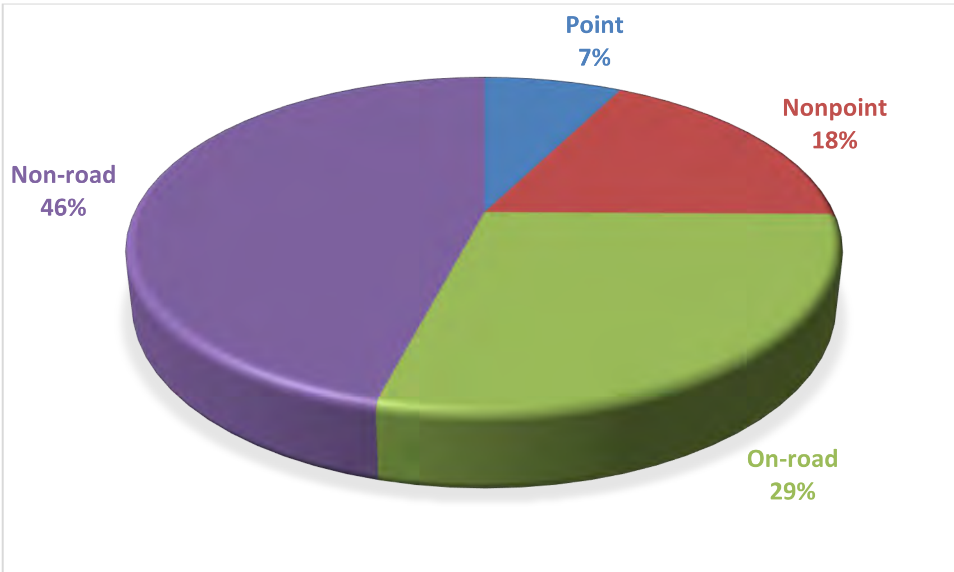


Figure 8. Percent Contribution by Source Category of Clark County's Total Contribution (11 ppb) to the 2023 Predicted Design Value for HA 212.

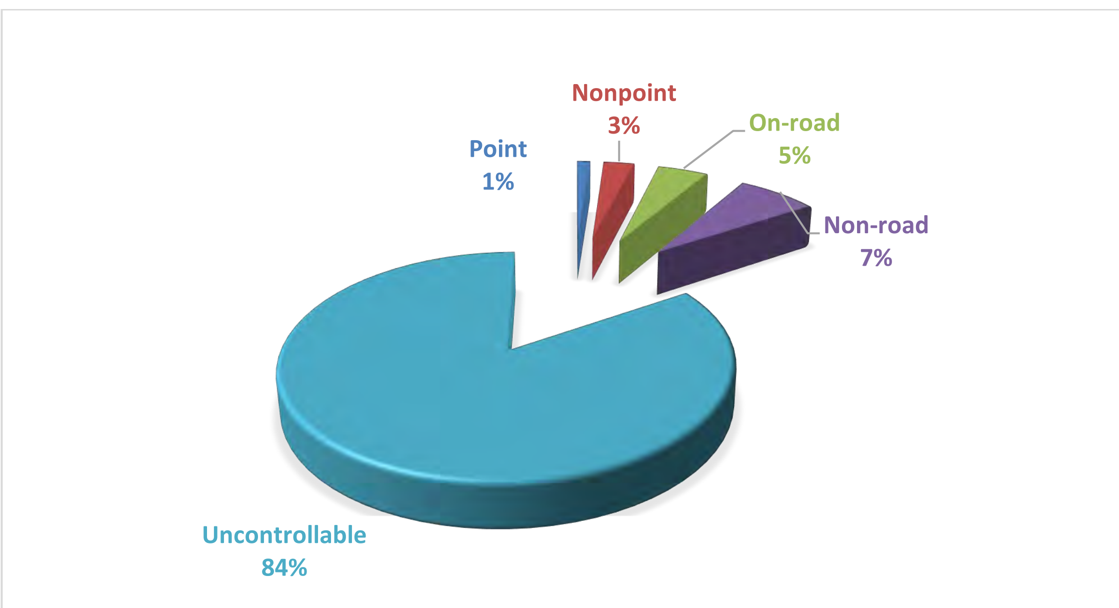


Figure 9. Joe Neal's 2023 Base Case Projected Design Value (69 ppb), Including a Parsing of Clark County's 16% (11 ppb) Anthropogenic Contribution.

These figures suggest there is little opportunity for DAQ to adopt point (stationary) source control measures to reduce ambient ozone concentrations in HA 212. Even emissions reductions from larger contributors (i.e., on-road and non-road source categories), which collectively contribute only 8 ppb (12%) to the 2023 predicted design value of 69 ppb, may not provide opportunities for emissions reductions that would have sizable effects on predicted ozone design values.

4.3 MODEL DESIGN

This section summarizes CAMx model design and modeling.

4.3.1 Model Selection

When EPA reclassified HA 212 to a moderate ozone nonattainment area, DAQ was faced with developing an attainment demonstration to meet a retroactive attainment plan submission deadline. DAQ therefore opted to use readily available, EPA-approved models and datasets to conduct photochemical grid modeling for the attainment demonstration. The selected models included CAMx with extensions in conjunction with the SMOKE model, the Weather Research and Forecasting (WRF) Model, BEIS, and MOVES3 (Section 2.0 in Attachment B describes each model in detail).

CAMx simulates the evolution of pollutant ambient air concentrations in response to variations in emissions and weather over many temporal and geographic scales. The model also allows users to conduct source apportionment studies to identify contributions to ambient ozone concentrations. As described in Attachment B, it satisfies all of EPA's model selection criteria and has been approved for use in numerous ozone and particulate matter SIPs throughout the United States; moreover, EPA has used CAMx to support its own regulatory initiatives. CAMx showed that no additional local control measures are needed to model attainment with the 2015 ozone NAAQS by the 2023 attainment year. DAQ also modeled emissions reductions from potential control measures to demonstrate their effectiveness in further reducing air pollution by the 2023 attainment year.

4.3.2 Modeling Base Year and Period

EPA advises that the modeling period include air quality that is representative of the base year design value and close in time to the NEI. In addition to other criteria, modeling should include periods of both high and low concentrations and simulate a variety of weather impacts on pollutant ambient air concentrations (EPA 2018). DAQ selected the period of May through August for attainment modeling because ozone values in HA 212 are then at their highest levels each year.

For the base year, DAQ selected 2016 because the 2016v2 EMP provides a complete set of model-ready inputs for the summer of 2016, emissions projections for 2023, and a robust foundational database from which to develop inputs for the local Clark County modeling domain. Given the retroactive deadline for the attainment plan submission, using the 2016 base year from the 2016v2 EMP streamlined data inputs for attainment modeling.

Using 2016 also met EPA's recommendations for the base year. Although the most recent NEI occurred in 2020, the data were impacted by the Covid-19 pandemic, making the 2017 NEI a more reliable assessment of normal emissions. The 2016 base year is close in time to the 2017 NEI. In addition, the 2016v2 EMP used a 2016 base year that was largely based on the 2017 NEI (with some recent adjustments). The year 2016 also includes the largest number of exceedance days at the peak monitoring site (Joe Neal) compared to more recent years, and the 2016 design value for HA 212 (75 ppb) is close to the attainment base year's design value (74 ppb) and the 2022 design value (75 ppb). More recent years have also seen increased emissions from wildfires, making them less representative of local air quality impacts. The base year of 2016 contains more days influenced by local or typical regional transport influences. For these reasons, the 2016 base year was appropriate.

4.3.3 Modeling Domain

For the modeling domain, DAQ used the same 36US3 and 12US2 grids used by EPA in the 2016v2 EMP, but added a 4-km grid (CC4c2) covering Clark County, Nevada. The vertical grid structure was defined by the three-dimensional datasets EPA developed for the 2016v2 EMP, which in turn was based on WRF simulations EPA developed to drive the photochemical grid modeling system. Attachment B provides detailed information on grid parameters and resolution.

4.3.4 Base Year Meteorological Inputs

DAQ used preexisting CAMx meteorological inputs for the 36US3 and 12US2 grids from the 2016v2 EMP. CAMx meteorological inputs for the CC4c2 grid were developed from a separate 2016 WRF simulation EPA performed. The most recent version of WRFCAMx (v5.2) was used to map EPA's WRF meteorological output data onto the CC4c2 domain (App. B, Figures 4-2 and 5-1).

The EPA WRF 4-km simulation characterized meteorological conditions well overall and met statistical benchmarks against observed conditions: specifically, the WRF simulations performed well in replicating surface temperature, wind, and vertical profiles for temperature and humidity. While the WRF simulation tended to overstate surface humidity, that variable has the least influence on CAMx ozone model performance; however, some larger wind and temperature errors occurred in modeling high ozone periods, particularly on July 1–2, resulting in poorly simulated convection activity.

To address this shortcoming, DAQ conducted a short WRF simulation based on numerous WRF comparison studies conducted for the Western Regional Air Partnership (WRAP) and the state of New Mexico. The revised simulation performed well in considering winds, temperature, humidity, and rainfall patterns, so DAQ used this to bridge the July 1–2 period in the model. These simulation inputs resulted in a drier, less cloudy, warmer environment within the photochemical model. Even if overstated, these conditions maximized the potential for generating higher ozone on locally driven ozone exceedance days.

WRF output was processed to CAMx-ready inputs on the CC4c2 modeling grid using the WRF-CAMx interface program. WRF output to model-ready inputs was processed for the Community Multiscale Air Quality System model using the Meteorology-Chemistry Interface Processor. Sections 5.0 and 7.0 of Attachment B describe the assessment of meteorological inputs.

4.3.5 Base Year and Projected Emissions Inventory

For the base year, DAQ used the 2016v2 EMP developed by EPA (2016fj; 2023fj) for point source, nonpoint source, on- and off-road, and open area land fires, but made refinements for county-specific data on the CC4c2 grid. The 2016v2 EMP includes a full suite of the base year (2016) and future year (2023) emissions inventories, updated with new VCP estimates, ancillary emissions data, and scripts and software for preparing emissions to support air quality modeling. EPA based 2016v2 EMP estimates on updated MOVES3.1 mobile source modeling, the 2017 NEI's nonpoint source inventory, Western Regional Air Partnership's oil and gas inventory, and updated inventories for Canada and Mexico.

To estimate biogenic emissions, DAQ evaluated four different models: BEIS3.6/BELD4, BEIS3.7/BELD5, BEIS4/BELD6, and MEGAN3.2. They produced wide variations in estimated emissions, signifying an area of uncertainty in the model. After evaluating all models, DAQ elected to use the most recent BEIS4/BELD6 model; its estimated emissions agreed with EPA reports on biogenic emissions in the western U.S., and it was better at predicting ozone concentrations in base case configurations. To facilitate its use, EPA processed BELD6 vegetative cover datasets for the 12US2 and CC4c2 grids for use with BEIS4.

The 2016v2 EMP does not include NO_x emissions from lightning, so DAQ developed its own estimates using a CAMx processor called LNO_x. It uses WRF output fields defining convective activity (cloud top heights and convective available potential energy) to determine the location, timing, and frequency of lightning. The model then uses this information to generate three-dimensional NO_x emissions. LNO_x emissions are developed as virtual point sources over the 12US2 grid. Because lightning is a grid-independent point source (i.e., it does not occur in a set location), LNO_x simulated emissions into both the 12US2 and CC4c2 grids. The use of 12-km LNO_x emissions within the CC4c2 grid does not materially affect CC4c2 ozone results because LNO_x emissions are sparse in time and space.

DAQ also used the 2016v2 EMP to estimate 2023 emissions, with some exceptions. For biogenic emissions, fires (i.e., wildfires, prescribed burns, and agricultural burning), and LNO_x emissions, DAQ assumed that emissions were constant from 2016 through 2023. For aviation emissions, DOA provided 2023 projected emissions for commercial aviation; NAFB provided 2022 emissions, which DAQ projected to 2023. DAQ processed both commercial and federal aviation emissions from aircraft operations with SMOKE.

Table 7 shows the total county-wide emissions used in the attainment modeling demonstration. Section 6 of Attachment B provides information on the modeled emissions inventory.

Table 7. July Weekday Average Clark County 2016 and 2023 Anthropogenic NO_x and VOC Emissions by Sector

Source Category	2016 NOx (tpd)	2023 NOx (tpd)	2016 VOC (tpd)	2023 VOC (tpd)
Point source	14.6	9.7	2.1	1.8
Nonpoint source	4.0	4.1	57.0	60.8
On-road mobile	48.7	20.2	27.8	17.7
Non-road mobile	42.4	24.5	29.5	27.6
Airports (commercial & federal)	12.7	16.6	2.3	3.1
Locomotives	1.3	1.1	0.1	0.0
Fires	0.0	0.0	0.3	0.3
Total	**123.7**	**76.2**	**119.1**	**111.3**

4.3.6 Model Refinement

After preparing all the inputs for the model, DAQ ran a 2016 base case scenario to determine the model's suitability for the attainment demonstration. Due to a variety of factors (outlined in Attachment B), DAQ found that the base case model was insufficient to support regulatory analyses for the attainment demonstration. DAQ proceeded to conduct a series of additional sensitivity tests (SENS1-6), comparing changes in modeled responses to measured ozone concentrations. The following updates improved model performance:

- Elevating landing/takeoff operation emissions from Harry Reid International Airport to reduce the large NO_x burden in central Las Vegas;
- Including aerosols and related chemistry so the full effect from wildfires and large urban pollution plumes were properly characterized throughout the modeling domain;
- Using the BEIS4/BELD6 model on the 36US3, 12US2, and CC4c2 grids to replace the original BEIS3.7/BELD5 biogenic emissions from the 2016v2 EMP; and
- Applying an alternative set of 36US3 initial/boundary conditions derived from 2016 CAM-chem global chemistry model results.

The final sensitivity analysis ("Base2" in Attachment B) improved model performance in replicating ozone patterns from May through June while maintaining the same level of good performance for July and August; however, the model showed a tendency to overpredict ozone on non-peak days while continuing to underpredict ozone on the highest peak days. Also, the influence of biogenic emissions on desert environment conditions introduces a high level of uncertainty whether any of the biogenic models reliably estimate rural and urban VOC emissions within the Las Vegas Valley. Nonetheless, DAQ believes that ozone production from biogenic emissions in the desert environment are likely minimal given the very low isoprene concentrations measured during a 2021 field study (NOAA 2022).

The model underpredicted all of the 26 highest observed ozone days (exceeding 70 ppb) during the summer of 2016, with 8 days within 5 ppb and an average underprediction of approximately 10 ppb. Considering all high days, the average peak observation was 75.4 ppb versus an average paired prediction of 64.2 ppb in the final base case (absolute and normalized bias of -11.2 ppb and -15%, respectively). Results were similar when considering only days not influenced by wildfires. On those 15 days, the average peak observation was 74.2 ppb versus an average paired prediction of 64.4 ppb in the final base case (absolute and normalized bias of -9.8 ppb and -13%, respectively).

Comparing modeled values against the measured design value at each monitoring site shows that, even though the model underpredicted ozone concentrations on the highest ozone days, CAM_x performs well in the modeled spatial pattern of high and low ozone concentrations. Therefore, the model adequately replicates the processes that form and disperse ozone throughout the Las Vegas Valley with well-represented relative response factors for days with predicted concentrations greater than 60 ppb. DAQ concluded that the revised model (BASE2) is suitable for use in the attainment demonstration.

4.3.7 Future Year Base Case Modeling

DAQ used the final 2016 base case CAMx configuration to model attainment, using anthropogenic emissions inputs for each of the three modeling grids (36US3, 12 US2, CC4c2) and a model configuration identical to SENS6/BASE2. The 2023 emissions inventory reflected local, state, and national rules currently in effect and total estimated emissions for HA 212 of 103.49 tpd VOC and 66.47 tpd NO_x, which differ from the values in Table 7 because the table reflects emissions for all of Clark County, not just the nonattainment area (HA 212).

EPA has procedures for predicting future design values from modeling results using the modeled attainment test. It provides Software for Model Attainment Test - Community Edition for conducting these procedures and for scaling base year ozone design values to future year values at each monitoring site while considering interannual variability. EPA also allows air pollution control agencies to exclude some exceptional event-like days from modeled design value projections.

Following these procedures, DAQ scaled the 2016 base year ozone design values to 2023 future year ozone design values at each monitoring site. All predicted design values were below the 2015 ozone NAAQS. DAQ determined that four monitors (Joe Neal, Walter Johnson, Paul Meyer, and Green Valley) were critical sites for determining 2023 design value projections based on previous exceedances recorded at each site, with Joe Neal showing the highest predicted design value for 2023 (69 ppb). See the table in Section 4.2 above for design value predictions without additional control measures for each monitoring station.

4.3.8 Control Measures

In addition to modeling base case future year emissions, DAQ modeled the effect of achieving the required 15% ROP for VOC emissions reductions, which include CTG RACT and additional potential local control measures (i.e., Consumer Products and Architectural Industrial Maintenance Coatings rules) on future design value projections. Implementation of these control measures lowered the projected design values at the monitoring stations by 0-0.4 ppb from the 2023 future base case discussed in Section 4.3.7. See Table 5 in Section 4.2 for design value predictions with additional control measures for each monitoring station.

As modeled, a 15% ROP in 2023 included 19.42 tpd of VOC emissions reductions from the 2017 base year VOC inventory, which reflected 4.29 tpd of VOC emissions reductions from existing local and federal control measures, 5.69 tpd of VOC emissions reductions from CTG RACT regulations, and 9.44 tpd of VOC emission reductions from additional local control measures.[5] As Table 8 shows, total existing emissions reductions plus additional local control measures were modeled as a net 18% of VOC emissions reduction compared to the 2017 base year emission inventory; however, this analysis does not reflect the ROP reductions in Section 8 proposed for implementation in 2026.

5 DAQ completed this modeling before updating the emissions inventory for use in the ROP analysis, which is why the modeled emissions reductions and the calculated emissions reductions to meet ROP differ. The difference is not material to the attainment demonstration modeling, which models attainment without these control measures.

Table 8. HA 212 2017 and 2023 VOC Emissions (tpd) by Sector, Emission Reductions by Control Measure, and Net Change in Emissions from 2017–2023 for 15% ROP Scenario

Description	2017	2023	Difference	Percent Difference
VOC Emissions by Sector				
Point source	1.25	1.32	0.07	5.6%
Nonpoint source	56.05	58.29	2.24	4.0%
Onroad mobile	24.43	17.01	-7.42	-30.4%
Nonroad mobile	24.03	24.17	0.14	0.6%
Airports (commercial & federal)	1.94	2.62	0.68	35.1%
Locomotives	0.04	0.03	-0.01	-25.0%
Subtotals	*107.73*	*103.44*	*-4.29*	*-4.0%*
RACT VOC Emission Reductions				
Solvent Metal Cleaning (Degreasers)		0.66		
Graphic Arts		1.43		
Cutback Asphalt		0.78		
Industrial Cleaning Solvents		2.82		
Subtotals		*5.69*		
VOC Emission Reductions for Planned Local Control Measures				
Consumer Products OTC Model Rules Phase IV		6.74		
AIM Coatings OTC Model Rules Phase II		2.70		
Subtotals		*9.44*		
Net VOC Emissions				
Totals	**107.73**	**88.31**	**-19.42**	**-18.0%**

To simulate these emissions reductions, DAQ reduced nonpoint solvent sector emissions in the 2023fj emissions inventory, assuming all reductions from CTG RACT occurred within HA 212 and the additional local control measures occurred throughout Clark County. DAQ repeated the 2023 future year base case CAMx run, but replaced 2023 nonpoint solvent sector emissions on the CC4c2 grid with revised emissions that reflected reductions from control measures. No other inputs were modified, and DAQ ran only the 12US2/CC4c2 two-way nested grids using the 2023 12US2 future base case boundary conditions extracted from the 36US3 grid.

The revised modeling continues to show HA 212 in attainment by the attainment date, with a high design value of 68.8 ppb at the Joel Neal monitoring station.

5.0 CONTROL STRATEGY

The 2015 Ozone NAAQS Implementation Rule requires areas classified as "moderate nonattainment" to submit an attainment demonstration that provides for emissions reductions (i.e., a control strategy) as necessary to attain the NAAQS by the attainment date (40 CFR Part 51.1308(a)). All control measures needed for attainment must be implemented as expeditiously as practicable, but no later than the beginning of the ozone season in the attainment year (83 FR 63033–63034).

A control strategy is the suite of existing and future control measures leading to permanent and enforceable emissions reductions that DAQ will implement in the nonattainment area to comply with national, regional, state, and local regulations. The attainment demonstration modeling analysis evaluated the potential effects of existing control measures and demonstrated that no additional control measures are needed to achieve timely attainment for the HA 212 nonattainment area by the August 3, 2024, attainment date.

Specifically, DAQ's attainment demonstration model predicts that future 2023 base case design values, without additional control measures, are below 70 ppb at all monitoring stations. The highest predicted three-year design value is 69.0 ppb at Joe Neal. Table 9 displays projected design values.

Table 9. 2023 Predicted Future Design Values Based on Existing Control Measures

Monitoring Site ID	Site Name	2023 Modeled Design Value (ppb) With Existing Control Measures (base case)
320030022	Apex	65.2
320030023	Mesquite	57.2
320030043	Paul Meyer	67.7
320030071	Walter Johnson	67.9
320030073	Palo Verde	67.2
320030075	Joe Neal	69.0
320030298	Green Valley	67.3
320030540	Jerome Mack	64.1
320030601	Boulder City	61.5
320031019	Jean	63.9
320032002	J.D. Smith	67.3
320037772	Indian Springs	62.3

The source apportionment study showed that 13 ppb (19%) of the modeled design value is attributable to international pollution, while local emissions contribute only 11 ppb (16%) to the 69.0 ppb modeled design value. Nevertheless, DAQ intended to implement six additional control measures to meet its CTG RACT and 15% ROP attainment plan requirements. These control measures would have resulted in reductions in the nonpoint solvent sector of the 2023fj EMP emissions inventory and, in some cases, led to further reductions in modeled design values. Table 10 shows that modeled outcomes from implementing these six additional control measures display only slight (0–0.4 ppb) decreases in modeled design values. As required by the Act and to meet its CTG RACT and 15% ROP attainment plan requirements, DAQ implemented a total of 10 control measures, as described in Section 8.

Table 10. Predicted Design Value Following Implementation of CTG RACT and 15% ROP

Monitoring Site ID	Site Name	Design Value After CTG RACT +15% VOC ROP (ppb)	Differences from 2023 Base Case (ppb)
320030022	Apex	65.2	0.0
320030023	Mesquite	57.2	0.0
320030043	Paul Meyer	67.5	-0.2
320030071	Walter Johnson	67.5	-0.4
320030073	Palo Verde	66.9	-0.3
320030075	Joe Neal	68.8	-0.2
320030298	Green Valley	67.1	-0.2
320030540	Jerome Mack	64.0	-0.1
320030601	Boulder City	61.5	0.0
320031019	Jean	63.9	0.0
320032002	J.D. Smith	67.1	-0.2
320037772	Indian Springs	62.2	-0.1

This section outlines the existing, permanent, and enforceable control requirements that form DAQ's control strategy for the HA 212 nonattainment area and describes additional controls that will apply after the attainment date.

5.1 FEDERAL CONTROLS

EPA has adopted several national rules that do or will require VOC and NO_x emissions reductions from stationary and mobile sources. These rules provide emissions reductions between 2017 (base year) and 2024 (attainment year), which will provide ambient air quality benefits in HA 212.

5.1.1 Tier 3 Emission Standards for Vehicles and Gasoline Sulfur Standards

In April 2014, EPA finalized the Tier 3 Motor Vehicle Emissions and Fuel Standards Rule, which required production of cleaner vehicles and lower-sulfur fuel. The rule, which phases in between 2017 and 2025 (79 FR 23414), will reduce emissions from passenger cars, light-duty trucks, medium-duty passenger vehicles, and some heavy-duty vehicles. Tier 3 requires all passenger vehicles to meet an average standard of 0.03 gram/mile of NO_x. These standards for light-duty vehicles are expected to reduce NO_x and VOC emissions by approximately 80% nationwide. Tier 3 also includes evaporative standards using onboard diagnostics that will reduce VOC emissions by 50% compared to Tier 2 requirements (81 FR 23417).

5.1.2 Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements

In January 2001, EPA issued a final rule for highway heavy-duty engines, a program that includes low-sulfur diesel fuel standards requiring reductions beginning in 2004 (66 FR 5002). This rule applies to heavy-duty gasoline and diesel trucks and buses. Fleet turnover will continue to reduce emissions from these mobile sources, and the MOVES emissions model accounts for continued emissions reductions from this program in future years.

EPA estimates the rule will result in a 40% reduction in NO_x from diesel trucks and buses nationwide. In December 2022, EPA issued a new rule (the "Clean Trucks Plan") that lowered the NO_x standard for heavy-duty engines to 0.035 milligrams/horsepower-hour (hp-h) beginning with model year 2027. Since these emissions reductions occur beyond the attainment date, DAQ did not consider the 2022 rule update in developing its control strategy.

5.1.3 Safer Affordable Fuel Efficient Vehicles Final Rule

In April 2020, EPA and the National Highway Traffic Safety Administration issued a final rule that requires automakers to improve fuel efficiency by 1.5% beginning in model year 2021 and continuing through model year 2026 (85 FR 24174). While the rule targets reductions in CO_2 emissions, it will reduce NO_x and VOC emissions as a co-benefit.

5.1.4 Clean Air Non-Road Diesel Rule

In June 2004, EPA issued the Clean Air Non-Road Diesel Rule (69 FR 38958), which applies to diesel engines used in such industries as construction, agriculture, and mining. It contains a cleaner fuel standard, similar to the highway diesel program. The new engine standards, based on engine horsepower, took effect starting in 2008, but equipment turnover will ensure continued emissions reductions from this category in future years.

5.1.5 Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles – Phase 2

In October 2016, EPA finalized changes to a federal rule to reduce greenhouse gas (GHG) emissions from medium and heavy-duty engines and vehicles (81 FR 73478). The rule sets GHG emissions standards for four regulatory categories of heavy-duty vehicles; it covers model years 2018–2027 for certain trailers, and model years 2021–2027 for semitrailer trucks, large pickup trucks, vans, and all types and sizes of buses and work trucks. Although this rule primarily targets GHG emissions, it will lower NO_x and VOC emissions over time due to fleet turnover.

5.1.6 Revised 2023 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions Standards

In December 2021, EPA finalized changes to existing federal rules to reduce GHG emissions from cars and light trucks, including sport utility vehicles (86 FR 74434). The rule requires GHG emissions reductions starting with model year 2023, which will reduce NO_x and VOC emissions as a co-benefit. This rule applies nationwide and will ensure continued emissions reductions as the vehicle fleet turns over.

5.1.7 Control of Emissions for Nonroad Spark Ignition Engines and Equipment

In October 2008, EPA set emission standards for new nonroad spark ignition engines (73 FR 59034). Starting in 2011 and 2012, exhaust emissions standards apply for different sizes of new land-based, spark-ignition engines at or below 19 kilowatts (kW). These small engines are used primarily in lawn and garden applications, and emissions reductions will continue as engines are replaced.

5.1.8 Reciprocating Internal Combustion Engines Standards

EPA has issued multiple regulations that cover different types of reciprocating internal combustion engines (RICE):

- Existing, new, and reconstructed stationary RICE of 500 hp or more located at major sources (69 FR 33474).
- New and reconstructed stationary RICE located at area sources of HAP emissions, and new and reconstructed stationary RICE with a site rating of 500 hp or less located at major sources of HAP emissions (73 FR 3568).
- Existing stationary compression ignition (CI) RICE with a site rating of 500 hp or less located at major sources, existing nonemergency CI engines with a site rating higher than 500 hp located at major sources, and existing stationary CI RICE of any site rating located at area sources (75 FR 9648).
- Stationary spark ignition RICE located at area sources of HAP emissions, or those with a site rating of 500 brake-hp or less located at major sources of HAP emissions (75 FR 51570).

These regulations will continue to produce emissions reductions as old engines are rebuilt or replaced.

5.1.9 National Volatile Organic Compound Emissions Standards for Consumer Products

In 1998, EPA finalized 40 CFR Part 59, Subpart C under Section 183(e) of the Act. The rule requires manufacturers, importers, and distributors to limit the VOC content of consumer products. EPA estimated the final rule would reduce VOC emissions by 90,000 tpy nationwide (63 FR 48819).

5.1.10 Control of Hazardous Air Pollutants from Mobile Sources

This rule, also known as the Mobile Source Air Toxics (or MSAT2) Rule, requires refiners and importers to produce gasoline with an annual average benzene content of 0.62 volume percent or less beginning in 2011 (72 FR 8428; 73 FR 61358). EPA estimates that by 2030 this rule will have reduced total mobile source air toxics emissions by 330,000 tons and VOC emissions by over 1 million tons.

5.1.11 Emissions Standards for Locomotive Engines

On June 30, 2008, EPA promulgated regulations to reduce NO_x emissions from locomotive engines (73 FR 37096). The controls apply to all types of locomotives, including line-haul, switch, and passenger. Emissions standards for newly built engines phased in starting in 2009; longer-term standards for newly built locomotives took effect in 2015. EPA projects this rule will continue to reduce NO_x emissions through 2030.

5.1.12 NO_x Emission Standard for New Commercial Aircraft Engines

On June 18, 2012, EPA adopted emission standards for aircraft gas turbine engines with rated thrusts greater than 26.7 kilonewtons (77 FR 36342), used in commercial passenger and freight aircraft. The rule includes two new tiers of NO_x emissions standards, referred to as Tier 6 standards and Tier 8 standards. The Tier 6 standards became effective for newly manufactured aircraft engines beginning in 2013. EPA projected cumulative NO_x reductions associated with these standards to be about 100,000 tons from 2014 to 2030 (77 FR 36346).

5.2 EXISTING STATE CONTROL MEASURES

5.2.1 NRS 445B.780, Heavy-Duty Vehicle Program

NDEP and the Nevada Department of Motor Vehicles (DMV) jointly developed this rule to reduce motor vehicle-related pollution by limiting excessive tailpipe or smokestack emissions from any gasoline- or diesel-powered vehicle with a manufacturer's gross vehicle weight rating (GVWR) of 14,001 pounds (lb) or more.

Heavy-duty vehicles are pulled over for random roadside testing to determine if the exhaust from their vehicle exceeds state opacity standards. Violators are notified, and required to repair and retest the vehicle within 30 days. Fleets may request opacity testing in their fleet yard; if violations are found, fleet managers are notified and vehicles voluntarily repaired and retested.

5.2.2 NRS 445B.700-835, Inspection and Maintenance Program

NDEP and the Nevada DMV jointly developed this rule, administered by the DMV, to control vehicle emissions. The rule reduces motor vehicle-related NO_x and VOC through vehicle inspection and emissions-related repair. Emissions testing is required annually in Clark County before renewing a vehicle’s registration. All gasoline-powered vehicles must be tested (with limited exceptions), as well as diesel-powered vehicles weighing up to 14,000 lb GVWR.

5.3 EXISTING LOCAL CONTROL MEASURES

5.3.1 AQR Section 0, “Definitions”

This section defines key terms used throughout the AQRs. DAQ amended it to include definitions for implementing new local control measures, which are discussed in Section 5.4.

5.3.2 AQR Section 12.0, “Applicability and General Requirements for Permitting Stationary Sources”

This section contains applicability and general requirements for permitted stationary sources. DAQ amended it to include a requirement for permitting a stationary source that is subject to a SIP regulation, requiring the source to obtain a minor source permit.

5.3.3 AQR Section 12.1, "Permit Requirements for Minor Sources"

This section requires all minor stationary sources to obtain a permit to construct and operate if they have the potential to emit 5 tpy or more of VOC or NO_x. Some emissions units at these minor stationary sources must comply with RACT requirements.

As part of this attainment plan, DAQ amended AQR Section 12.1 to revise definitions relevant to the implementation of new local control measures, which are discussed in Section 5.4. DAQ added a requirement to obtain a minor source permit if another AQR requires the stationary source to obtain that permit. AQR Section 102, which regulates gasoline dispensing facilities in Clark County, requires certain owners or operators to obtain a minor source permit. DAQ added a requirement that minor stationary sources located within a nonattainment area may be subject to additional requirements imposed to reduce the targeted pollutant(s).

AQR Section 12.11 requires owners or operators of a minor source that is a member of a specific source class and is subject to the permit requirements of AQR Section 12.1 to obtain an authority to operate under a general permit issued by the Control Officer.

5.3.4 AQR Sections 12.3–12.5, Addressing Permit Requirements for Stationary Sources

These sections require all major stationary sources to obtain a permit to construct and operate. AQR Section 12.3 requires some stationary sources in HA 212 to comply with the more stringent lowest achievable emission reduction (LAER) requirement. AQR Section 12.4 requires some emission units to comply with RACT requirements. AQR Section 12.5 collects the requirements of the previous two sections into an operating permit.

5.3.5 AQR Section 28, "Fuel Burning Equipment"

This section applies to fuel burned for the primary purpose of producing heat or power by indirect heat transfer. It regulates the burning of coke, coal, lignite, coke breeze, fuel oil, and wood, but not refuse. The regulation targets reductions in PM_{10} emissions, but by promoting good combustion practices, the rule produces NO_x and VOC emissions reduction co-benefits.

5.3.6 AQR Section 42, "Open Burning"

This section prohibits open burning except as expressly authorized by the Control Officer. It particularly prohibits opening burning during ozone events.

5.3.7 AQR Section 50, "Storage of Petroleum Products"

This section applies to tanks, reservoirs, and containers with a volume capacity greater than 40,000 gallons. It reduces VOC emissions by prohibiting storage of compounds with a vapor pressure greater than 78 millimeters of mercury (mm Hg) unless the emissions unit is pressurized, includes a floating roof, or uses a vapor recovery system. DAQ added AQR Sections 13.3 and 14.2 to incorporate by reference one NESHAP subpart and five NSPS subparts that will replace AQR Sections 50 and 51 to improve rule effectiveness by promoting consistency and thoroughness in compliance obligations.

5.3.8 AQR Section 51, "Petroleum Product Loading into Tanks, Trucks and Trailers"

This section reduces VOC emissions by prohibiting loading of petroleum products with a vapor pressure exceeding 78 mm Hg unless the facility is designed for bottom loading only or uses a submerged fill tube. Loading must occur under a vapor-tight seal with a vapor collection system. DAQ amended Sections 13.3 and 14.2 to incorporate by reference one NESHAP subpart and five NSPS subparts that will replace AQR Sections 50 and 51 to improve rule effectiveness by promoting consistency and thoroughness in compliance obligations.

5.3.9 AQR Section 53, "Oxygenated Gasoline Program"

This section reduces NO_x emissions by requiring that all fuel sold between October 1 and March 31 contain at least 3.5% oxygen content by weight to increase combustion efficiency.

5.4 NEW LOCAL CONTROL MEASURES

As part of the moderate area 2015 ozone NAAQS requirements, DAQ will reduce VOC emissions by promulgating new regulations to impose CTG RACT on stationary sources, RACT on major sources, and additional measures to satisfy ROP requirements. Once approved by EPA, the Nevada SIP will include the following new regulations:

- AQR Section 101, "VOC Emissions Control for Industrial Adhesive Operations."
- AQR Section 102, "Gasoline Dispensing Facilities."
- AQR Section 103, "VOC Emissions Control for Miscellaneous Metal or Plastic Parts Coating Operations."
- AQR Section 104, "VOC Emissions Control for Industrial Cleaning Solvent Operations."
- AQR Section 105, "VOC Emissions Control for Metal Solvent Degreaser Operations."
- AQR Section 106, "VOC Emissions Control for Offset Lithographic, Letterpress, and Flexible Package Printing and Other Graphic Arts Operations."
- AQR Section 107, "VOC Emissions Control for Cutback Asphalt Manufacturing and Use."
- AQR Section 13, "National Emission Standards for Hazardous Air Pollutants," with AQR Section 13.3 incorporating by reference 40 CFR Part 63, Subpart BBBBBB.
- AQR Section 14, "New Source Performance Standards," with AQR Section 14.2 incorporating by reference 40 CFR Part 60, Subparts K, Ka, Kb, XX, and XXa.
- AQR Section 121 (currently in development) addressing existing major source RACT.
- AQR Section 130, "VOC Emissions Control for Architectural and Industrial Maintenance Coatings."

These rules are summarized below and discussed in greater detail in Sections 7 and 8.

5.4.1 AQR Sections 13, 14, and 101–107 (CTG RACT Rules)

The new regulations will impose at least EPA's presumptive RACT level of control on owners and operators of stationary sources with regulated operations, which will result in a 7.5% VOC emissions reduction from the 2026 ROP emissions inventory (7.75 tpd of VOC). These emissions reductions will occur after the August attainment date.

AQR Sections 101–107 are generally structured alike, with similar applicability provisions. AQR Section 107 will apply throughout Clark County. AQR Sections 101–106 will apply to owners or operators of stationary sources with certain specified operations when that source is located in an area EPA has designated as ozone nonattainment and has classified as moderate or higher after January 5, 2023, the date EPA published the notice classifying HA 212 as a moderate ozone nonattainment area. These regulations will continue to apply to stationary sources in such area even after EPA redesignates the area to attainment, i.e., they will still apply during the maintenance period. In addition, AQR Sections 13.3 and 14.2 will become federally enforceable in all areas of Clark County after they are incorporated into the SIP.

AQR Sections 101 and 103–106 have similar applicability thresholds: stationary sources with projected maximum emissions of VOC from specified operations equal to or greater than 3.0 tons per calendar year must meet specific emissions standards and work practice requirements; stationary sources with emissions below this threshold must meet work practice requirements only. Rule applicability is based on total calendar year emissions, from the beginning of January to the end of December. Owners or operators of these sources are not required to calculate a rolling 12-month total of emissions.

Applicability thresholds for AQR Sections 102 and 107 are structured differently. AQR Section 102 applies to all gasoline dispensing facilities (GDFs), though it provides for exemptions based on throughput. AQR Section 107 (cutback asphalt operations) has the same applicability threshold as the other 100 series rules—based on projected maximum emissions of VOC equal or greater than 3.0 tons per calendar year—but requires the owner or operator to compare maximum emissions from all worksites to the threshold, rather than from a single stationary source. A worksite includes any location in Clark County where asphalt is manufactured, sold, mixed, used, and/or stored by the same owner or operator. The applicability of AQR Section 107 extends beyond the boundaries of HA 212 to assure the rule remains equally as or more stringent than the existing SIP-approved regulation AQR Section 60.4. AQR Section 107 will replace AQR Section 60.4 in the SIP.

In AQR Sections 13.3 and 14.2, DAQ adopted through incorporation by reference EPA's federal NSPS regulations in 40 CFR Part 60, Subparts K, Ka, Kb, XX and XXa and its NESHAP regulations in 40 CFR Part 63, Subpart BBBBBB. These regulations meet or exceed the presumptive RACT requirement for bulk gasoline plants and terminals, petroleum storage, and associated equipment leaks. Along with the incorporation of these regulations and AQR Section 102, DAQ requests the removal of AQR Sections 50–52 and 60.1 from the SIP because the newly incorporated rules are at least as stringent as the existing rules, and removal of the rules provides an opportunity to streamline compliance obligations under the more thorough requirements in the federal rules.

All owners or operators subject to AQR Sections 101 and 103–107 will have to meet registration, notification, recordkeeping, and reporting requirements, as applicable. Owners or operators subject to AQR Section 102 must comply with registration requirements unless the GDF is required to obtain a stationary source permit. AQR Sections 101 and 103–107 generally provide existing owners or operators six months to submit registrations and begin complying with the emissions standards and work practice requirements; however, owners or operators electing to install a new emissions control system (ECS) must comply no later than 18 months after the effective date of the rule. New sources must comply with emission standards upon beginning normal operations, and with registration requirements within 45 days after becoming subject to the regulation. Existing sources that become newly subject to the rule after the first compliance date must comply upon meeting the applicability threshold.

Some activities are exempt under the rules; these exemptions are tailored to specific types of equipment in each individual rule. Also, operations that use less than 500 gallons (5,000 lb in AQR Section 106) of materials per calendar year are exempt from Sections 101 and 103–106.

AQR Section 102 has different compliance dates than the other rules, which are included in individual provisions in the emissions standards rather than gathered into a single compliance date section. Some provisions are immediately effective because AQR Section 102 is intended to replace existing SIP-approved regulation AQR Section 52, which already requires compliance with some of these provisions. Other AQR Section 102 provisions allow up to one year to comply.

The new sections that set minimum VOC content requirements on materials allow an owner or operator to continue to use existing material inventory until 12 months after the effective date of the rule or 12 months after first becoming subject to the rule, whichever is later. During this time, an owner or operator may use existing material inventory without complying with the emissions standards but may not purchase new, non-compliant material without using a compliant ECS. The two exceptions are AQR Section 101, which allows a total volume of less than 55 gallons per calendar year of noncomplying materials, and AQR Section 106, which allows a total volume of 110 gallons per calendar year of noncomplying cleaning materials in offset lithographic and letterpress printing operations.

AQR Sections 101 and 103–107 also provide the Control Officer with the flexibility to establish a different compliance date for individual stationary sources, though it cannot exceed three years from the rule’s effective date. The Control Officer can use this flexibility when the owner or operator demonstrates, through a permit application, that they cannot comply with the rules by the applicable compliance date: for example, there may be valid delays in engineering, purchasing, or installing an ECS that would extend final operation beyond the 18 months provided to comply. The Control Officer may extend or deny a compliance date extension request through permitting procedures (i.e., minor source permit, authority to construct, or Part 70 operating permit revisions), but DES expects these instances to be few (if any).

There are no provisions for requesting a compliance date extension under AQR Section 102. DAQ has determined that the compliance dates are reasonable because GDFs must already comply with some requirements and can readily bring other equipment into compliance by the specified dates.

5.4.2 AQR Section 121 (Existing Major Source RACT)

AQR Section 121 will provide emissions standards that implement major source RACT requirements. This regulation, which will apply to major sources of VOC and/or NO_x, will require stationary sources to meet specific emissions limitations for different types of equipment or submit a permit application to obtain a source-specific RACT determination.

To develop the specific emissions limitations that will apply to the eight existing major sources in HA 212, these sources voluntarily submitted information from which DAQ made case-by-case RACT determinations. Attachment D documents the information submitted, and will serve as the technical support document for the emissions standards in AQR Section 121. Section 7.2 of this plan includes more information on the case-by-case RACT process and DAQ's conclusions.

After completing the major source RACT determination process, DAQ noted commonalities in the control requirements between the eight major sources. Thus, DAQ opted to codify major-source RACT requirements in AQR Section 121, rather than submit individual permits for inclusion in the SIP. Any variation from this rule that is allowed through a future case-by-case RACT determination if HA 212 were reclassified would be subject to public and EPA review and documented in an authority to construct or Part 70 operating permit.

The emissions standards in AQR Section 121 will represent current major-source RACT requirements for specific types of equipment.

5.4.3 AQR Section 130, "VOC Emissions Control for Architectural and Industrial Maintenance Coatings"

DAQ adopted this regulation to control the VOC content in architectural and industrial maintenance (AIM) coatings, including paint, primers, varnishes, or lacquers, as well as solvents used as thinners and for cleanup. DAQ based its rule on the OTC model rule (Phases I–II), which recommends reducing VOC emissions by regulating the VOC content of AIM coatings sold, supplied, offered for sale, applied, solicited for the application of, or manufactured for use in Clark County.

The term "architectural coating" refers to a coating applied to such things as stationary structures, portable buildings, pavements, and curbs. This rule will not apply to (1) coatings applied in shop applications or to nonstationary structures (e.g., airplanes, ships, boats, railcars, automobiles), (2) adhesives, and (3) containers of 1 liter (L) or less. DAQ anticipates a 3.83 tpd VOC emissions reduction from implementing this control measure.

5.5 WITHDRAWAL AND REPLACEMENT OF EXISTING CONTROL MEASURES

AQR Sections 50–52 and 60, four of Clark County's existing SIP-approved regulations, partly overlap with the applicability of several of the county's new local control measures and federal rules incorporated by reference. After the BCC repealed Sections 52 and 60 in 2011, they were no longer part of the AQRs, but they remained part of the approved SIP. As part of this SIP submission, DAQ requests that EPA withdraw these outdated and duplicative regulations from the approved SIP and replace them with the new local control measures and federal rules incorporated by reference.

Before EPA can approve a state's SIP submission into the State Plan, it must follow the procedures for plan revisions in Section 110(l) of the Act. The Administrator may not approve a plan revision "if the revision would interfere with any applicable requirement concerning attainment and reasonable further progress (as defined in Section 171), or any other applicable requirement of the Act" (42 U.S.C. 7410). In nonattainment areas, EPA must also assure the revision satisfies the requirement in Section 193 of the Act stating that control requirements in effect before the 1990 amendments may be only modified if "equivalent or greater emissions reductions" are achieved (42 U.S.C. 7515). The U.S. Court of Appeals for the Ninth Circuit interpreted these provisions as requiring EPA to perform a wholistic look "of an overall plan capable of meeting the Act's attainment requirements… [in] 'relation of the step to the movement as whole'" (*Hall v. EPA*, 273 F.3d 1146 (9th Cir. 2001)).

The court found that a rule-to-rule comparison of emissions reduction was not adequate to show that new rules met current-day SIP obligations. For EPA to approve revisions to existing plan requirements, the submitted SIP revisions must be "neutral in their effect on RFP…" (EPA 2010), as upheld by *Natural Res. Def. Council v. Jackson*, No. 09-1405 & 10-2123 (7th Cir. 2011). These decisions did not mandate a line-by-line comparison of each withdrawn regulation to a corresponding new regulation; rather, EPA must determine whether DAQ's requested SIP revision, as a whole, meets the Act's requirements, and approve the revision if the new control measures will not interfere with HA 212's progress toward attainment or result in fewer emissions reductions.

The CTG RACT analysis and the 15% ROP Plan provide a detailed estimate of emissions reductions that will result from the new CTG RACT rules (11.57 tpd), far greater than the reductions Sections 50–52 and 60 could achieve. As discussed in this section, the existing rules lack control effectiveness because they lack clarity, compliance assurance provisions, and an authority to implement. Their proposed replacements, when directly compared, provide at least equal or greater emissions reductions. The SIP submission as a whole, including the new additional control measures, assures additional benefits that make the requested SIP revision more than neutral in reducing ambient ozone concentrations in HA 212. (Section 4.3.8 details the ozone benefits from modeled local control measures.)

The attainment demonstration in Section 4 explains that additional local measures, including the nine adopted CTG RACT rules, are not necessary to demonstrate attainment for HA 212. In the 2016v2 EMP, EPA did not include Sections 52 or 60 as control measures in estimating the Clark County 2017 NEI—yet DAQ still modeled attainment with the NAAQS. This means that the modeled inventory used in the attainment demonstration did not rely on the control measures in those two sections to demonstrate attainment. Accordingly, the attainment demonstration shows that withdrawing these rules from the SIP will not interfere with RFP or attainment of the NAAQS.

DAQ asks EPA to fully approve the request to withdraw the Clark County SIP-approved regulations AQR Sections 50–52 and 60.1–60.4 from the SIP.

5.5.1 Replacement of AQR Section 50

AQR Section 50 requires that 40,000-gallon or larger tanks storing petroleum liquid with a vapor pressure of 78 mm Hg or greater be equipped with a vapor recovery system or floating roof unless the tank is pressurized. The rule includes provisions for reducing equipment leaks, although requirements such as double seals are not included. DAQ will replace this rule in the SIP by incorporating

EPA's NSPS federal rules at 40 CFR Part 60, Subparts K, Ka, and Kb, and its NESHAP rule at 40 CFR Part 63, Subpart BBBBBB.

Although there are some differences in applicability of the federal rules and the AQRs, DAQ determined that collectively incorporating by reference all the federal rules fills the potential gaps left by any individual federal rule. For example, although Subpart Kb exempts bulk gasoline plants from its requirements, Subpart BBBBBB regulates these tanks with requirements more stringent than the AQRs; and while Subpart BBBBBB exempts aviation fuel loading at airports, DAQ will regulate these activities under the new AQR Section 102.

DAQ determined that EPA's federal rules collectively represent the most current assessment of emissions control capabilities to meet the best available system of emissions reduction under Section 111 of the Act and the maximum achievable control technology under Section 112 of the Act. These regulatory standards exceed the statutory requirement for CTG RACT. The federal rules are written more clearly than AQR Section 50, and include more comprehensive compliance obligations. Table 11 shows how the federal rules are as (or more) stringent than the control requirements in AQR Section 50 and meet presumptive RACT for the CTG source category.

Table 11. Comparison of Federal Rules to AQR and Presumptive RACT

Construction or Reconstruction Date	40 CFR Citation	Requirement	General Exemptions	Comparison with AQR 50	Comparison with CTGs
3/6/74-5/19/78	60.112L: Storage Vessel	If true vapor pressure of ≥ 78 mm Hg (1.5 psia) but ≤ 570 mm Hg (11.1 psia): equip with floating roof, vapor recovery system, or equivalent.	Storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.	Meets AQR 50.1 applicability threshold and control & vapor pressure requirements; exemption not relevant to HA 212.	Meets or exceeds internal or external floating roof and seal requirement; presumptive RACT includes similar exemption.
6/11/73-5/19/78		If true vapor pressure of the petroleum liquid > 570 mm Hg (11.1 psia): equip with vapor control system or equivalent.			
5/19/78-7/23/1984*	60.112a: Storage Vessels	If true vapor pressure of ≥ 10.3 kPa (1.5 psia) but ≤ 76.6 kPa (11.5 psia): equip with external floating roof meeting specs, fixed roof with internal floating roof meeting specs, or vapor recovery system.	Each petroleum liquid storage vessel < 1,589,873 L (420,000 gal) used for petroleum or condensate stored, processed, or treated before custody transfer to unaffected facility.	Meets AQR 51.1 applicability threshold, vapor pressure, and control requirements.	Meets or exceeds internal or external floating roof and seal requirement; presumptive RACT includes similar exemption.
		If true vapor pressure of petroleum liquid > 76.6 kPa (11.1 psia): equip w/vapor recovery system meeting 95% reduction by weight.			
7/24/84 and after	60.112b: Storage Vessel	Vessel either with design capacity ≥ 151 m^3 (39,890 gal) containing a VOL with max true vapor pressure ≥ 5.2 kPa but < 76.6 kPa, or with design capacity ≥ 75 m^3 but < 151 m^3 containing a VOL with max true vapor pressure ≥ 27.6 kPa but < 76.6 kPa: equip with fixed roof and internal floating roof, external floating roof, or closed vent system with control device w/95% efficiency.	Capacity ≥ to 151 m^3 storing a liquid with a maximum true vapor pressure < 3.5 kPa or with a capacity ≥ 75 m^3 but < 151 m^3 storing a liquid with a maximum true vapor pressure < 15.0 kPa.	More stringent than AQR 50 applicability and control requirements. AQR does not exempt bulk gasoline plants; these tanks will be regulated under Subpart BBBBBB.	Meets or exceeds presumptive RACT controls, but do not discuss exemption for bulk gasoline plants.

Construction or Reconstruction Date	40 CFR Citation	Requirement	General Exemptions	Comparison with AQR 50	Comparison with CTGs
		Design capacity > 75 m^3 containing VOL with max true vapor pressure > 76.6 kPa: equip with closed vent system and 95% control or equivalent.	Vessels located at bulk gasoline plants; vessels at gasoline service stations; vessels subject to Part 63, Subpart GGGG.	Equivalent to AQR 50 applicability and more stringent by specifying control efficiency of vapor control system. Although AQR does not exempt bulk gasoline plants, these tanks will be regulated under Subpart BBBBBB.	
None	63.11086: Bulk Gasoline Plant Loading Tanks and Trucks	If > 250 gallon, load tank or truck using submerged fill that meets specifications by date installed; all tanks, minimize gasoline spills and follow other work practices such as monthly leak inspection.	Gasoline storage tanks used only for dispensing gasoline in a manner consistent with tanks located at a gasoline station are not subject to any of the requirements in this subpart. These tanks must comply with Subpart CCCCCC.	Meets AQR 51.1.1 requirement to use submerged fill requirement.	Meets presumptive RACT control Option 1.
	63.11087 & Table 1: Bulk Gasoline Terminal Storage Tanks	If gasoline storage < 75 m^3 or < 151 m^3 and throughput < 480 gal/day, equip with fixed roof and set pressure relief valves to > 18 inches of water.	Aviation fuel loading at airports, marine tank loading,	Exceeds AQR 50.1 40,000-gal applicability threshold and imposes controls not required by AQR 50. AQR does not exempt airports, but airports will be regulated under AQR 102. Marine tank loading exemption not relevant to HA 212.	Not covered by presumptive RACT–below applicability threshold.

Construction or Reconstruction Date	40 CFR Citation	Requirement	General Exemptions	Comparison with AQR 50	Comparison with CTGs
	63.11087 and Table 1: Bulk Gasoline Terminal Storage Tanks	If gasoline storage tank ≥ 75 m^3, equip with closed vent system with 95% control by weight, internal floating roof, or external floating roof; surge control tanks fixed roof with pressure vacuum vent with pressure ≥ 0.5 inches of water.	Bulk gasoline terminal not subject to control in Part 63, Subparts R or CC (Subpart R includes equation for exemption, looks like CTG tanks all would be covered by Subpart CC).	Exceeds AQR 50.1 40,000-gal applicability threshold; requires controls exceeding AQR 50 by specifying a control efficiency for the vapor collection system.	Exceeds presumptive RACT control level.

The replacement of AQR Section 50 with the federal rules satisfies the anti-backsliding provisions in Sections 110(l) and 193 of the Act because the federal rules are at least as stringent, and adopting them will improve rule effectiveness by consolidating regulatory compliance obligations under the more detailed compliance demonstration requirements of the federal regulations. Accordingly, the federal rules will not relax the SIP. DAQ asks EPA to replace AQR Section 50 with the federal rules incorporated by reference into the AQRs.

5.5.2 Replacement of AQR Section 51

AQR Section 51 regulates some bulk gasoline plants and all bulk gasoline terminals, and requires these facilities to use submerged (bottom-filling) or vapor collection and disposal, or an equivalent that meets a 90% control efficiency, depending on the facility's annual throughput. DAQ will incorporate the federal NSPS at 40 CFR Part 60, Subparts XX and XXa, and the federal NESHAP at 40 CFR Part 63, Subpart BBBBBB to meet CTG RACT requirements and replace AQR Section 51.

Table 12 displays the general control requirement(s) of the NSPS and NESHAP that DAQ will adopt into the SIP to meet RACT, and shows how the rules meet the existing requirements of AQR Section 51 and are as least as stringent as EPA's CTG presumptive RACT.

Table 12. Comparison of Federal Rules to AQR and Presumptive RACT

Regulation	Affected Source	Construction or Reconstruction Date	40 CFR Citation	Requirement	General Exemptions	AQR Sections 51 & 60.1 Comparison	CTGs Comparison
Part 60, Subpart XX: Bulk Gasoline Terminals	All the loading racks at a bulk gasoline terminal (> 75,700 L/day gasoline or 20,000 gal/day	12/17/80-6/10/22	60.502: Bulk Gasoline Terminal Loading Rack	Exceeds 90% control efficiency in 51.4. Equip with a vapor tight vapor collection system designed to collect		Exceeds 90% control efficiency in 51.4 for new sources, and is roughly equivalent	Meets or exceeds 80 mg/L presumptive RACT.

Regulation	Affected Source	Construction or Reconstruction Date	40 CFR Citation	Requirement	General Exemptions	AQR Sections 51 & 60.1 Comparison	CTGs Comparison
	throughput) which deliver liquid product into gasoline tank trucks.			the total organic compounds vapors displaced from tank trucks during product loading with emissions ≤ 35 mg TOC/liter gasoline loaded, or if equipped with existing system (constructed before Dec 17, 1980) ≤ 80 mg/l.		to control efficiency requirement for existing sources.	
Part 60, Subpart XXa: Bulk Gasoline Terminals	Loading racks at bulk gasoline terminal (> 75,700 gasoline or 20,000 gal/day throughput) that deliver liquid product into gasoline cargo tanks, including gasoline loading racks, vapor collection systems, and vapor processing system.	6/11/22 or after	60.502a: Bulk Gasoline Terminal Loading Rack	Use submerged fill and Equip with vapor tight vapor collection system to collect vapors from cargo tanks during loading. New units: Use thermal oxidizer to reduce emissions to < 1.0 mg TOC/l; 3-hr rolling average temp, or vapor recovery system ≤ 550 ppm TOC on 3-hr rolling average.		Meets ECS requirement in 51.1, and exceeds control requirement for new sources.	Meets required control for existing sources and exceeds required controls for new sources.
Part 63, Subpart BBBBBB: Bulk Terminals and Plants and Pipeline Facilities	Area source bulk gasoline terminal (≥ 20,000 gal/ day gasoline throughput), pipeline breakout station, pipeline pumping station, & bulk gasoline plant (< 20,000 gal) as specified.	None	63.11086: Bulk Gasoline Plant Loading Tanks and Trucks	If > 250 gallon, load tank or truck using submerged fill that meets specifications by date installed, and all tanks, minimize gasoline spills and follow other work practices such as monthly leak inspection.	Gasoline Service Stations	Meets 51.1.1 requirement to use submerged fill; although rule has no exemption, exempt facilities are covered by new AQR 102.	Meets presumptive RACT control option 1.
			63.11088 & Table 2: Bulk Gasoline Terminal Loading Rack	If total gasoline throughput ≥ 250,000 gallons/day, equip with vapor collection system and reduce to 80 mg TOC/l.		Meets 51.1 and 51.4.1 requirement for vapor collection and disposal.	Meets 80 mg/L presumptive RACT control requirement.
			63.11088 & Table 2: Bulk Gasoline Terminal Loading Rack	If total gasoline throughput < 250,000 gallons/day use submerge fill with pipe no more than 6 inches from bottom.		Meets 51.1.1 requirement to use submerged fill.	Does not meet presumptive RACT emissions limitation of 80 mg/l, but this level of emissions control would be

Regulation	Affected Source	Construction or Reconstruction Date	40 CFR Citation	Requirement	General Exemptions	AQR Sections 51 & 60.1 Comparison	CTGs Comparison
							required for sources under Subpart XX.
			63.11089: Bulk Gasoline Terminal and Plants	Monthly leak inspection.		Meets 60.1 best practice requirement.	Meets or exceeds presumptive RACT leak detection program.

EPA established or revised these federal emissions standards after determining presumptive RACT for the categories, meaning they represent a progression in control and cost considerations.

Although there are some differences in applicability of the federal rules and the AQRs, DAQ determined that these differences are not such that they decrease the stringency of the SIP if the federal rules are incorporated by reference. For example, Subpart XX regulates facilities with a throughput greater than 20,000 gal/day; AQR Section 51 includes an annual throughput limit that, when divided evenly throughout the year, would result in a lower daily throughput applicability criterion. However, DAQ used the annual throughput limit to provide greater operational flexibility and a source is more likely to exceed the 20,000 gal/day limit in Subpart XX than the annual limit in AQR Section 51, making the applicability of Subpart XX more stringent than that of AQR Section 51.

While Subpart XXa does not include a specific throughput limit equivalent to the presumptive RACT emissions limitation of 80 mg/L, facilities subject to Subpart XXa are likely also subject to Subpart BBBBBB, which includes this specific limit. DAQ determined that EPA's federal rules collectively represent the most current assessment of emissions control capabilities to meet the best available system of emission reduction under Section 111 of the Act and the maximum achievable control technology under Section 112 of the Act. These regulatory standards exceed the statutory requirement for CTG RACT, and are equivalent or more stringent than AQR Section 51. DAQ therefore concluded that adopting these regulations into the SIP will more than satisfy CTG RACT requirements.

DAQ estimates no additional emissions reductions will result from the new CTG RACT requirements, but there will be no loss in emissions reduction from removing AQR Section 51 from the SIP. Replacing AQR Section 51 with the federal rules satisfies the anti-backsliding provisions in Sections 110(l) and 193 of the Act because the federal rules are as or more stringent than AQR Section 51, and adopting them will improve rule effectiveness by consolidating regulatory compliance obligations under the more detailed compliance demonstration requirements of the federal rules. Accordingly, compliance with the federal regulations will not relax the SIP. DAQ asks EPA to replace AQR Section 51 with the federal regulations incorporated by reference into the AQRs.

5.5.3 Replacement of AQR Section 52

Existing SIP-approved regulation AQR Section 52 requires submerged filling and a vapor balance system for all new gas stations after January 1, 1978, and for existing gas stations with an annual output of 96,000 gallons or more after Jan. 1, 1979. The BCC repealed AQR Section 52 in 2011. DAQ adopted the new AQR Section 102 to meet CTG RACT requirements, and as a replacement for the existing SIP-approved regulation. It sets forth design and operating specifications for a vapor recovery system that meets Stage I requirements, and adds specifics on design criteria.

Table 13 displays the requirements of the repealed AQR Section 52 and compares them to the equivalent provisions in AQR Section 102. The table shows that AQR Section 102 is more comprehensive than AQR Section 52.

Table 13. Comparison of New Section 102 with Section 52 Requirements

Repealed Section 52 Requirements		New Section 102 requirements that Meet or Exceed Section 52 Requirements	
Section	**Requirement**	**Section**	**Requirement**
52.1 Storage Tanks	Equip with Permanent submerged fill pipe	102.6 (b)	Equip with Permanent submerged fill pipe
52.2 Loading Operation	Minimize spills	102.5(c)	Minimize releases and spills
52.4 New Gasoline Stations	Equip with vapor control system covering storage tank and truck	102.7(c) 102.8(a)	Install and operate vapor balance system. Connect hoses before filling.
	Prevent release of 90% by weight	102.7(c)(1) 102.7(c)(4)(B) 102.7(c)(4)(G) and (H)	Recover displaced vapors. Meet pressure specifications
	System includes both storage tank and tank truck	102.7 and 102.8	Covers storage tanks and cargo tanks
	Vapor-tight fill connector and return line	102.7.(c)(4)(B) 102.7(c)(4)(F) 102.8(a)(3)	Vapor tight line from tank to truck. Liquid fill and return connections vapor tight caps
	Connected before filling	102.7(c)(1) 102.8(a)(1)	Install and operate vapor balance system. Connect hoses before filling.
	Vapor tight tank truck	102.8(a)(3)	Vapor tight hoses, couplers and adapters
	Refill only tank truck only at facility with vapor control system	102.8(b)	Cargo tank must meet 40 CFR Part 60, Appendix A-8
	Subject to source registration or operating permit requirements	102.4	Permitting and registration requirements
52.4.2.4	Maintain system	102.5(b)	Operate and maintain GDF and controls consistent with good air pollution control practices
52.5 Existing Gasoline Stations	Meet Section 52.4 requirements	102.7(a)	Applies to new and existing sources
52.5.5.3.1 Exemptions	Stations with output less than 96,000 gal/yr exempt	102.2(c)	Stations with throughput less than 120,000 gal/yr on a 12-month rolling basis.
52.6 Registration	Register	102.4	Permitting and registration requirements
52.8 Vehicle Filling	No spilling	n/a	n/a
52.9 Airplane refueling areas	Meet 52.4	102.2(b)	Exempt
N/A	N/A	102.5(c)	Regulates materials sent to waste collection systems Clean-up spills

Repealed Section 52 Requirements		New Section 102 requirements that Meet or Exceed Section 52 Requirements	
Section	Requirement	Section	Requirement
N/A	N/A	102.9	Meet CARB and DAQ testing procedures
N/A	N/A	102.10	Extensive monitoring and inspection requirements
N/A	N/A	102.11	Recordkeeping Requirements

The table notes a slight difference between the two rules in the form of the applicability provisions: AQR Section 52 exempts existing GDFs with an annual output of less than 96,000 gallons from vapor control systems, while AQR Section 102 exempts new and existing GDFs with a throughput of less than 120,000 gallons in any consecutive 12-month period. The two applicability provisions are not directly comparable, since the nonattainment area associated with AQR Section 52 was a significantly smaller geographic area than the one associated with AQR Section 102 (all of HA 212).

Moreover, AQR Section 52 is regulated on an "output" basis and AQR Section 102 on a "throughput" basis. AQR Section 52 requires annual tracking of output, while AQR Section 102 requires monthly tracking of throughput. DAQ views the requirement to examine applicability at least 12 times in a year, as opposed to once, as a strengthening of overall applicability that will improve rule effectiveness. AQR Section 102 will regulate aviation refueling areas; AQR Section 52 did not.

DAQ determined that the vehicle filling requirement in AQR Section 52 resulted in no meaningful emissions reductions because, given the number of consumers and the scale of daily activities at GDFs, controlling consumer behavior at the gas pump is unenforceable. Accordingly, DAQ declined to include the provision in AQR Section 102. The absence of the requirement will not reduce the number of emissions reductions achieved by the SIP, since the rule had 0% effectiveness in practice.

Many aspects of AQR Section 102 are more prescriptive than AQR Section 52. AQR Section 52 required use of a vapor control system to prevent release of at least 90% of VOC in the displaced vapor, but included no specific provisions to validate the performance of the system. AQR Section 102 provides a new static pressure performance standard and a requirement to demonstrate the performance of the system through specific testing procedures.

AQR Section 52 included general obligations to maintain and minimize vapor releases, while AQR Section 102 includes a new work practice requirement section with monitoring requirements to assure compliance; for example, owners or operators have a specific obligation to use nonabsorbent, nonleaking containers rather than just minimize releases. AQR Section 102 regulates material sent to waste collection systems; AQR Section 52 includes no explicit regulation of this material.

The replacement of AQR Section 52 with new AQR Section 102 satisfies the anti-backsliding provisions in Sections 110(l) and 193 of the Act because the new regulation is as or more stringent than AQR Section 52. AQR Section 102 enhances design specifications and testing, monitoring, and recordkeeping requirements compared to AQR Section 52. These requirements increase the stringency of the and improving its effectiveness. Accordingly, AQR Section 102 will not relax the SIP. DAQ asks EPA to replace AQR Section 52 with AQR Section 102 in the SIP.

5.5.4 Replacement of AQR Section 60.1

Existing SIP-approved regulation AQR Section 60.1 establishes a general duty to use good air pollution control practices to minimize equipment leaks. The rule prescribes no specific actions an owner or operator must undertake to meet the general duty standard, but allows the Control Officer broad discretion to prescribe specific measures.

Additionally, AQR Section 60.1 provides no specific criteria for an owner or operator to meet to demonstrate compliance or for the Control Officer to meet in applying the rule. It gives the Control Officer unbounded discretion to mandate any manner of control, which is not consistent with EPA's current practices for approving Control Officer discretion.

The federal rules incorporated by reference into AQR Sections 13.3 and 14.2, along with AQR Sections 101–107, include specific work practice requirements that an owner or operator must follow to reduce fugitive emissions and equipment leaks. These rules are more stringent than AQR Section 60.1 because they prescribe specific actions an owner or operator must take to demonstrate compliance.

Replacing Section 60.1 with the new AQR regulations satisfies the anti-backsliding provisions in Sections 110(l) and 193 of the Act because the new rules are as or more stringent than Section 60.1. They include enhanced work practice standards and testing, monitoring, and recordkeeping requirements compared to AQR Section 60.1. These requirements increase the stringency of the regulation and improve its effectiveness. Accordingly, removing AQR Section 60.1 will not relax the SIP. DAQ asks EPA to replace AQR Section 60.1 with the new AQR regulations.

5.5.5 Replacement of AQR Section 60.2

Existing SIP-approved regulation AQR Section 60.2, which was approved in 1978 and 1981 and repealed in 2011, includes some, but not all, of EPA's recommended presumptive RACT requirements. The requirements in AQR Section 60.2 are not organized or tailored to the specific degreaser type, as recommended by presumptive RACT. AQR Section 105 incorporates all of EPA's CTG presumptive RACT recommendations for both control system A and control system B for each degreaser type, so is more comprehensive than AQR Section 60.2.

Table 14 compares AQR Section 60.2 and AQR Section 105 requirements to show that AQR 105 contains all the requirements of AQR Section 60.2.

Table 14. Comparison of AQR Section 105 with AQR Section 60.2 Requirements

Repealed Section 60.2 Requirements		AQR Section 105 Requirements that Meet or Exceed Section 60.2 Requirements	
Section	**Requirement**	**Section**	**Requirement**
60.2.1.1	Reduce evaporation from waste no greater than 10%	105.5 (c) 105.6(c) 105.7(c)	Reduce evaporation from waste no greater than 20%; cover at all times except during parts entry and removal; minimize solvent carryover using specified control measures; avoid workloads that occupy more than half of the degreaser's open top area; drain above the vapor space, etc.

Repealed Section 60.2 Requirements		AQR Section 105 Requirements that Meet or Exceed Section 60.2 Requirements	
Section	**Requirement**	**Section**	**Requirement**
60.2.1.2	Store waste in covered containers	105.5(c)(2) 105.6(c)(8)	Store waste in nonabsorbent nonleaking containers
60.2.1.3	Equip with cover that can be operator with one hand	105.6(a)(1)	Equip with a cover that the operator can easily open and close without disturbing the vapor zone
60.2.1.3	Drain parts at least 15 sec	105.5(c)(4)	Drain parts at least 15 sec
60.2.4.5	No atomization during spraying	105.5(a) 105.6(a)(3)	Low pressure spray; No atomization or shower-type spray
60.2.1.6	Permanent, conspicuous label of operating requirements	105.8(c)	Permanent and conspicuous post of work practice requirement
60.2.17	Use internal drainage for highly volatile solvent use	105.5(a)(2)	Equip with internal drainage recycling if solvent greater than 32 mm Hg
60.2.1.8	If heated above 120°F, use control system meeting specifications	105.5(b)(1)	If heated above 120°F, use control system meeting specifications

AQR Section 105 includes all the elements of AQR Section 60.2, but is more descriptive of how owners or operators must meet the requirements. For example, AQR Section 60.2 seems to have a more stringent emissions limitation on evaporation losses (no more than 10%), but the actual percentage of evaporative losses is not measurable in practice, making the requirement unenforceable; the rule guarantees no specific level of emissions reduction. AQR Section 105 provides a lower targeted evaporative loss percentage, but a list of work practices accompanies the requirement to minimize solvent loss; for one, the owner or operator must dry parts above the vapor zone (where solvent volatilizes) in a conveyorized degreaser and move parts in and out of the conveyor below a certain speed. Ventilation fans are only allowed in the workspace as needed for workplace safety to reduce evaporative losses in the air caused by over-ventilation. This is just a sample of the work practice requirements in AQR Section 105 to reduce solvent loss.

The comprehensive and prescriptive scope of the ECS and work practice requirements in AQR Section 105 greatly enhance its effectiveness compared to AQR Section 60.2, and DAQ estimates greater emissions reductions in practice from AQR Section 105 than from theoretical reductions achievable under AQR Section 60.2 (even if it were enforceable). Accordingly, DAQ asks EPA to replace AQR Section 60.2 with AQR Section 105.

5.5.6 Replacement of AQR Section 60.3

Existing SIP-approved regulation AQR Section 60.3 regulates application areas, flash-off areas, and large appliance coating lines at surface coating operations. Through the process of identifying potential CTG sources, DAQ determined that no stationary source with large appliance coating lines operates within Clark County or HA 212. Removing Section 60.3.1 from the SIP satisfies the anti-backsliding provisions in Sections 110(l) and 193 of the Act because removing the rule will not reduce the emissions reductions achievable under the SIP. Construction of a new stationary source operating large appliance coating lines would be required to apply current RACT under AQR Sections 12.1 and 12.4.

AQR Sections 101, 103, 104, and 106 regulate the same emission sources, but are more comprehensive in their scope of applicability than AQR Section 60.3. The new regulations establish specific emissions control requirements through the use of add-on emissions controls or low VOC coatings, and include comprehensive work practice requirements to reduce fugitive and leak emissions.

Replacing AQR Section 60.3 with the new regulations satisfies the anti-backsliding provisions in Sections 110(l) and 193 of the Act because the new rules are as or more stringent than Section 60.3. By adopting the new rules, DAQ improves rule effectiveness by adding comprehensive compliance obligations, including monitoring, recordkeeping, and reporting requirements, that are not contained in AQR Section 60.3. Accordingly, removing AQR Section 60.3 will not relax the SIP. DAQ asks EPA to replace AQR Section 60.3 with AQR Sections 101, 103, 104, and 106.

5.5.7 Replacement of AQR Section 60.4

Existing SIP-approved regulation AQR Section 60.4, promulgated in 1979 shortly after EPA issued the CTG and withdrawn by the BCC in 2011, followed EPA's original CTG guidance prohibiting the use of cutback asphalt in the Las Vegas Valley except in limited circumstances. After EPA published the CTG, it issued additional guidance (EPA 1978c, 1979, 1979a) explaining that a complete prohibition on cutback asphalt was impractical. EPA revised its CTG recommendation to either (1) use cutback asphalt with a VOC content ranging from 3–12% (depending on the application), or (2) meet an across-the-board VOC content limit of 5–7%. By EPA's own admission, the applicability of AQR Section 60.4, as approved by the BCC in 1979, is impractical; correspondingly, the rule likely had a lower effectiveness.

AQR Section 107 would replace AQR Section 60.4 in the SIP to restrict the VOC content of cutback asphalt to 0.5% or less by volume throughout Clark County. This is more stringent than EPA's recommended control level, and expands the geographic scope of the rule outside the moderate nonattainment area. AQR Section 107 also brings much-needed clarity to the applicability provisions. AQR Section 60.4 included definitions for slow, medium, and fast cure cutback asphalt, but these definitions are not cited in its applicability provisions, leaving the rule unclear. AQR Section 107 addresses the impracticability concerns raised by EPA and provides a clearer set of requirements for the regulated community, including appropriate monitoring, recordkeeping, and reporting requirements that AQR Section 60.4 lacks. The additional requirements in AQR Section 107 should lead to greater emissions reductions than the theoretical potential of those in AQR Section 60.4.

Accordingly, DAQ finds that AQR Section 107 is at least as stringent as AQR Section 60.4 and removing AQR Section 60.4 from the SIP will make room for a more effective rule with higher emissions reductions. DAQ asks EPA to replace AQR Section 60.4 with AQR Section 107 in the SIP.

6.0 REASONABLY AVAILABLE CONTROL MEASURES

Section 172(c)(1) of the Act requires states to implement RACM to assure a nonattainment area attains the NAAQS as expeditiously as practicable. Specifically, the Act states in 42 U.S.C. 7502(c):

> **(1) IN GENERAL**
> Such plan provisions shall provide for the implementation of all reasonably available control measures as expeditiously as practicable (including such reductions in emissions from existing sources in the area as may be obtained through the adoption, at a minimum, of reasonably available control technology) and shall provide for attainment of the national primary ambient air quality standards.

EPA has not identified a specific set of control measures that qualify as RACM: "Under EPA's policy concerning RACM, there are no measures that are automatically deemed RACM" (70 FR 71612, 71660). Instead, the agency recognizes that the requirement for RACM relates to the requirement to attain the NAAQS: EPA determined that it may approve any SIP submittal lacking specific RACM control measures if the state demonstrates "(a) that reasonable further progress and attainment of the NAAQS are assured, and (b) that application of all RACM would not result in attainment any faster" (44 FR 20372, 20375). EPA's interpretation of the RACM requirement has been litigated and upheld by several courts (e.g., *Sierra Club v. EPA*, 314 F.3d 735 (5th Cir. 2002) and *Sierra Club v. EPA*, 294 F.3d 155 (D.C. Cir. 2002)).

This section briefly explains the control technologies considered for RACM and DAQ's conclusions on whether any control measures qualify as RACM for the moderate attainment plan. Attachment E contains the complete RACM list and analysis (RTP Environmental Associates, Inc. 2024a).

DAQ developed a list of potential control measures using EPA's Menu of Control Measures (EPA 2022b). This menu provides a broad listing of potential measures for reducing NO_x and VOC emissions. DAQ also consulted with the Regional Transportation Commission of Southern Nevada to identify potential transportation control measures that could be applied in the area to reduce mobile source emissions, and considered transportation and nontransportation control measures from other state and local RACM plans (e.g., New Jersey, California, Maryland, New York, Maricopa County).

After a thorough evaluation of available control measures, DAQ found none qualified as RACM under EPA's established criteria. Attainment modeling demonstrates that the ambient ozone air quality level in HA 212 will reach ozone attainment without additional local VOC or NO_x control measures.

Moreover, DAQ cannot implement any potential control measure identified in the RACM analysis in time to advance the attainment date by one year. EPA requires implementation of ozone control measures and modeling of attainment by the last full ozone season preceding the attainment date, which for HA 212 is August 3, 2024. EPA will determine whether HA 212 attained by this date using a three-year average of the annual fourth-highest daily maximum ozone concentrations for 2021–2023. To advance the attainment date by a year (to August 3, 2023), EPA would have to rely on the 3-year average of the annual fourth-highest daily maximum ozone concentrations for the years 2020–2022. DAQ would have had to adopt control measures and put them into effect no later than the end of 2022, which was before EPA reclassified HA 212 to moderate nonattainment status and required a RACM analysis.

In summary, existing federal and local ozone control measures, along with reductions in transported pollution, are projected to bring HA 212 into attainment with the 2015 8-hour ozone NAAQS by August 3, 2024. Therefore, no additional control measures are needed. It is also not feasible to implement additional control measures to advance the attainment date by at least one year because such measures could not have been adopted and put into effect by the end of 2022. Therefore, there are no control measures that satisfy the RACM criteria.

7.0 REASONABLY AVAILABLE CONTROL TECHNOLOGY

EPA's 2015 Ozone NAAQS Implementation Rule requires air pollution control agencies to submit a SIP revision that meets the Act's VOC and NO_x RACT requirements for any nonattainment area classified as "moderate" or higher (40 CFR Part 51.1312(a)). Specifically, Sections 172(c)(1), 182(b), and 182(f) of the Act require that RACT apply to VOC emissions from each source category for which EPA has issued a control technology guideline (CTG) and all major sources of VOC or NO_x. For a moderate nonattainment area such as HA 212, "major stationary source" is defined as a stationary source that emits, or has the potential to emit, at least 100 tpy of either VOC or NO_x (see Section 302 of the Act; Section 182 uses the terms "major stationary source and "major source" interchangeably).

The AQRs require stationary sources to comply with RACT under Sections 12.1.3.6 and 12.4.3. AQR Section 0, "Definitions," defines RACT as:

> the lowest emissions limitation that a particular source is capable of meeting by the application of control technology that is reasonably available, considering technological and economical feasibility...

This requirement applies when a stationary source proposes to construct or modify an emissions unit and the change will cause either (1) a significant increase in the potential to emit of a minor stationary source, or (2) an emissions increase greater than the minor NSR significant level for a pollutant at a major source. For NO_x and VOC emissions increases, the significance levels are 20 tpy (AQR Sections 12.1.1 and 12.4.2.1).

Although the DAQ and EPA definitions for RACT are consistent,[6] the applicability of RACT to stationary sources under the AQRs differs from the required applicability of RACT based on an area's nonattainment classification. Even where the AQRs would regulate the same source and impose the same level of emissions control as federal RACT, EPA requires states to reevaluate previously applied RACT to determine whether it still meets current requirements.

DAQ undertook the required analysis for determining the applicability of CTG RACT (RTP Environmental Associates, Inc. 2024b) and major source RACT (RTP Environmental Associates, Inc. 2023) to stationary sources in HA 212. Appendices C and D include the full analyses; Sections 7.1 and 7.2 summarize the findings.

[6] Neither the Act nor EPA's rules contain a codified definition of RACT for purposes of implementing the Part D RACT requirements in the Act. Instead, EPA has defined RACT in numerous guidance statements as "the lowest emissions limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." EPA first set forth this definition in a memorandum titled "Guidance for Determining Acceptability of SIP Regulations in Non-attainment Areas" (EPA 1976).

7.1 CONTROL TECHNIQUE GUIDELINES FOR REASONABLY AVAILABLE CONTROL TECHNOLOGY

Sections 108 and 183 of the Act direct EPA to issue control technique guidelines (CTGs) that provide air pollution control agencies with information on reducing VOC emissions from certain source categories. The CTGs include information on emissions reduction benefits, installation costs of emissions controls, and environmental impacts associated with using control technologies.

CTGs provide the presumptive norm of VOC control requirements for specific categories of sources (44 FR 53761). EPA recommends that air pollution control agencies adopt regulations consistent with the applicability thresholds and control levels in the CTGs; however, agencies have the freedom to "judge the feasibility of imposing the recommended controls on particular sources, and adjust the controls accordingly" (44 FR 53761).

Section 182(b)(2) of the Act requires that air pollution control agencies implement CTG RACT requirements for each category of VOC stationary sources covered by an EPA-issued CTG when the source operates in a moderate nonattainment area. EPA has not issued CTGs for NO_x emissions from source categories, but has issued Alternative Control Techniques guidance for some NO_x source categories. Unlike CTGs, ACTs do not establish a presumptive level of emissions control; rather, they provide information on potential control measures and costs. They are a resource for determining RACT for individual major sources and for RACM requirements, which are separate under Section 172(c) of the Act.

The CTG RACT analysis in Attachment C describes DAQ's search methodology and identifies potential CTG sources (i.e., sources that might fall into a CTG source category) operating within HA 212. As summarized in the following sections, the analysis establishes presumptive RACT equivalency for some existing SIP-approved regulations, but DAQ will promulgate new rules for some CTG source categories; provides negative declarations for source categories with no CTG sources operating in HA 212; identifies source categories for which new CTG RACT regulations are needed; and calculates potential emissions reductions from new CTG RACT rules.

Table 15 summarizes the anticipated emissions reductions from the new CTG RACT rules.

Table 15. VOC Emissions Reductions Estimates for CTG Source Categories

Source Category	VOC Emissions Reduction (tpd)
Metal and Plastic Parts Surface Coating	0.13
Degreasing	0.33
Industrial Adhesives	0.90
Industrial Cleaning Solvents	3.74
Graphic Arts	2.03
Cutback Asphalt (county wide)	0.66
Total	**7.79**

A total of 7.75 tpd of anticipated emissions reductions are creditable toward ROP, since the reductions will take place within HA 212.

7.1.1 Identification of Source Categories

DAQ used four methods to search for CTG sources operating within HA 212: searching the annual emissions inventory; searching business licenses obtained through the Nevada Secretary of State's website and the Clark County Business License Office; reviewing minor source permits; and searching the internet and yellow pages using key terms. In some cases, DAQ also conducted site inspections to confirm the nature of operations at a given location.

Through these searches, DAQ identified 11 CTG source categories under which stationary sources may be operating within HA 212:

1. Metal and plastic parts surface coating;
2. Metal solvent cleaning (degreasing);
3. Industrial cleaning solvents;
4. Industrial adhesives;
5. Graphic arts;
6. Cutback asphalt;
7. Gasoline service stations;
8. Gasoline loading terminals;
9. Bulk gasoline plants and trucks;
10. Petroleum storage;
11. Surface coating of paper.

7.1.2 CTG Source Categories Rules

CTG sources operating in HA 212 are already regulated to at least the presumptive RACT level under existing SIP-approved regulations, i.e., gasoline loading terminals, bulk gasoline plants and trucks, petroleum storage, and surface coating of paper. The CTG RACT analysis identifies the existing SIP-approved rules that require at least the presumptive RACT level of control for these. DAQ promulgated new rules to replace existing regulations, implementing CTG RACT to improve rule effectiveness by promoting consistency and thoroughness through compliance obligations. DAQ also promulgated new rules for the remaining six source categories:

1. Metal and plastic parts surface coating;
2. Metal solvent cleaning (degreasing);
3. Industrial cleaning solvents;

4. Industrial adhesives;

5. Graphic arts (flexographic, offset lithographic and letterpress printing); and

6. Cutback asphalt.

7.1.2.1 AQR Section 101 for Industrial Adhesive Operations

Adhesives are compounds that allow two surfaces to join. This CTG (EPA 2008) recommends emissions control requirements for adhesive and adhesive primer applications used in a variety of different industrial operations. Presumptive RACT includes several compliance options: EPA recommends that a CTG source use either low-VOC adhesives with good adhesive transfer application methods, or a combination of low-VOC adhesives and add-on controls. Alternatively, EPA allows CTG sources to meet an 85% control efficiency standard.

AQR Section 101 follows EPA's presumptive RACT recommendations, and includes work practices requirements to assure proper handling and disposal of adhesive materials. DAQ estimates that the new rule will result in 0.90 tpd of emissions reductions in HA 212, assuming an 85% emissions reduction and 80% rule effectiveness.

7.1.2.2 AQR Section 102 for Gas Dispensing Facilities

This CTG (EPA 1975) suggests Stage I vapor recovery systems to control VOC emissions when dispensing gasoline from tanker trucks into storage tanks. These systems capture the gas vapors displaced during the filling process and return them into the tank of the delivery truck. The CTG recommends a Stage I vapor recovery system for gasoline stations exceeding 10,000 gallons a month.

Clark County's existing SIP-approved regulation (AQR Section 52) requires submerged filling and a vapor balance system for all stations constructed after Jan. 1, 1978; however, the BCC repealed Section 52 in 2011. DAQ will adopt AQR Section 102 to include the requirements of the existing SIP-approved regulation, and to set forth design and operating specifications for a vapor recovery system that meets Stage I requirements with more clarity and firmer compliance obligations.

Although DAQ believes the new rule will be more effective than Section 52, no additional emission reductions are included in the ROP demonstration relative to this new local control measure.

7.1.2.3 AQR Section 103 for Miscellaneous Metal or Plastic Parts Surface Coating Operations

This CTG (EPA 1978a) applies to miscellaneous metal and plastic parts manufacturers with VOC emissions higher than 3 tpy from use of paints, sealants, caulks, inks, and maskants from coating parts. Presumptive RACT recommends specific limits (in lb VOC/gal) for different coating types. EPA provides additional options for compliance through add-on emissions controls and work practices requirements, estimating that compliance with CTG recommendations would result in a 35% VOC emissions reduction.

DAQ identified several companies whose business operations might be regulated by AQR Section 103; however, the current 2017 base year emissions inventory only includes four point sources. For the attainment plan, DAQ estimated emissions reductions only from those four point sources. DAQ estimates that AQR Section 103 will result in 0.13 tpd of VOC emissions reductions, assuming a 35% emissions reduction from the required emissions controls with 80% rule effectiveness.

7.1.2.4 AQR Section 104 for Industrial Cleaning Solvent Operations

This CTG (EPA 2006a) regulates consumer and commercial products used to remove such compounds as dirt, adhesives, inks, coatings, and other unwanted materials. Industrial operations across all types of source categories may use these products. Presumptive RACT includes work practices requirements, an emissions limitation, and an alternative emissions standard that applies to facilities exceeding a 15 lb/day VOC emissions threshold. EPA estimated that the emissions controls would result in an 85% emissions reduction.

Section 104 adopts EPA's presumptive RACT VOC emissions limitation of 0.42 lb/gal (50 g/L) or at least 85% emissions control efficiency using an ECS, or the alternative composite vapor pressure standard of 8.0 mm Hg measured at 68°F (20°C). The rule also imposes work practices requirements at least equivalent to presumptive RACT.

DAQ estimates that AQR Section 104 will result in 3.74 tpd of VOC emissions reductions, assuming a 94% emissions reduction with an 80% rule effectiveness.

7.1.2.5 AQR Section 105 for Solvent Metal Cleaning Operations

This CTG (EPA 1977a) establishes presumptive RACT to control VOC emissions from cold cleaners, open top vapor degreasers, and conveyorized degreasers that use volatile solvents to clean metal parts.

EPA based presumptive RACT for this source category on equipment specifications and operating requirements, rather than on achieving compliance with a specific emissions limitation. The CTG recommends either of two compliance options—equipment/operation specifications or work practices—for each type of degreaser system; however, states typically adopt both options as RACT.

AQR Section 105 will impose EPA's presumptive RACT equipment specifications, operating requirements, and recommended work practices requirements. Although the new rule establishes requirements for all three types of degreasers, it is likely only cold cleaners operate in HA 212, which would result in lower emissions reductions from the rule. From this assumption, DAQ estimates that AQR Section 105 will result in 0.33 tpd of VOC emissions reductions based on a control efficiency of 53%. Since conservatism was built into this estimate, DAQ did not further discount the reduction with a rule effectiveness adjustment.

7.1.2.6 AQR Section 106 for Offset Lithographic, Letterpress, and Flexible Package Printing and Other Graphic Arts Operations

EPA issued three CTGs (EPA 1978b; EPA 1993a; EPA 2006b; and EPA 2006c) affecting graphic art operations, including flexographic and rotogravure printing, offset and letter press printing, and flexible packaging. The CTGs identify a variety of options for controlling VOC emissions from the inks, coatings, adhesives, and cleaning materials used in such printing operations, including add-on controls (e.g., carbon absorbers, incinerators), waterborne materials, and work practices requirements. The CTGs also recommend VOC material content limits or add-on ECSs to meet presumptive RACT requirements. EPA recommends different ECS control efficiency performance standards, depending on the date of installation.

AQR Section 106 will regulate only flexible packaging and offset and letterpress printing, since DAQ identified no flexographic and rotogravure printing operations in HA 212. The rule follows EPA's presumptive RACT approach for emissions reduction requirements, and includes work practices requirements for handling and disposing of graphic arts material.

DAQ estimates the new rule will result in 2.03 tpd of VOC emissions reductions, assuming an average control efficiency of 66% with 80% rule effectiveness.

7.1.2.7 AQR Section 107 for Cutback Asphalt Operations

Cutback asphalt is used in road construction and other paving operations. This CTG (EPA 1977b) recommends substituting emulsified asphalt for cutback asphalt which EPA estimated would lead to nearly 100% VOC emissions reductions. In subsequent years, however, EPA issued additional guidance (EPA 1978c, 1979a, 1979b) explaining that a complete prohibition on cutback asphalt was impractical and recommended either VOC content limits ranging from 3–12% (depending on the application) or an across-the-board VOC content limit of 5–7%. Subsequently, some states adopted CTG RACT rules with an across-the-board, lower VOC content restriction.

As discussed in Section 5.5.7, AQR Section 107 would replace Section 60.4 in the SIP. The rule will restrict the VOC content of cutback asphalt to 0.5% or less by volume throughout Clark County. DAQ estimates the new rule will result in 0.62 tpd VOC emissions reductions within HA 212 and an additional emissions reduction of 0.04 tpd in the larger Clark County area, assuming 80% rule effectiveness.

7.1.2.8 New Subsections of AQR Sections 13 and 14 for Petroleum Storage

Existing AQR Section 50 requires 40,000-gallon or larger tanks storing petroleum liquid with a vapor pressure of 78 mmHg or greater to equip the tank with a vapor recovery system or floating roof unless the tank is pressured. The rule includes provisions for reducing equipment leaks. Although requirements such as double seals are not included, the rule meets EPA's presumptive RACT recommendation.

DAQ will replace this rule in the SIP by incorporating by reference federal NSPS rules at 40 CFR Part 60, Subparts K, Ka, and Kb, and the federal NESHAP rule at 40 CFR Part 63, Subpart BBBBBB. Section 5.5.1 and Attachment C of this plan explain how the new AQRs are as least as stringent as Section 50 and satisfy CTG RACT requirements.

7.1.2.9 New Subsections of AQR Sections 13 and 14 for Bulk Gas Plants and Terminals

Existing AQR Section 51 regulates some bulk gasoline plants and all bulk gasoline terminals. It requires facilities to use submerged or bottom-filling, vapor collection and disposal, or an equivalent meeting a 90% control efficiency, depending on the facility's annual throughput. This control requirement meets EPA presumptive RACT recommendation.

DAQ will replace AQR Section 51 by incorporating by reference the federal NSPS at 40 CFR Part 60, Subparts XX and XXa, and federal NESHAP at 40 CFR Part 63, Subpart BBBBBB to meet CTG RACT requirements and substitute for the existing AQR Section 51. Section 5.5.2 and Attachment C of this plan explain how the new AQRs are as least as stringent as AQR Section 51 and satisfy CTG RACT requirements.

7.2 MAJOR SOURCE RACT

7.2.1 Introduction

This section explains DAQ's methodology for making major source RACT determinations and summarizes the findings of a series of case-by-case RACT analyses for individual major stationary sources of VOC and NO_x within HA 212. DAQ determined RACT for each major source based on (1) source-provided RACT analyses, and (2) supplemental information and additional analyses conducted by DAQ. The resulting RACT determinations for existing major stationary sources (as defined in 40 CFR Part 70) are based on technically feasible control technologies available in 2023 and their concurrent costs.

Due to the limited number of major sources in HA 212's emissions inventory, DAQ determined that conducting a case-by-case analysis for each existing major stationary source was the most appropriate course for determining RACT. The RACT analyses conducted for each applicable emissions unit for NO_x and/or VOC demonstrated that no additional controls existed that were both technically feasible and cost-effective, so controls (and, in most cases, compliance monitoring) in the sources' current permits was determined to be RACT. Therefore, RACT requirements will result in no emission reductions of either pollutant in HA 212.

7.2.2 Methodology

Attachment D provides a complete RACT analysis for the emission units subject to RACT at each of the major stationary sources involved. DAQ's case-by-case RACT determinations consisted of:

1. Establishing a threshold for each pollutant above which control would not be considered cost-effective. DAQ established a threshold of $5,500/ton for both NO_x and VOC based on a review of other agency thresholds.

2. Identifying all available control options for each type of emission unit subject to RACT (e.g., a 30-MMBtu/hr natural gas-fired boiler).

3. Listing all the control options identified in Step 2.

4. Evaluating each control option and rejecting those not technically feasible for that specific emission unit (e.g., unavailable for that size boiler).

5. Estimating baseline and controlled pollutant emissions (in tpy) and determining the emissions reduction (in tpy) that would occur from application of that control option.

6. Calculating the cost-effectiveness in 2022 dollars per ton of pollutant removed ($/ton) and comparing it to the cost-effectiveness threshold established in Step 1.

7. Determining and evaluating the environmental, energy, and other impacts (i.e., benefits and disbenefits), including whether application of the control technology would increase or decrease emissions of other pollutants, such as GHG or HAP.

8. When a control option for an emission unit was cost-effective and did not result in unacceptable secondary impacts, developing a proposed RACT emissions limitation or averaging approach that also addressed startup and shutdown operations; establishing a schedule for installing and operating the ECS; and preparing testing, monitoring, recordkeeping, and reporting methods that met periodic monitoring or compliance assurance monitoring requirements.

DAQ first provided major stationary sources an opportunity to conduct their own RACT analyses to submit to DAQ for review. To assure uniformity in cost estimates, DAQ advised sources to use a 6% interest rate and to presume the emission unit had a remaining useful life of 30 years; however, sources could submit information justifying a different useful life and/or actual interest rates, which DAQ would consider in final RACT determinations.

DAQ identified two approaches for determining baseline emissions for cost-effectiveness calculations. The first used the emission unit's PTE, including consideration of existing, enforceable control technologies. The second used either the source's or an emission unit's actual emissions. DAQ allowed a major source to compute cost-effectiveness using the second approach when its actual emissions over a representative period of operations were less than 70% of PTE: that is, the source could use actual emissions as a baseline for all its emission units if the source's actual emissions were 70% below its PTE, or the source could use actual emissions for an individual emission unit if that unit's actual emissions were 70% below its PTE.

DAQ advised sources to submit RACT analysis information on each emission unit with a PTE equal to or greater than 5 tpy. In a few cases, DAQ asked a source to evaluate RACT for a group of similar emission units (e.g., storage tanks, emergency backup generators) even when the individual units fell below the 5-tpy threshold. This approach assured that each RACT analysis addressed major contributions to each source's PTE.

All the draft RACT analyses submitted generally followed DAQ guidance, providing information on emission units, available control technologies, and cost-effectiveness. Attachment D contains the information from these analyses, along with DAQ's further analyses and conclusions.

After receiving self-analyses from the major sources, DAQ reviewed the information for thoroughness, reliability, and to determine if the source:

1. Included all emission units;

2. Searched the RACT/BACT/LAER Clearinghouse and literature for potential control technologies;

3. Listed all available control technologies;

4. Followed the guidelines for determining RACT; and

5. Documented critical parts of the analysis (e.g., how sources determined the remaining useful life of equipment).

These self-analyses proved useful to DAQ's final RACT determinations. In determining the suitability of a given control option for RACT, DAQ was guided by the cost-effectiveness values it had approved in past control technology determinations, the cost-effectiveness guidance provided by EPA, and the cost thresholds other states found acceptable. DAQ used a cost-effectiveness threshold of $5,500/ton, which was among the highest in a survey of state agencies (San Diego Air Pollution Control District 2020).

For its cost-effectiveness analyses, DAQ used a 30-year equipment life term and 6% interest rate to make conservative estimates, i.e., it selected values that would result in a lower cost-effectiveness (in $/ton removed) than a less conservative estimate for items like maintenance costs. DAQ also considered the remaining life for either (1) the control device, if it could continue to operate when the emission unit it serves is replaced by a new one, or (2) the emission unit, if the control technique was inherent to the unit. An example of the first instance is an selective catalytic reduction (SCR) system that treats the exhaust gas from a diesel generator: if the generator is replaced, the SCR system can be connected to the new generator and continue operating. An example of the second is modifying a generator for Injection Timing Retard: that technology would be part of the existing unit, so the remaining life of the generator would be used.

DAQ assumed a 30-year remaining useful life unless a source documented a shorter time. If a source provided cost estimates using a shorter useful life but did not provide adequate documentation to justify, DAQ revised the analysis using a 30-year life expectancy. If a source provided adequate documentation for a shorter life, DAQ reviewed the information and decided whether to revise its analysis.

Developing cost-effectiveness values was an iterative process. Initial analyses were first-order approximations based on information in the literature except where vendor information on cost or applicability was available. After conducting the first-order approximation, costs were not corrected for inflation unless the first calculation for a unit fell below the cost-effectiveness threshold; in such cases, DAQ adjusted the cost for inflation and recalculated cost-effectiveness. If the inflation-adjusted cost-effectiveness value was still below the threshold of $5,500/ton, DAQ reviewed the parameters to determine whether further refinements to the cost estimate were warranted; if so, revised parameters were developed and cost-effectiveness recalculated. A cost-effectiveness value that was still below the threshold indicated the control technology for that emission unit was reasonable.

Most of the cost-effectiveness developed in these analyses relied on values from available literature for at least some of the parameters used in the calculations. Major sources could elect to develop parameters based on vendor quotes for application of a specific control technology on specific emission units and request that DAQ use those parameters instead. Since vendor quotes for specific units are generally more accurate and up-to-date than literature values, DAQ usually accepted the recalculated cost-effectiveness value.

After determining what control measures qualified as RACT, DAQ determined RACT emissions limitations. If DAQ determined the existing level of control was RACT, it accepted the emissions limitations imposed through the source's permit, which provided an effective emissions limit (or equivalent) and adequate monitoring, reporting, and recordkeeping conditions to ensure compliance. DAQ did not consider existing limits based on annual mass emissions appropriate for RACT. If the existing level of control was RACT and the affected source only had an annual mass emission limit, DAQ applied a concentration-based limit (i.e., Y ppm @ X% O_2) derived from the facility's base-line emissions estimate for that unit.

The RACT emissions limitations derived from this process represent the lowest achievable emissions level with which existing emission unit(s) can continuously comply using the proposed RACT control option. RACT also includes requirements for startup, shutdown, and malfunction (SSM) periods; these provisions may be included in a single RACT emissions limitation, or they may be regulated under a separate emissions limitation when including emissions in a generally applicable emissions limitation would cause the proposed limitation to be too lax during normal operations. DAQ also considered using work practice requirements when numerical emissions limitations were not feasible.

7.2.3 Major VOC and NO_x Sources in HA 212

Through a review of the 2017 NEI and major source (40 CFR Part 70) operating permits, DAQ identified the following major sources that could be subject to major source VOC or NO_x RACT requirements.

Table 16. Major Sources in the HA 212 Nonattainment Area

Facility ID	Facility Name	Total Facility NO_x PTE (tpy)	2017 NEI Emissions (tpy)	2017 NEI Emissions (tpd)
NO_x Major Sources				
114	NAFB	199.0[1]	19.81	0.05
257	Caesars Consolidated Properties	370.1	19.9	0.05
16304	Switch, Ltd.	246.18	33.23	0.09
825	MGM Resorts International	757.05	65.07	0.18
7	Clark Generating Station	2465.9	115.40	0.32
423	Sun Peak Generating Station	249.4	15.89	0.04
393	Saguaro Power Company	164.1	102.79	0.28
VOC Major Sources				
13	Calnev Pipe Line LLC	187.4	59.31	0.16
7	Clark Generating Station	216.5	14.12	0.04

[1] NAFB's most recent ATC permit (10/13/22) states that NO_x PTE is now 200.47 tpy.

DAQ asked each major source to prepare and submit RACT analyses for any emission units with a PTE of 5 tpy or more of either NO_x or VOC. All agreed to provide the information. Because actual emissions from nearly all sources were much lower than PTE, the sources generally used actual emissions baselines per DAQ guidance.

7.2.4 RACT Analysis Summary

RACT analyses were conducted for emission units at the eight major stationary sources in HA 212. This section summarizes the results.

By emission unit type, there were 199 generators (all but 1 emergency generators); 9 natural gas-fired boilers, including 2 auxiliary boilers at a power plant; 16 simple cycle turbines; 6 combined cycle turbines; 2 aircraft engine test cells (hush houses); and 1 petroleum storage terminal with VOC emissions from storage tanks, a vapor recovery system, loading racks, remediation equipment (for treating contaminated soil), and fugitive emissions from numerous points within the system (e.g., valves, flanges, etc.). NO_x RACT was conducted for all emission units except the Calnev Pipe Line terminal, which had only VOC RACT emission units. Five turbines at Clark Generating Station were evaluated for both VOC RACT and NO_x RACT.

For all emission units evaluated, DAQ determined RACT was the current level of control. Most of the sources had existing permitted limitations or practices that represented RACT; for those that did not, DAQ set emissions limitations based on existing control equipment. With few exceptions, the existing monitoring, reporting, and recordkeeping provisions in the permits ensure compliance with RACT-level limits; the DAQ analysis identified new or revised monitoring, reporting, and recordkeeping provisions as needed to ensure compliance, including during SSM.

The principal reason the RACT analyses resulted in determinations that no additional control was cost-effective is that most emission units are already well-controlled because of former best available control technology (BACT) and existing RACT requirements in the AQR Section 12 series. The reduction in emissions from installing more stringent controls, by either adding to or replacing the existing controls, would be small, and a small reduction in emissions usually results in a high cost-effectiveness value.

For example, the seven natural gas-fired boilers at Caesars and MGM Resorts International (MGMRI) are already restricted to around 30 ppm, a relatively low emissions rate. Current technologies are available to reduce emissions to as low as 9 ppm, but this level of control would not achieve much additional emissions reduction: Caesars' CP01 boiler emissions rate limit, currently about 35 ppm at 3% O_2, could be reduced to as low as 10 ppm, but the reduction in actual emissions would be only 1.08 tpy. When looking at the cost to upgrade emissions controls, such relatively small reductions are not generally cost-effective.

7.2.5 Actual Emissions Methodology: Results and Considerations

The presumption behind the actual-emissions methodology is that the annual actual emissions used for a cost-effectiveness calculation represent normal operations for the source or individual emission unit. Because actual emissions from many individual emission units were quite low, the cost-effectiveness calculation was particularly sensitive to actual emissions levels.[7]

DAQ's RACT analyses used a variety of approaches to derive actual emissions. The sources' most common approach was to use the highest two-year average (in tpy) during a five-year (2017–2021) or three-year (2019–2021) period. One source used the highest annual emissions during 2019–2021; another used the highest-emitting generator in 2017; yet another used a three-year (2019–2021) average. Calnev estimated the actual VOC emissions from most of its equipment based on the type of equipment and seals. DAQ determined that all the different approaches yielded actual emissions that ranged from representative of normal operations (long-term averages) to conservative (e.g., highest annual emissions over a period of years); therefore, DAQ accepted the estimates.

7.2.6 RACT Summaries for Individual Major Stationary Sources

7.2.6.1 Nellis Air Force Base

The emission units at NAFB consist of nine diesel generators (eight emergency ones) and a hush house with two aircraft engine test cells. The generator analyses considered 18 control technologies, but only SCR was considered for the hush house. The Part 70 operating permit (DES 2021b) for the generators already requires good combustion practices (GCP) and good maintenance practices (GMP); turbocharging; Injection Timing Retard for emissions units A032, G032, and G033; and aftercoolers for all but the nonemergency generator (A032). No other technologies were found cost-effective.

For the hush house, only SCR was considered an available control technology. Information on SCR costs, feasibility, and even level of control was unavailable, but given the nature of the unit (intermittent testing of aircraft engines) and the fact that SCR is not suited for intermittent operations, DAQ concluded that SCR would be neither technically feasible for intermittent operations nor cost-effective. Therefore, RACT for these units consists of the existing control technologies; emissions limits; monitoring, reporting, and recordkeeping; and SSM provisions already contained in the NAFB Part 70 operating permit.

7.2.6.2 Caesars

Caesars owns several properties with boilers and emergency generators (DES 2021c). DAQ identified and evaluated 23 boiler control technologies. For five boilers, only one control technology (in addition to those already required) appeared cost-effective: switching to ceramic fiber burners. This control would have reduced emissions from 30 ppm to 15 at 3% O_2, saved fuel, and reduced

[7] For example, assume a boiler with actual emissions of 2.74 tpy and a reduction of 1.15 tpy from a control technology has a cost effectiveness of $7,533/ton, above the $5,500/ton threshold. If the actual emissions rose only 2.26 tpy, to 5 tpy, the reduction would be 2.1 tpy and the cost-effectiveness would drop to $4,128/ton, below the threshold, making the boiler cost-effective for RACT.

maintenance. However, all Caesars' boilers are about 30 MMBtu/hr in size and, according to several manufacturers, ceramic fiber burner applications are available only up to about 16 MMBtu/hr.[8]

Further research indicates that metal mesh burners, like ceramic burners, are ultra-low NO_x burners and can reduce emissions substantially—in this case, down to 9–15 ppm. The burners are suitable for larger boilers, up to 100 MMBtu/hr or more, but their cost is much higher (an estimated $250,000, since metal mesh burners are custom-designed and built for each boiler make and model) and there are no fuel savings. DAQ concluded that metal mesh burner technology is not cost-effective for these boilers.

In summary, DAQ finds that ceramic fiber burners are not available for these emission units and metal mesh burners are not cost-effective, so concluded that existing controls constitute RACT for these boilers.

Caesars' properties also host 27 emergency diesel generators subject to RACT review that are rated from 600–2,100 kW. These are limited to 100 hours of operation per year for testing and maintenance, and up to 50 hours per year for nonemergency situations (which count toward the 100 hours). All the engines are turbocharged and aftercooled. Of the 18 control technologies evaluated, DAQ determined that only the existing controls (i.e., turbocharging, GCP/GMP, and aftercooler) were cost-effective, and concluded they constitute RACT for the emergency diesel generators. The Caesars Part 70 operating permit (Source ID 257) includes compliance and monitoring requirements to ensure these existing controls conditions are met; DAQ concluded these constitute adequate monitoring, reporting, and recordkeeping to ensure RACT compliance.

7.2.6.3 Switch, Ltd.

Switch, Ltd. operates no emissions units with a PTE above 5 tpy NO_x, but DAQ asked the company to review its 117 large (3,353-hp/2,503-kW) emergency diesel generators in a RACT analysis.

The Switch Part 70 operating permit (DES 2021d) requires turbochargers and aftercoolers on all emergency generators. It requires Switch to follow the manufacturer's operations and maintenance guidance, and to ensure all 117 units comply with the emissions limitations in 40 CFR Part 60, Subpart IIII. DAQ concluded that these requirements are RACT because the NSPS for engines represent state-of-the-art emissions controls for these types of units. Switch's operating permit includes compliance and monitoring requirements to ensure these conditions are met; DAQ concluded these constitute adequate monitoring, reporting, and recordkeeping to ensure RACT compliance.

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[8] From 2019 to 2021, the five boilers' highest annual emissions were 10.89 tpy NO_x; had ceramic burners been applicable, they would have reduced that to 5.445 tpy, reducing NO_x by the same amount. The burners have the benefit of increasing efficiency and saving fuel, which makes them more cost-effective; for example, the cost-effectiveness for unit CP02, with 2.74 tpy actual emissions (without considering fuel savings), is $3,895/ton, which is cost-effective; but the cost-effectiveness for unit CP04, with 1.08 tpy actual emissions, is $9,881/ton, which is not. However, assuming the lowest hours of operation (446.6 for CP01 in 2021) and 5% fuel savings, would be $6,815/year, resulting in a cost-effectiveness of -$1,080 to -$2,739/year (depending on the unit), which is cost-effective. The reduction in actual emissions from equipping the boilers with ceramic burners (had they been available) would have been 5.445 tpy NO_x.

7.2.6.4 MGM Resorts International

MGMRI is currently a major source of NO_x with a source-wide PTE of 757.05 tpy, but it reported only 65.07 tpy of actual NO_x emissions in 2017. Emission units include two natural gas-fired boilers, each with a capacity of 32.66 MMBtu/hr, and 46 diesel-fired emergency generators ranging from 1,100–3,700 hp.

DAQ evaluated 23 boiler control technologies; only ceramic fiber burners appeared to be potentially feasible as additional RACT. However, the MGMRI boilers all are about 30 MMBtu/hr in size and, as discussed in Section 7.2.6.2, ceramic fiber and metal mesh burner applications are available only up to about 16 MMBtu/hr and are not cost-effective.

All 46 of MGMRI's emergency diesel generators are required to follow the manufacturer's operations and maintenance guidance, which is generally accepted as constituting GCP. In addition, the operating permit requires all units to have turbochargers and aftercoolers except:

- Turbochargers only: EX007–EX010 and NY27–NY29.
- Neither: TM01.

TM01 is the only unit for which the operating permit does not explicitly require turbocharging or aftercoolers, but it is also the only unit specifically mentioned as subject to EPA Tier Certification. The unit's manufactured control technology must comply with the applicable NSPS, thereby meeting the requirements of this certification and satisfying the definition of RACT.

The emergency generators currently:

- Are all required to practice GCP and GMP;
- Have and use turbochargers and aftercoolers, except the eight units that are not required to have aftercoolers (EX007–010 & NY 27–29, and TM01); and
- Have one EPA Tier-Certified unit (TM01). It must meet the appropriate limit in 40 CFR Part 60, Subpart IIII.

DAQ determined that the current control techniques (GCP/GMP, turbochargers, and aftercoolers, except as noted above) constitute RACT for all the units reviewed. In addition to GCP/GMP, RACT for TM01 includes meeting the Tier Certification requirements, specifically the emissions limits. MGMRI's Part 70 operating permit (Source ID 825) includes compliance and monitoring requirements to ensure all the above conditions are met; DAQ concluded these conditions constitute adequate monitoring, reporting, and recordkeeping to ensure RACT compliance.

7.2.6.5 Calnev Pipe Line

Calnev Pipe Line, LLC (Calnev), a Kinder Morgan subsidiary, owns and operates the Las Vegas Terminal (LVT), a petroleum products distribution terminal facility in HA 212. Operations include receiving petroleum fuel products via pipeline or truck and transferring gasoline, diesel, and biodiesel from storage tanks into trucks via loading racks.

LVT had a VOC PTE of 187.4 tpy and actual VOC emissions of 59.31 tpy in 2017. Most individual emissions units have a VOC PTE below 5 tpy, but DAQ asked LVT to include a majority of the emissions units in its RACT analysis.

LVT grouped individual emission units so the group PTE exceeded 5 tpy, then conducted RACT analyses on the following groups:

1. Storage tanks (total PTE of 61.3 tpy VOC) (Attachment D, Table 3-1);[9]

2. A vapor recovery unit (14.5 tpy VOC);[10]

3. Loading racks (65.7 tpy VOC);[11]

4. A remediation system (37.7 tpy VOC);[12] and

5. Fugitive components, such as valves, flanges, fittings, and pump seals (6.6 tpy VOC).

DAQ conducted a RACT analysis for each of these units/groups and determined they are well-controlled and no additional control technologies are cost-effective, so the existing controls and compliance measures (specified in the Part 70 operating permit (Source ID 13)) constitute RACT. DAQ also reviewed the monitoring, reporting, and recordkeeping requirements in the operating permit and determined they are effective in ensuring compliance with RACT.

7.2.6.6 Clark Generating Station

The Clark Generating Station (CGS) plant has a PTE of 2,465.9 tpy and had actual emissions of 115.4 tpy in 2017. Emissions units analyzed at CGS consisted of 13 simple cycle combustion turbines (Unit 4 and Units 11–22) and four combined cycle turbine units (Units 5–8). All turbines are already subject to RACT for NO_x; Units 4 and 5–8 are already subject to RACT for VOC (DES 2020a).

For this NO_x RACT evaluation, DAQ considered the use of SCR, water injection, and GCP for Unit 4. For Units 5–8, DAQ considered the installation of SCR with the existing dry-low NO_x combustors (DLNC); for Units 11–12, DAQ considered the installation of DLNC with the current use of SCR and water injection. For the VOC RACT evaluation, DAQ considered the use of oxidation catalyst controls and GCP for Units 4–8; Units 11–22 are already equipped with oxidation catalyst controls. All other control technologies are technically infeasible.

DAQ found no cost-effective NO_x or VOC control options for any unit except Unit 4. The proposed NO_x RACT for Unit 4 was an emissions limit of 120 ppm(dry volume) @ 15% O_2, based on the use of GCP for all periods of operation. For all other units, DAQ determined the current NO_x limits

[9] No tank has a PTE of 5 tpy or more.
[10] The vapor recovery unit is itself a control device that LVT says is considered BACT.
[11] There are 15 loading racks. Most of the 65.7 tpy PTE is from gasoline dispensing. Assuming each rack has the same PTE, 65.7÷15 = 4.38 tpy per rack, less than the 5-tpy PTE threshold for RACT review.
[12] This system is also considered BACT per LVT.

represented RACT based on the use of existing control equipment and compliance determination procedures (Part 70 operating permit (Source ID 7)).

DAQ determined that VOC RACT for Unit 4 is an emissions limitation of 21.6 lb/hr based on GCP. For Units 5–8, DAQ determined the existing VOC limits represent RACT based on existing control configuration and compliance determination procedures.

DAQ defined NO_x and VOC RACT for startup and shutdown operations at CGS as GCP, and included a requirement to develop a best operating practices guideline with adequate reporting and recordkeeping procedures to ensure each unit maintains compliance with the "good operating practices" work practice standard.

7.2.6.7 Sun Peak Generating Station

The Sun Peak Generating Station (SPGS) plant has a NO_x PTE of 249 tpy and had actual emissions of 15.89 tpy in 2017. The emission units analyzed at SPGS consist of three natural gas-fired, simple cycle combustion turbines (Units 3–5). All units were subject to a RACT evaluation for NO_x; VOC RACT did not apply because emissions were below the RACT applicability threshold of 5 tpy PTE (DES 2020b). No other sources at the facility have NO_x or VOC emissions above the applicability threshold.

All turbines are currently equipped with water injection for NO_x control (Part 70 operating permit (Source ID 423)). Potential control options include SCR, DLNC, and a combination of SCR with DLNC for all units. All other options are technically infeasible. The cost evaluation identified no cost-effective control options; therefore, DAQ determined the current controls represent RACT. DAQ will require the source to continue to meet its NO_x emissions limitations and follow existing compliance determination procedures to satisfy RACT.

DAQ concluded that GCP would also apply to startup and shutdown operations at SPGS, and included a requirement to develop a best operating practices guideline with adequate reporting and recordkeeping procedures to ensure that each emission unit maintains compliance with the "good operating practice" work practice standard.

7.2.6.8 Saguaro Power Company

Saguaro Power Company (SPC) had the highest emissions relative to PTE of all the major sources reviewed: a PTE of 164.1 tpy NO_x and actual emissions of 102.79 tpy NO_x in 2017. The emissions units consist of two natural gas-fired combined cycle turbine units (Units 1 and 2) and two natural gas-fired auxiliary boilers (Units 5 and 6). All turbines and boilers were subject to a NO_x RACT evaluation; VOC emissions are below the RACT applicability threshold (DES 2020c).

All turbines are currently equipped with steam injection and SCR for NO_x control (Part 70 operating permit (Source ID 393)). Potentially available control technologies include DLNC and SCR catalyst replacement; all other options are technically infeasible. The cost evaluation was based on actual emissions data, and showed there were no cost-effective control options for either unit. DAQ determined that existing controls represent RACT, and will require continued compliance with current NO_x limits and compliance determination procedures.

Both boilers are equipped with low NO_x burners (LNBs), although the Unit 5 boiler is also equipped with flue gas recirculation. DAQ evaluated an extensive list of potential NO_x control technologies for Unit 5 and, with a few exceptions, found all were technically infeasible. DAQ lacked sufficient information to determine feasibility for certain combustion-related technologies, including LNBs, staged combustion, excess air reduction, and gas flow modifiers; however, none of these options would be considered cost-effective even if deemed technically feasible. Therefore, DAQ concluded the existing controls represent RACT and will require continued compliance with the current NO_x limit and compliance determination procedures.

DAQ also evaluated an extensive list of potential control technologies for Unit 6, and concluded that only the following technologies are technically feasible: LNB upgrade with flue gas recirculation, installation of a ceramic fiber burner, installation of a forced internal recirculation burner, and fuel-induced recirculation. Based on the cost evaluation, DAQ concluded there are no cost-effective upgrades for this unit. Therefore, the existing controls represent RACT and DAQ will require continued compliance with the current NO_x limit and compliance determination methods.

Finally, DAQ proposed the use of GCP as RACT for all units during startup and shutdown operations, with an additional requirement to develop a best operating practices guideline.

8.0 RATE OF PROGRESS

Section 182(b)(1)(A) of the Act requires states to provide at least a 15% VOC emissions reduction in moderate ozone nonattainment areas within six years from a 1990 emissions baseline year. In the 2015 Ozone Implementation Rule, EPA interpreted this 15% ROP requirement to apply to the 2015 ozone NAAQS based on the corresponding baseline year (2017). EPA indicated the ROP requirement applies in any moderate ozone nonattainment area where it was not previously met for an earlier ozone NAAQS (40 CFR 51.1310(a)(4)).

Since EPA classified HA 212 as a "marginal" ozone nonattainment area for the 1997 ozone NAAQS, an ROP requirement for ozone has never applied to HA 212. However, DAQ must meet this requirement for the 2015 ozone NAAQS.

For the ROP analysis, DAQ developed an inventory different from the 2015 ozone NAAQS SIP Inventory (Ramboll US Consulting, Inc. 2024b, Attachment F). DAQ based this "ROP inventory" on EPA's most recent 2016v3 EMP, and it includes 2017 base year and 2026 future year inventories. Attachment G provides detailed information on DAQ's ROP analysis (Ramboll US Consulting, Inc. 2024c).

As described in this section, HA 212's 2017 VOC base year ROP inventory equals 109.81 tpd. DAQ must reduce HA 212's VOC emissions by at least 16.47 tpd to meet the 15% ROP. This reduction must come from within the boundaries of HA 212, and DAQ may not substitute NO_x emission reductions or take credit for control measures implemented outside HA 212.

With implementation of all current control measures, DAQ projects 2026 VOC emissions to decrease by 5.09 tpd to 104.72 tpd. These reductions are principally related to anticipated emissions reductions in the on-road mobile sector. The 2026 VOC emissions inventory does not include reductions from any new local control measures. To meet ROP, DAQ must impose new control requirements that achieve at least 11.38 tpd VOC emissions reductions.

Table 17. Summary of HA 212 Summer Weekday VOC Emissions (tpd)

Source Category	2017 VOC Base Year Emissions (tpd)	2026 VOC[1] Estimated Emissions (tpd)
Point source	1.25	1.35
Nonpoint source	57.72	61.69
On-road mobile	24.81	14.60
Nonroad mobile	24.03	24.25
Airports (commercial & federal)	1.96	2.75
Locomotives	0.04	0.03
ERC	Federal	0.05
Total, tpd	109.81	104.72

[1] Emissions estimated without additional control measures proposed in this attainment plan.

DAQ plans to meet the additional VOC emissions reduction requirement through (1) implementation of CTG RACT on stationary sources, and (2) adoption of a local control measure to restrict

VOC content in AIM coatings. The following table shows the expected emissions reductions from each new control measure.

Table 18. Projected VOC Emissions Reductions from New Control Measures

Control Measure	Description	2026 VOC Emissions Reductions (tpd)
Existing Control Measures	Already adopted	5.09
CTG Reasonable Available Control Technology	Metal and plastic parts surface coating	0.13
	Degreasing	0.33
	Industrial adhesives	0.90
	Industrial cleaning solvents	3.74
	Graphic arts	2.03
	Cutback asphalt (HA 212)	0.62
	Subtotal	*7.75*
Local Control Measures	AIM coatings from OTC model rules (Phases I–II)	3.83
	Subtotal	*3.83*
	Total Reduction	**16.67**

The new control measures, combined with existing ones, will reduce future year VOC emissions by 16.67 tpd to a total of 88.05 tpd. This represents a 15.18% decrease from the 2017 base year inventory, which satisfies ROP. Appendices C and G provide complete explanations and documentation of these calculations.

Although the 2015 ozone implementation rule requires VOC emissions reductions to occur within the six years following the 2017 base year (i.e., by 2023), the timing presented a challenge because the requirement to achieve ROP did not become effective in HA 212 until January 5, 2023. Given the time necessary to develop an emissions inventory, conduct attainment demonstration modeling, identify sources subject to CTG and major source RACT, develop regulations to implement additional control measures, and allow for EPA SIP approval, the required VOC emissions reductions could not be achieved by the attainment date.

"EPA has routinely concluded in these circumstances that the area should demonstrate the required ROP as expeditiously as practicable once the statutory date for achieving such ROP had passed" (68 FR 55472; also 65 FR 31485, 63 FR 28898, and 62 FR 31343). Although no court has directly addressed the "as expeditious as practicable" standard, courts have addressed other issues concerning ROP plans submitted after the statutory date that demonstrated ROP as expeditiously as practicable without expressing any concern. For instance, 68 FR 55472 cited *Sierra Club v. EPA*, 252 F.3d 943 (8th Cir. 2001), where the court upheld the calculation methods used in an ROP plan that was submitted three years after the statutory date and demonstrated ROP achievement seven years after the statutory date. DAQ intends to implement the required ROP as expeditiously as practicable; it adopted the CTG RACT rules in early 2024, and expects full implementation by September 2025.

For this ROP demonstration, DAQ estimated future year emissions using the 2026 projected emissions inventory because emissions reductions will occur close in time to that inventory year.

9.0 PERMIT PROGRAM FOR NEW AND MODIFIED MAJOR SOURCES

Section 172(c)(5) of the Act requires the state to implement a permit program consistent with the requirements of Section 173. DAQ has a long-standing and fully implemented Nonattainment New Source Review (NNSR) permitting program for major sources under AQR Section 12.3. DAQ certifies that the existing NNSR program is as least as stringent as the requirements at 40 CFR Part 51.165 for ozone and its precursors, and includes everything needed to meet EPA's minimum requirements for moderate nonattainment areas for the 2015 ozone NAAQS.

9.1 EXISTING NNSR RULES

AQR Section 12.3 contains Clark County's existing NNSR regulations. These rules were last revised on July 20, 2021 (NDEP 2021), and EPA approved the revisions on May 6, 2024, finding the rules met the marginal area NNSR requirements for the 2015 ozone NAAQS (89 FR 37137).

9.2 HOW CLARK COUNTY REGULATIONS MEET MINIMUM NNSR SIP REQUIREMENTS

Table 19 shows how DAQ's regulations meet EPA's minimum requirements for an approvable NNSR SIP for a moderate nonattainment area for the 2015 ozone NAAQS. Accordingly, DAQ certifies that its existing NNSR program is as least as stringent as the requirements at 40 CFR Part 51.165 for ozone and its precursors.

Table 19. Compliance Demonstration for Clark County's NNSR Program

40 CFR Part 51.165 Requirement		Compliance Demonstration AQR Section 12.3 and Section 12.7.5
1.	(a)(1)(iv)(A)(*1*)(i)-(iv) and (*2*): Major source thresholds for ozone – VOC and NOx	Section 12.3.2 (y)(1)(C) definition of "major stationary source" includes the 100 tpy threshold for moderate ozone nonattainment area (and other thresholds up to the extreme classification).
2.	(a)(1)(iv)(A)(*3*): Change constitutes a major source by itself	Section 12.3.2(y)(2) definition of "major stationary source" mirrors EPA's rule: "if the change would constitute a major stationary source by itself"
3.	(a)(1)(v)(E): Significant net emissions increase of NOx is significant for ozone	Section 12.3.2(ii)(3)(A) definition of "regulated NSR pollutant"; Section 12.3.2(aa) definition of "net emissions increase"; Section 12.3.2(mm) definition of "significant" Rules define NO_x as an ozone precursor pollutant and set a 40 tpy significant threshold.
4.	(a)(1)(v)(F): Any emissions change of VOC in Extreme area triggers NNSR	Not applicable because no Clark County nonattainment area is or previously has been classified as Extreme.
5.	(a)(1)(x)(A)-(C) and (E): Significant emissions rates for VOC and NO_x as ozone precursors	Section 12.3.2(mm)(4) definition of "significant" sets 40 tpy significant emissions rate for NO_x and VOC.
6.	(a)(2) Applicability Procedures	Section 12.3.1 Applicability Procedures applies NNSR to the same project emissions increases as the federal program.
7.	(a)(3)(ii)(C)(*1*)-(*2*): Provisions for emissions reduction credits	Section 12.3.6.6(a) Emission Reduction Requirements, Section 12.7.5(i) Stationary source shutdowns mirrors EPA's requirements.

40 CFR Part 51.165 Requirement		**Compliance Demonstration AQR Section 12.3 and Section 12.7.5**
8.	(a)(*8*): Requirements for VOC apply to NOx as ozone precursors	Section 12.3.2 (y)(1)(C) definition of "major stationary source"; Section 12.3.2(ii)(3)(A) definition of "regulated NSR pollutant"; Section 12.3.2(mm)(4) definition of "significant"; Section 12.3.6.5 Quantity Table 12.3-1 Offset Ratios: regulates NOx as a regulated NSR pollutant; sets the significant rate at the same level as VOC and requires the same offset ratio as VOC.
9.	(a)(*9*)(ii)-(iv): Offset ratios for VOC and NOx for ozone nonattainment areas	Section 12.3.6.5 Quantity Table 12.3-1 Offset Ratios establishes offset ratio for moderate ozone nonattainment area at 1.15:1.
10.	(a)(11) – interprecursor trading (partially vacated)	Section 12.3.6.3(b) has been removed from the rules consistent with the *Sierra Club* (2021).
11.	(a)(12) Anti-backsliding provision(s), where applicable	No other areas in Clark County are designated nonattainment for a previous ozone NAAQS.
12.	(f) Actual PALs	Section 12.3.9 (PAL) essentially mirrors EPA's PAL provisions.
13.	(i) Public Participation Requirements	Section 12.3.8 Public Participation requires publication in both a newspaper and on the DAQ website.

9.3 CONCLUSION

DAQ certifies that the 2021 version of its SIP-approved NNSR program in AQR Sections 12.3 and 12.7.5 meet EPA's minimum SIP requirements for the 2015 8-hour ozone NAAQS NNSR program for the Las Vegas Valley moderate nonattainment area.

10.0 INSPECTION AND MAINTENANCE PLAN

Section 182(b)(4) of the Act requires moderate ozone nonattainment areas to provide for a vehicle inspection and maintenance (I/M) program that meets pre-1990 performance standards, or a "Basic I/M" program. A vehicle I/M program conducts periodic inspections of the emissions control systems on motor vehicles. These programs help reduce VOC and NO_x emissions by identifying cars and trucks with high emissions that may need emissions-related repairs.

40 CFR Part 51, Subpart S sets forth requirements for I/M programs. The rule requires that:

> If a marginal ozone nonattainment area, not required to implement enhanced I/M under paragraph (a)(1) of this section, is reclassified to moderate, a basic I/M program shall be implemented in the 1990 Census-defined urbanized area(s) with a population of 200,000 or more... (40 CFR 51.350(a)(8))

EPA's basic I/M program requirements are based on the original I/M program operating in New Jersey in the early 1970s, and require testing only of light-duty passenger cars using a simple idle test. EPA originally estimated its basic I/M performance standard achieved about a 5% reduction in highway mobile source VOC emissions (57 FR 52950). However, since EPA originally promulgated I/M regulations, light-duty trucks have become a significant part of the motor vehicle fleet and are now included in nearly all I/M programs; also, more sophisticated steady-state tests have been developed and are being used in I/M programs to improve emissions reduction performance. Modern I/M programs almost always achieve greater emissions reductions than basic I/M requires.

The Clark County Vehicle Inspection and Maintenance Program is detailed in the *Carbon Monoxide State Implementation Plan: Las Vegas Valley Nonattainment Area, Clark County, Nevada* (CO SIP), approved by the Board of County Commissioners in August 2000 and by EPA in September 2004 (69 FR 56351). EPA classified the program as an "EPA low enhanced I/M program" meeting the requirements of 40 CFR Part 51.351(g), which means the program approved in the CO SIP also exceeds the requirements for moderate ozone nonattainment areas in 40 CFR Part 51.352.

The county I/M program is governed under Chapters 445B.700-835 of the Nevada Revised Statutes and Chapter 445B of the Nevada Administrative Code, and administered by the Nevada DMV. These regulations establish annual testing procedures for 1968 or newer gasoline-powered vehicles, regardless of size, and for diesel-powered vehicles with a manufacturer's GVWR of up to 14,000 lb. Onboard diagnostic II testing procedures are used for 1996 and newer vehicles, while older vehicles are tested with a two-speed idle test. Any used-car dealer in Nevada must provide a valid passing emissions test with any vehicle they sell that will be registered in Clark County.

The I/M program includes waiver provisions for motorists who spend $450 on emission-related repairs. To qualify, a 2G Licensed Authorized Station must repair the vehicle, and the waiver application must include receipts from the station showing that the owner spent at least $450 on parts other than a catalytic converter, a fuel inlet restrictor or air injection system, or on labor other than emissions testing. For low-income consumers, the Smog Free Clark County Voucher Program will pay for up to $975 in emissions-related repairs for 1968–1999 model year vehicles. Eligibility had been based on income, but program revisions implemented in August 2024 eliminated this requirement. Clark County administers this program through an independent contractor.

The I/M program allows emissions testing exemptions for new vehicles in their first three years of registration, and for new hybrid-electric vehicles in their first five years of registration. A waiver for classic cars was revised by the state legislature in 2021, so cars with "Classic Vehicle," "Classic Rod," or "Old Timer" license plates must now carry classic or antique vehicle insurance with limited-use restrictions that include a limit of 5,000 miles driven per year. Vehicles unqualified to carry any of these special license plates must meet emissions inspection requirements. No waivers are available for any vehicle that emits visible smoke.

EPA's low enhanced performance standard meets the Act's requirement that it be based on centralized, annual testing of light-duty cars and trucks, but provides flexibility that allows comprehensive, decentralized programs. As approved and implemented, the I/M program is a decentralized program that satisfies the applicable performance standard, with test-only and test-and-repair vehicle inspection stations.

According to 40 CFR Part 51.353(a), test-only stations have the presumption of equivalency to a centralized test-only network and receive the same emission reduction credits as a centralized system. 40 CFR Part 51.353 also allows the test-and-repair component to receive the same credits if it can be demonstrated that type of facility achieves the same level of effectiveness as a test-only station. In 2002, DAQ conducted a study to compare the effectiveness of test-only stations and test-and-repair stations to establish the overall effectiveness of the I/M program (Parsons 2002, Attachment H). The study showed that test-and-repair stations and test-only stations were equally effective in reducing emissions, making the I/M effectiveness rate for the Clark County program 100%.

The county's I/M program requires licensed inspectors to meet training requirements and follow certification procedures (40 CFR Part 51.367). Specifically, certified inspectors must have verified training that includes a course approved by the Nevada DMV and Department of Public Safety, written and practical testing, and fulfillment of a separate certification process. In general terms, inspector training covers the purpose and goals of enhanced I/M, emission control devices, configuration and inspection, test procedures, and rationale.

The I/M program also requires class 2 inspector training and licensing that conforms to the requirements in 40 CFR Part 51.369. Certification and licensing is required to perform work on or service vehicle emissions components. Chapters 445B.485–445B.5084 of the Nevada Administrative Code contain additional information about these requirements, as does the "State of Nevada State Implementation Plan for an Enhanced Program for the Inspection and Maintenance of Motor Vehicles for Las Vegas Valley and Boulder City, Nevada" (69 FR 56531; CO SIP, Appendix E).

The Nevada DMV is the agency responsible for implementing and monitoring the state's I/M program, including inspector training and certification programs. As specified in NRS Chapters 445B.765 and 445B.810, the DMV submits annual reports on the I/M program to EPA in July to comply with the provisions of 40 CFR Part 51.366.

The moderate ozone classification requires implementation of a Basic I/M program. States with existing I/M programs must conduct and submit a SIP and Performance Standard Modeling (PSM) analysis, and document any necessary program revisions, as part of their SIP submission to ensure their I/M program is operating at or above the Basic I/M performance standard level.

I/M performance standards are defined at 40 CFR Part 51.352 (for Basic I/M programs) and 40 CFR Part 51.351 (for Enhanced I/M programs). A PSM analysis shows whether the state I/M program (or modifications thereto) meets the applicable performance standard, which establishes the level of emission reductions that a mandatory I/M program must meet or exceed. States that determine through a PSM analysis that an existing SIP-approved program would meet the performance standard for the 2015 ozone NAAQS without modification can submit a written statement certifying the existing program as adequate to meet the 2015 ozone NAAQS SIP requirements.

To perform a PSM analysis, two scenarios had to be modeled:

1. An existing state program scenario, representing Clark County's I/M program as it operates today (including a delay in initial testing for the newest six model-year vehicles) and factoring in all local parameters and control measures, as well as inputs required to define the existing program; and

2. EPA's performance standard benchmark scenario, representing the applicable EPA defined benchmark program, including all local area parameters and control measures, and the EPA's I/M program, with the elements of the applicable performance standard.

The PSM analysis compares the results of these scenarios to determine whether the existing program's emissions rates are the same as, or lower than, EPA's performance standard. If the existing program shows the same or lower emissions levels for VOC and NO_x as EPA's performance standard benchmark program—to within 0.02 grams per mile (g/mile)—then it meets the enhanced performance standard.

DAQ performed modeling for its PSM analysis using the MOVES3.1 emissions model with the latest planning assumptions (e.g., local fleet age distribution, vehicle miles traveled, meteorology, fuel parameters, etc.). These assumptions were based on 2020 data that are updated every three years in conjunction with the federal requirements for statewide NEI development.

DAQ performed three modeling scenarios: a no-I/M case, the basic I/M performance standard, and the low enhanced I/M performance standard. All used the most recently required mobile source emission factor model, along with other locally variable parameters, e.g., age distribution of the local in-use fleet, average ambient temperature, distribution of vehicle miles traveled, average speed, etc. DAQ compared the proposed program and performance standard scenarios to the no-I/M case to determine the reduction produced by the I/M programs.

Table 20 shows the result: DAQ's existing I/M program meets the basic performance standard because emissions reductions are higher than in the base case. Therefore, DAQ certifies that its current I/M program meets the applicable basic I/M performance requirements of 40 CFR Part 51.352.

Table 20. I/M Performance Standard Modeling for HA 212's Existing I/M Program

Pollutant	2023 Clark Co. Base Case (tpd)	2023 Basic I/M Performance Standard (tpd)	Meets Basic I/M Performance Standard
VOC	17.01	17.66	Yes
NOx	19.15	19.85	Yes

Tables 21 and 22 list the modeling inputs used.

Table 21. MOVES3.1 I/M Input for Clark County Low Enhanced I/M Program

Pol Proc ID	St ID	Co ID	Yr ID	Src Type ID	Fuel Type ID	IM Prog ID	Inspect Freq	Test Stds ID	Beg Model Yr ID	End Model Yr ID	Use IM? Y/N	Comp. Factor
101	32	32003	2023	21	1	2	1	12	1968	1995	Y	60.90
101	32	32003	2023	21	1	10	1	51	1996	2020	Y	89.19
101	32	32003	2023	21	5	202	1	12	1968	1995	Y	60.90
101	32	32003	2023	21	5	210	1	51	1996	2020	Y	89.19
101	32	32003	2023	31	1	2	1	12	1968	1995	Y	60.90
101	32	32003	2023	31	1	10	1	51	1996	2020	Y	89.19
101	32	32003	2023	31	5	202	1	12	1968	1995	Y	60.90
101	32	32003	2023	31	5	210	1	51	1996	2020	Y	89.19
101	32	32003	2023	32	1	2	1	12	1968	1995	Y	60.90
101	32	32003	2023	32	1	10	1	51	1996	2020	Y	89.19
101	32	32003	2023	32	5	202	1	12	1968	1995	Y	60.90
101	32	32003	2023	32	5	210	1	51	1996	2020	Y	89.19
101	32	32003	2023	42	1	2	1	12	1968	2020	Y	90.32
101	32	32003	2023	43	1	2	1	12	1968	2020	Y	90.32
101	32	32003	2023	51	1	2	1	12	1968	2020	Y	90.32
101	32	32003	2023	52	1	2	1	12	1968	2020	Y	90.32
101	32	32003	2023	53	1	2	1	12	1968	2020	Y	90.32
101	32	32003	2023	54	1	2	1	12	1968	2020	Y	90.32
101	32	32003	2023	61	1	2	1	12	1968	2020	Y	90.32
102	32	32003	2023	21	1	2	1	12	1968	1995	Y	60.90
102	32	32003	2023	21	1	10	1	51	1996	2020	Y	89.19
102	32	32003	2023	21	5	202	1	12	1968	1995	Y	60.90
102	32	32003	2023	21	5	210	1	51	1996	2020	Y	89.19
102	32	32003	2023	31	1	2	1	12	1968	1995	Y	60.90
102	32	32003	2023	31	1	10	1	51	1996	2020	Y	89.19
102	32	32003	2023	31	5	202	1	12	1968	1995	Y	60.90
102	32	32003	2023	31	5	210	1	51	1996	2020	Y	89.19
102	32	32003	2023	32	1	2	1	12	1968	1995	Y	60.90
102	32	32003	2023	32	1	10	1	51	1996	2020	Y	89.19
102	32	32003	2023	32	5	202	1	12	1968	1995	Y	60.90
102	32	32003	2023	32	5	210	1	51	1996	2020	Y	89.19
102	32	32003	2023	42	1	2	1	12	1968	2020	Y	90.32
102	32	32003	2023	43	1	2	1	12	1968	2020	Y	90.32
102	32	32003	2023	51	1	2	1	12	1968	2020	Y	90.32
102	32	32003	2023	52	1	2	1	12	1968	2020	Y	90.32
102	32	32003	2023	53	1	2	1	12	1968	2020	Y	90.32
102	32	32003	2023	54	1	2	1	12	1968	2020	Y	90.32
102	32	32003	2023	61	1	2	1	12	1968	2020	Y	90.32
112	32	32003	2023	21	1	8	1	43	1996	2020	Y	89.19
112	32	32003	2023	21	5	208	1	43	1996	2020	Y	89.19
112	32	32003	2023	31	1	8	1	43	1996	2020	Y	89.19
112	32	32003	2023	31	5	208	1	43	1996	2020	Y	89.19
112	32	32003	2023	32	1	8	1	43	1996	2020	Y	89.19

Pol Proc ID	St ID	Co ID	Yr ID	Src Type ID	Fuel Type ID	IM Prog ID	Inspect Freq	Test Stds ID	Beg Model Yr ID	End Model Yr ID	Use IM? Y/N	Comp. Factor
112	32	32003	2023	32	5	208	1	43	1996	2020	Y	89.19
113	32	32003	2023	21	1	8	1	43	1996	2020	Y	89.19
113	32	32003	2023	21	5	208	1	43	1996	2020	Y	89.19
113	32	32003	2023	31	1	8	1	43	1996	2020	Y	89.19
113	32	32003	2023	31	5	208	1	43	1996	2020	Y	89.19
113	32	32003	2023	32	1	8	1	43	1996	2020	Y	89.19
113	32	32003	2023	32	5	208	1	43	1996	2020	Y	89.19
201	32	32003	2023	21	1	2	1	12	1968	1995	Y	60.90
201	32	32003	2023	21	1	10	1	51	1996	2020	Y	89.19
201	32	32003	2023	21	5	202	1	12	1968	1995	Y	60.90
201	32	32003	2023	21	5	210	1	51	1996	2020	Y	89.19
201	32	32003	2023	31	1	2	1	12	1968	1995	Y	60.90
201	32	32003	2023	31	1	10	1	51	1996	2020	Y	89.19
201	32	32003	2023	31	5	202	1	12	1968	1995	Y	60.90
201	32	32003	2023	31	5	210	1	51	1996	2020	Y	89.19
201	32	32003	2023	32	1	2	1	12	1968	1995	Y	60.90
201	32	32003	2023	32	1	10	1	51	1996	2020	Y	89.19
201	32	32003	2023	32	5	202	1	12	1968	1995	Y	60.90
201	32	32003	2023	32	5	210	1	51	1996	2020	Y	89.19
201	32	32003	2023	42	1	2	1	12	1968	2020	Y	90.32
201	32	32003	2023	43	1	2	1	12	1968	2020	Y	90.32
201	32	32003	2023	51	1	2	1	12	1968	2020	Y	90.32
201	32	32003	2023	52	1	2	1	12	1968	2020	Y	90.32
201	32	32003	2023	53	1	2	1	12	1968	2020	Y	90.32
201	32	32003	2023	54	1	2	1	12	1968	2020	Y	90.32
201	32	32003	2023	61	1	2	1	12	1968	2020	Y	90.32
202	32	32003	2023	21	1	2	1	12	1968	1995	Y	60.90
202	32	32003	2023	21	1	10	1	51	1996	2020	Y	89.19
202	32	32003	2023	21	5	202	1	12	1968	1995	Y	60.90
202	32	32003	2023	21	5	210	1	51	1996	2020	Y	89.19
202	32	32003	2023	31	1	2	1	12	1968	1995	Y	60.90
202	32	32003	2023	31	1	10	1	51	1996	2020	Y	89.19
202	32	32003	2023	31	5	202	1	12	1968	1995	Y	60.90
202	32	32003	2023	31	5	210	1	51	1996	2020	Y	89.19
202	32	32003	2023	32	1	2	1	12	1968	1995	Y	60.90
202	32	32003	2023	32	1	10	1	51	1996	2020	Y	89.19
202	32	32003	2023	32	5	202	1	12	1968	1995	Y	60.90
202	32	32003	2023	32	5	210	1	51	1996	2020	Y	89.19
202	32	32003	2023	42	1	2	1	12	1968	2020	Y	90.32
202	32	32003	2023	43	1	2	1	12	1968	2020	Y	90.32
202	32	32003	2023	51	1	2	1	12	1968	2020	Y	90.32
202	32	32003	2023	52	1	2	1	12	1968	2020	Y	90.32
202	32	32003	2023	53	1	2	1	12	1968	2020	Y	90.32
202	32	32003	2023	54	1	2	1	12	1968	2020	Y	90.32
202	32	32003	2023	61	1	2	1	12	1968	2020	Y	90.32
301	32	32003	2023	21	1	10	1	51	1996	2020	Y	89.19

Pol Proc ID	St ID	Co ID	Yr ID	Src Type ID	Fuel Type ID	IM Prog ID	Inspect Freq	Test Stds ID	Beg Model Yr ID	End Model Yr ID	Use IM? Y/N	Comp. Factor
301	32	32003	2023	21	5	210	1	51	1996	2020	Y	89.19
301	32	32003	2023	31	1	10	1	51	1996	2020	Y	89.19
301	32	32003	2023	31	5	210	1	51	1996	2020	Y	89.19
301	32	32003	2023	32	1	10	1	51	1996	2020	Y	89.19
301	32	32003	2023	32	5	210	1	51	1996	2020	Y	89.19
302	32	32003	2023	21	1	10	1	51	1996	2020	Y	89.19
302	32	32003	2023	21	5	210	1	51	1996	2020	Y	89.19
302	32	32003	2023	31	1	10	1	51	1996	2020	Y	89.19
302	32	32003	2023	31	5	210	1	51	1996	2020	Y	89.19
302	32	32003	2023	32	1	10	1	51	1996	2020	Y	89.19
302	32	32003	2023	32	5	210	1	51	1996	2020	Y	89.19

Table 22. MOVES3.1 I/M Input for the Basic Performance Standard

Pol Proc ID	St ID	Co ID	Yr ID	Src Type ID	Fuel Type ID	IM Prog ID	Inspect Freq	Test Stds ID	Beg Model Yr ID	End Model Yr ID	Use IM? Y/N	Comp. Factor
101	32	32003	2023	21	1	111	1	11	1968	2000	Y	100
102	32	32003	2023	21	1	111	1	11	1968	2000	Y	100
301	32	32003	2023	21	1	111	1	11	1968	2000	Y	100
302	32	32003	2023	21	1	111	1	11	1968	2000	Y	100
101	32	32003	2023	21	1	151	1	51	2001	2022	Y	100
102	32	32003	2023	21	1	151	1	51	2001	2022	Y	100
301	32	32003	2023	21	1	151	1	51	2001	2022	Y	100
302	32	32003	2023	21	1	151	1	51	2001	2022	Y	100
112	32	32003	2023	21	1	143	1	43	2001	2022	Y	100
101	32	32003	2023	21	5	111	1	11	1968	2000	Y	100
102	32	32003	2023	21	5	111	1	11	1968	2000	Y	100
301	32	32003	2023	21	5	111	1	11	1968	2000	Y	100
302	32	32003	2023	21	5	111	1	11	1968	2000	Y	100
101	32	32003	2023	21	5	151	1	51	2001	2022	Y	100
102	32	32003	2023	21	5	151	1	51	2001	2022	Y	100
301	32	32003	2023	21	5	151	1	51	2001	2022	Y	100
302	32	32003	2023	21	5	151	1	51	2001	2022	Y	100
112	32	32003	2023	21	5	143	1	43	2001	2022	Y	100

11.0 CONTINGENCY MEASURES

11.1 POLICY BACKGROUND

Section 172(c)(9) of the Act provides that a moderate ozone nonattainment area SIP must include contingency measures that will apply if the area fails either to achieve attainment by the attainment date or to meet RFP requirements (42 U.S.C. 7502). The SIP shall provide specific measures to be implemented if the area fails to make RFP or to attain the NAAQS by the attainment date; these contingency measures will take effect without further action by the state or the EPA Administrator if the area fails to reach attainment or RFP.

The Act provides no definition for the term "contingency measures," nor has EPA defined the term in a rule. But the preamble to EPA's 2015 Ozone NAAQS Implementation Rule states:

> [c]ontingency measures required under CAA sections 172(c)(9) and 182(c)(9) must be fully adopted rules or measures that can take effect without further action by the state or EPA upon failure to meet milestones or attain by the attainment deadline. Per EPA guidance, these measures should provide 1 year's worth of emissions reductions, or approximately 3 percent of the baseline emissions inventory. (83 FR 62998 at 63026, December 6, 2018)

The purpose of contingency measures is to assure continued air quality improvement during the SIP development period, before an air pollution control agency must submit a revised SIP implementing additional control measures for a higher nonattainment classification. EPA's guidance states that, although the Act requires no specific quantity of emissions reductions to satisfy contingency measures, reductions equivalent to one year's worth (OYW) of RFP—i.e., up to 3% of the VOC emissions base year inventory—would be adequate (57 FR 13498 at 13511, April 16, 1992).

An agency could achieve this entirely with VOC emission reductions, or could substitute with NO_x emissions reductions. "The EPA interprets RFP under CAA section 172(c)(2) to be an average 3 percent per year emissions reduction of either VOC or NO_X" (40 CFR Part 51.1300(l)). For areas like HA 212, where an air pollution control agency is submitting an ROP plan with the SIP revision, the agency may substitute NO_x emissions reductions for only up to 90% of the required VOC emissions reductions (EPA 1993b).

An agency may propose emissions reductions from outside the nonattainment area if a technical demonstration shows that will help the area reach attainment, or EPA may approve contingency measure plans that provide for less than 3% of VOC emissions reductions, if appropriate.

In March 2023, EPA released a draft guidance document suggesting a revised formula for determining the amount and type of emissions reductions needed to meet contingency measure requirements (EPA 2023a). In it, EPA explains that recent court decisions found prior contingency measure policies inconsistent with the Act because the guidance allowed credit for already-implemented emissions reduction measures. The draft guidance suggests a new policy, that contingency measures be control measures that are:

- Not required to meet other attainment plan obligations;

- Require minimum further action to take effect; and
- Provide conditional and prospective emissions reductions.

EPA also provided a new draft formula for determining the quantity of emissions reductions that agencies should require from contingency measures. EPA has not finalized this draft guidance, and the existing guidance that bases contingency measures on OYW of RFP remains in effect (1993c).

11.2 METHODOLOGY

Some air pollution control agencies have begun to rely on EPA's draft guidance for computing contingency measure emissions reductions. DAQ, however, finds that the draft guidance may not be well-suited for computing the number of emissions reductions required for HA 212 because it does not adapt its formula for OYW of Progress for an area like HA 212 that is:

1. Modeling attainment by the attainment date without need for additional emissions reductions;

2. Continuing to achieve new emissions reductions from ROP and CTG RACT after the area's attainment date; and

3. Showing that VOC emissions reductions are more effective in reducing ozone ambient air concentrations in the near term.

Since EPA has not finalized this draft guidance, DAQ's contingency measure demonstration follows EPA's existing guidance (1993c). As explained above, the required amount of VOC emissions reductions is up to 3% of the 2017 VOC base year emissions inventory. Table 23 shows the quantity of emissions reductions based on 3% of the 2017 VOC base year emissions inventory.

Table 23. Contingency Measure Calculation using Methodology in Current EPA Guidance

Guidance Version	CM Approach	Inventory Used	VOC	NO_x	Total Emissions Reduction: VOC (tpd)	Total Emissions Reduction: NO_x (tpd)	Total (tpd)
Current (1993c)	OYW of RFP (up to 3% VOC)	2017 base year[1]	107.73	95.07	Up to 3.23	None; NOx substitution permissible up to 90%	Up to 3.23

[1] Based on verified 2017 NEI..

Notwithstanding DAQ's use of the existing guidance to compute the quantity of emissions reductions required for contingency measures, DAQ will follow EPA's draft guidance to the extent that it requires prospective control measures with minimum further action to take effect, since this aspect of the draft guidance has some support in case law.

11.3 NO_X OR VOC CONTROL MEASURES

OYW of RFP contingency measures are generally based on achieving VOC emissions reductions. EPA allows areas that have already submitted an approvable ROP plan to substitute NO_x emissions reductions for the required VOC emissions reductions (EPA 1993b). DAQ will submit an approvable ROP plan for HA 212 with its contingency measure plan, allowing it to use either pollutant to satisfy OYW of RFP. DAQ evaluated the potential effectiveness of control measures aimed at reducing either pollutant.

The attainment modeling shows HA 212 includes a balanced mix of NO_x and VOC sensitive ozone production on the top 10 simulated days at the monitoring site with the highest modeled design value, Joe Neal (Ramboll US Consulting, Inc. 2024a, Attachment B, pp. 186 and 196). There are substantial variations in day-to-day sensitivities, meaning that, in the near term, ambient air concentrations of ozone should respond to either VOC or NO_x emissions reductions, making reductions in either pollutant a candidate for effective contingency measures (Ramboll US Consulting, Inc. 2024a).

To confirm this observation, DAQ conducted two future year sensitivity modeling scenarios, using CAMx modeling (Ramboll US Consulting, Inc. 2024a, Attachment B, Appendix B). These scenarios used the ROP modeling case and further reduced all NO_x, then VOC, anthropogenic source category emissions by an across-the-board 10% in all categories except airports.

The CAMx model yielded estimated ozone design value changes at six monitoring sites in HA 212 for each sensitivity scenario (NO_x, VOC). With respect to NO_x sensitivity, three monitoring sites showed a slight increase in design value while all monitoring sites show a positive sensitivity to VOC emissions reductions. DAQ concluded the modeling supports designing a contingency measure that relies only on VOC emissions reductions because VOC emissions reductions are up to 12.5 times as effective in reducing ambient ozone concentrations, in the near term, than NO_x emissions reductions.

11.4 TOTAL VOC EMISSIONS REDUCTIONS QUANTITY

In EPA's draft guidance, EPA notes that EPA's existing OYW of RFP method (i.e., using up to 3% of the VOC emissions inventory) may overcalculate the emissions reductions needed to meet contingency measure requirements, and provides the OYW of Progress method as a means of tailoring the required amount of emissions reductions to a lower number, as appropriate (EPA 2023a). Importantly, a contingency measure is not required to bring an area into attainment, and should not result in emissions reductions beyond those needed to attain. "[T]he goal for contingency measures is not a new attainment demonstration, but rather just continued progress" (EPA 2023b). Given that attainment modeling and source contribution analysis showed that no additional local measures are necessary for HA 212 to achieve attainment, DAQ believes that 3% of the 2017 VOC base year emissions inventory more than adequately fulfills the requirement for contingency measures.

The attainment modeling, discussed in Section 4.0, shows that HA 212 can reach attainment with no changes in emissions between the base year and attainment year inventories because transport is the predominant contributor to increased ambient ozone concentrations in the area, and DAQ expects recently enacted transportation control measures in California to reduce transport emissions such that HA 212 will achieve attainment without any need for added local control measures.

Even if HA 212 failed to achieve attainment by the required date, the unavoidable delay in achieving full implementation of ROP and RACT emissions control requirements would provide emissions reductions after the attainment date greater than those required by contingency measures. HA 212 would continue to make substantial progress toward attainment during the subsequent planning period regardless of contingency measures emissions reductions. Nonetheless, DAQ evaluated measures that could provide up to 3% of the 2017 VOC base year emissions inventory as potential contingency measures.

11.5 PROPOSED CONTROL MEASURE

DAQ identified CARB's Phase I EVR executive orders and certification requirements as a viable control measure to satisfy the contingency measure requirement. These Executive Orders, posted on the CARB website (https://ww2.arb.ca.gov/resources/documents/vapor-recovery-phase-i-evr-executive-orders), include:

- VR-101: Phil-Tite Phase I Vapor Recovery System
- VR-102: OPW Phase I Vapor Recovery System
- VR-104: CNI Manufacturing Phase I Vapor Recovery System
- VR-105: EMCO Wheaton Retail Phase I Vapor Recovery System.

EVR performance standards and specifications improve in-use performance of vapor recovery systems, lowering emissions. Specifically, CARB's Phase I EVR requirements control gas vapors during the transfer of gasoline from a cargo tank to a GDF tank. Under EVR specifications, stationary sources must replace pre-EVR Phase I equipment with CARB-compliant components. Additional information on CARB's vapor recovery requirements, including a link to certification and test procedures, is available at https://ww2.arb.ca.gov/our-work/programs/vapor-recovery/resources and detailed below.

Stage I Enhanced Vapor Recovery System

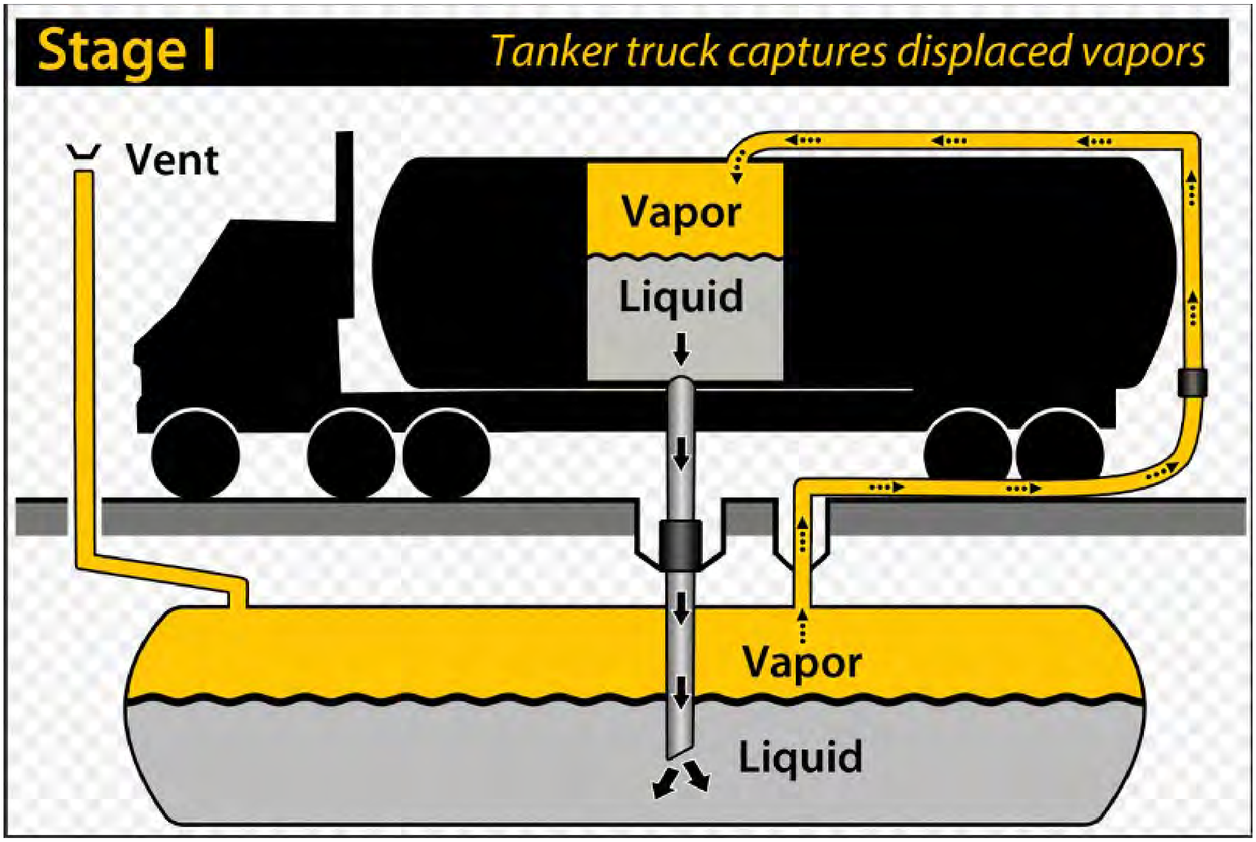
Stage I (or Phase I) refers to the emissions source category associated with the transfer of gasoline from tanker trucks to underground storage tanks (USTs). As a UST is filled, gasoline vapors are displaced to the atmosphere or routed back to the tanker truck.

In 1975, EPA established Stage I vapor recovery to control emissions at GDFs when gasoline is transferred from tanker trucks to USTs. GDFs are federally required to use Stage I vapor recovery when their maximum gasoline throughput is equal to or greater than 100,000 gallons per month (1.2 million gallons per year) (40 CFR Part 63, Subpart CCCCCC).

During tank filling, submerged pipes are also used to minimize the formation of VOC and hazardous air pollutant (HAP) emissions that result from the displacement of gasoline vapors in the UST. Most gasoline station tanks in HA 212 are equipped with these Stage I controls.

To achieve emissions reductions beyond EPA's Stage I controls, some agencies began requiring use of an approved vapor balancing system to recover the displaced gasoline vapors routed back to tanker trucks. In 2000, CARB adopted its own Phase I EVR regulations, which require a 98% recovery efficiency (CARB 2020; NJDEP 2023). Prior to CARB's 2000 regulation, recovery systems were generally rated to operate at 90–95% efficiency.

Figure 10 depicts a GDF vapor recovery system.



Source: Shelby County public domain website (Shelby County Health Department 2024).

Figure 10. Vapor Recovery System at a GDF.

As a contingency measure, GDFs in HA 212 will meet CARB Phase I EVR requirements with CARB-certified systems that achieve a recovery efficiency of 98% for USTs and 95% for above-ground tanks. DAQ included the 95% requirement for above-ground tanks in its rule, but anticipates that only the 98% emissions reduction requirement will apply in practice, since tanks operating in Clark County are primarily USTs.

11.6 ACHIEVABLE EMISSIONS REDUCTIONS

The contingency measure will require additional emissions reductions compared to conventional submerged filling and vapor recovery at GDFs. Attachment F (ROP emissions inventory) reports estimated emissions for SCC codes 2501060051 and 2501060053.

The 2026 emissions inventory for these SCC codes was derived from the 2016v3 EMP. EPA based estimates in the 2016v3 EMP on an interpolation of emissions between 2002 NEI data and 2017 NEI data, assuming no change to underlying emissions factors and 90% control using EPA Stage I requirements (EPA 2022c, 2023c). DAQ forecast 2026 Stage I emissions from the 2016 base year emissions reported in the modeling platform, assuming no change in these assumptions.

Adopting new EVR equipment specifications will result in a 98% control efficiency in transfer losses, since Clark County's regulated tank population is predominantly comprised of USTs. If the contingency measure is triggered, DAQ estimates the contingency measure rule will be fully effective by 2026 and reduce future emissions for these SCC source categories by an additional 80%, or 3.72 tpd of VOC compared to current emission controls. Table 24 displays emissions reduction estimates for each SCC category (see Attachment J for details).

Table 24. Estimated VOC Emissions Reductions (tpd) within HA 212 from Enhanced Vapor Recovery Rule

Source Description	SCC Source Category	2026 Projected Emissions (tpd)	Current Emissions Control Level (%)	New Emissions Control Level (%)	Estimated VOC Emissions Reductions (tpd)	Total Reduction (%)
Stage1: Submerged Filling	2501060051	4.474	90%	98%	3.58	80%
Stage1: Balanced Submerged Filling	2501060053	0.173	90%	98%	0.14	80%
	Total	**4.65**	**—**	**—**	**3.72**	**80%**
	Amount Needed for Contingency Measure (tpd)			**3.23**		
	Excess Emissions Reductions (tpd)			**0.49**		

The calculated emissions reduction exceeds the 3.23 tpd of VOC emissions reduction needed to meet the contingency measure requirement. Accordingly, the CARB EVR rule will fully satisfy contingency measure requirements.

11.7 COST EFFECTIVENESS OF CONTROL MEASURE

Fixed costs of complying with CARB's Phase I EVR systems in Massachusetts were estimated as an average of $7,500, with lower costs for GDFs already equipped with some CARB-compliant components. Table 25 shows the estimated annual cost per ton of VOC reduced by GDF throughput (ERG 2012).

Table 25. 2012 Phase I EVR Cost Effectiveness Estimates[1]

Gasoline Throughput (gallons/year)	Cost-Effectiveness ($/ton VOC)
<120,000	$55,005
120,000 to 240,000	$17,029
240,001 to 500,000	$7,327
500,001 to 1,000,000	$2,992
1,000,001 to 2,000,000	$885
>2,000,000	-$253

[1] Source: MDEP 2012 (modified Table 4-11).

Cost per ton of emission reduction decreases as gasoline throughput increases. The largest facilities, those with gasoline throughput of greater than 2 million gallons per year, showed a financial benefit based on substantial estimated fuel savings from this measure.

The cost per ton can decrease by allowing GDFs to make Phase I EVR modifications gradually rather than at a fixed time (MDEP 2012). The cost-effectiveness of applying CARB-compliant Stage I

EVR in HA 212 will depend upon GDF throughput, whether there is a low gasoline throughput exemption, and the extent to which any existing control equipment is already in compliance.

11.8 IMPLEMENTATION OF CONTINGENCY MEASURE

AQR Section 102.7(c)(5) will require GDF owners or operators to begin meeting CARB EVR certification requirements and CARB executive orders for certain GDF equipment 180 days after DAQ issues a notice stating that the rule applies, then fully meet the requirements after two years. If EPA determines that HA 212 has failed to meet its attainment date, DAQ will issue such a notice, as appropriate, within 60 days of EPA's final action. No additional rulemaking action is necessary for DAQ to trigger applicability (AQR Section 102.7(c)(5)). Because CARB EVR is not currently required, and no additional rulemaking action is necessary for DAQ to trigger AQR Section 102.7(c)(5), the rule satisfies Section 172(c)(9) of the Act, which requires that contingency measures take effect without further action by the state or the EPA Administrator (42 U.S.C. 7502).

12.0 CONFORMITY AND MOTOR VEHICLE EMISSIONS BUDGET

Transportation conformity is required under Section 176(c) of the Act, which prohibits the federal government from engaging in, supporting, or providing financial assistance for licensing, permitting, or approving any transportation project unless it conforms to the SIP. Conforming to the SIP means the transportation projects do not create new violations of the NAAQS, do not increase the frequency or severity of NAAQS violations, and do not delay timely attainment of the NAAQS.

EPA established implementation rules in 40 CFR Part 51, Subpart T, and 40 CFR Part 93. For nonattainment areas required to demonstrate reasonable further progress and attainment, EPA requires the SIP to document the MVEB on which the attainment demonstration is based. The amount of mobile source emissions used in the attainment demonstration becomes the emissions budget for highway and transit vehicles. Emissions from future transportation projects must stay within this budget. Transportation plans, programs, and projects funded or approved under U.S.C. Title 23 or the Federal Transit Act must conform to the on-road MVEBs specified in the applicable SIP. In this case, 40 CFR Part 93.118 provides the criteria and procedures for MVEBs.

The MVEB establishes a cap on motor vehicle-related emissions that the predicted transportation system emissions from new transportation projects cannot exceed. The emissions budget serves as a ceiling on emissions for the estimation year and all subsequent years, until either a different budget is defined for another year or a SIP revision modifies the budget. Unless the SIP clearly indicates otherwise, the estimate of future transportation network emissions used in a milestone or attainment demonstration acts as the MVEB.

To create the MVEB, DAQ added a safety margin of 2 tpd of both VOC and NO_x to the on-road mobile sector 2023 projected emissions inventory (Table 26).

Table 26. Safety Margin for On-road Mobile Source Emissions in MVEB

Parameter	2023 Unadjusted Emissions (tpd)	Safety Margin (tpd)	2023 Adjusted Emissions (tpd)	Percent Change
On-road mobile VOC emissions	17.01	2.00	19.01	11.8%
On-road mobile NO_x emissions	19.15	2.00	21.15	10.4%

DAQ also added an amount equal to banked ERCs to the VOC and NO_x point source inventories (Table 27).

Table 27. Point Source Adjustments to MVEB for ERCs

Parameter	2023 Unadjusted Emissions (tpd)	ERC Adjustment (tpd)	2023 Adjusted Emissions (tpd)	Percent Change
Point source VOC emissions	1.32	0.05	1.37	3.8%
Point source NO_x emissions	3.23	0.92	4.15	28.5%

Table 28 displays the total MVEB. Once approved by EPA, these emissions values will be used in future transportation conformity analyses.

Table 28. VOC and NO_x MVEB for 2015 Ozone NAAQS

Source Category	2023 MVEB VOC (tpd)	2023 MVEB NOx (tpd)
Point source	1.37	4.12
Nonpoint source	58.29	4.01
On-road mobile	19.01	21.15
Non-road mobile	24.17	22.98
Airports (commercial & federal)	2.62	15.52
Locomotives	0.03	0.66
ERC	0.05	0.92
Totals	**105.54**	**69.36**

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ATTACHMENT A:

Emissions Inventory

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November 2023

2017 and 2023 Emission Inventories for the Clark County Ozone SIP

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1.0 Introduction

In 2018, the US Environmental Protection Agency (EPA) designated a portion of Clark County, Nevada as a Marginal Nonattainment area under the 2015 ozone National Ambient Air Quality Standard (NAAQS) of 70 parts per billion (ppb) (Federal Register, 2018). The nonattainment boundary is defined as the Las Vegas Valley (LVV), hydrographic area 212 (HA 212), as recommended by the Nevada Division of Environmental Protection (NDEP) and Clark County (2018). Due to continued exceedances of the standard through 2020, the EPA has reclassified the Clark County Nonattainment Area (HA 212) to Moderate with an attainment date of August 3, 2024, based on the 2021-2023 8-hour ozone Design Value (DV) (Federal Register, 2022; 2023). Therefore, the area's attainment year is 2023.

To support an ozone attainment demonstration for the Moderate State Implementation Plan (SIP), Ramboll is conducting a complete photochemical modeling study and ancillary weight-of-evidence analyses. The Comprehensive Air quality Model with extensions (CAMx) is used for this purpose (Ramboll, 2022a).

This memorandum describes the methodologies and technical details that the Clark County Department of Environment and Sustainability (DES) and Ramboll used to develop the 2017 base year and 2023 future year HA 212 emissions inventory for the moderate area SIP.

2.0 2017 and 2023 Ozone Season Day Emissions Inventory

We developed 2017 base year and 2023 future year anthropogenic ozone season weekday emission estimates for ozone precursors within HA 212 only (collectively referred to as the 2015 Ozone NAAQS SIP Inventory). The ozone season day emissions inventory is defined as an average day emissions inventory for a typical ozone season work weekday (not a holiday). Figure 2-1 shows the Clark County boundary and HA 212 within Clark County. The figure also shows a grid boundary covering HA 212 used to generate emission estimates for certain source sectors using the Sparse Matrix Operator Kernel Emissions (SMOKE; UNC, 2020) processing system. The source categories included in the 2015 Ozone NAAQS SIP Inventory include all anthropogenic emissions categories: stationary point sources, stationary nonpoint (area) sources, on-road mobile sources, nonroad mobile sources, airports, and locomotive sources. Emissions from railways, residential wood combustion, and agriculture/livestock were included in the nonpoint source category. The primary data sources for the inventory were local-specific activity data, the 2017 Emissions Modeling platform (EMP) based on the 2017 National Emissions Inventory (EPA, 2022a), and the 2016v2 EMP 2023 projections (EPA, 2022b).

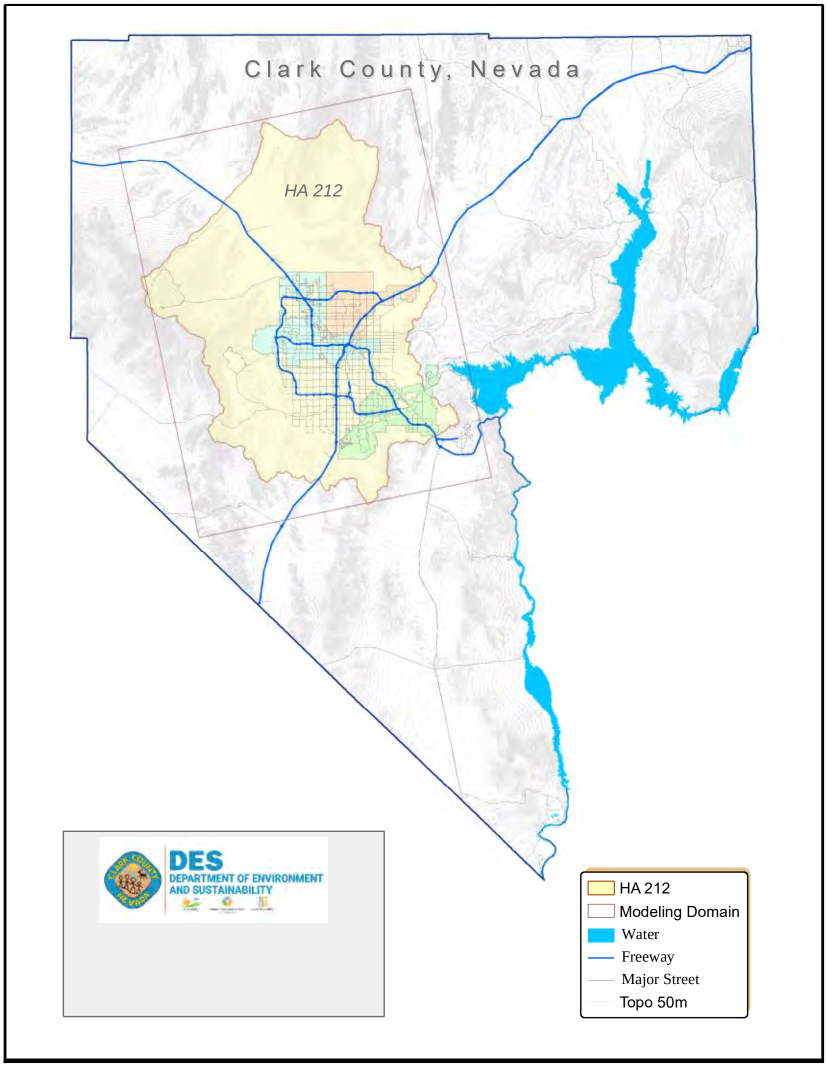


Figure 2-1. Clark County and the ozone nonattainment area (HA 212). The box covering **HA 212 labeled "Modeling Domain" refers to the SMOKE emissions processing** grid used to estimate HA 212 ozone season weekday emissions for certain source sectors.

The 2015 Ozone NAAQS SIP Inventory includes the effects from applicable on-the-books regulations such as the Tier 3 Motor Vehicle Emissions and Fuel Standards,[1] Final Rule for Control of Emissions of Air Pollution From Nonroad Diesel Engines and Fuel,[2] and Consumer Products: National Volatile Organic Compound Emissions Standards.[3]

[1] https://www.epa.gov/regulations-emissions-vehicles-and-engines/final-rule-control-air-pollution-motor-vehicles-tier-3, Accessed Online in September 2022.

[2] https://www.epa.gov/regulations-emissions-vehicles-and-engines/final-rule-control-emissions-air-pollution-nonroad, Accessed Online in September 2022.

[3] https://www.epa.gov/stationary-sources-air-pollution/consumer-products-national-volatile-organic-compound-emission, Accessed Online in September 2022.

Table 2-1 and Table 2-2 show 2017 and 2023 HA 212 emission estimates by major source category, representing a typical ozone season weekday. On-road and nonroad mobile sectors are the dominant sources for NOx, followed by airports. The NOx emissions decline in 2023 is primarily due to turnover in nonroad and on-road fleets. The nonpoint sector is the dominant anthropogenic source for VOCs followed by on-road and nonroad mobile sources. The sections below describe each source category in detail.

Table 2-1. Summary of HA 212 ozone season weekday VOC emissions (tons per day, TPD).

Source Category	2017 Base VOC (tpd)	2023 Base VOC (tpd)
Point source	1.25	1.32
Nonpoint source	56.05	58.29
On-road mobile	24.43	17.01
Non-road mobile	24.03	24.17
Airports (commercial & Federal)	1.94	2.62
Locomotives	0.04	0.03
ERC		0.05
Total	**107.73**	**103.49**

Table 2-2. Summary of HA 212 ozone season weekday NOx emissions (tons per day, TPD).

Source Category	2017 Base NOx (tpd)	2023 Base NOx (tpd)
Point source	2.92	3.23
Nonpoint source	6.15	4.01
On-road mobile	36.32	19.15
Non-road mobile	36.98	22.98
Airports (commercial & Federal)	11.90	15.52
Locomotives	0.80	0.66
ERC		0.92
Total	**95.07**	**66.47**

3.0 On-road Mobile Source Emissions

On-road mobile sources include automobiles, motorcycles, buses, and trucks traveling on local roads, and state and national highways. DES ran the EPA's MOtor Vehicle Emissions Simulator, version 3.1 (MOVES3.1, the latest release[4]), in inventory mode to develop the on-road mobile source emissions estimates for HA 212.

3.1 MOVES Inputs

MOVES3.1 includes 13 source types (Table 3-1) and four roadway types (Table 3-2). DES developed updated county-specific MOVES input databases for the 2017 base year and the

[4] https://www.epa.gov/moves/latest-version-motor-vehicle-emission-simulator-moves.

2023 future year based on the most recent information. Once the databases were generated, the HA 212 sub-county input databases were also developed based on either actual activity data or spatial surrogates. DES then ran MOVES3.1 with the databases for only HA 212 to generate the ozone inventories for the on-road source category.

Table 3-1. MOVES source types.

Source Type ID	MOVES Source Type Name
11	Motorcycle
21	Passenger Car
31	Passenger Truck
32	Light Commercial Truck
41	Other Buses
42	Transit Bus
43	School Bus
51	Refuse Truck
52	Single Unit Short-haul Truck
53	Single Unit Long-haul Truck
54	Motor Home
61	Combination Short-haul Truck
62	Combination Long-haul Truck

Table 3-2. Map of Highway Performance Monitoring System (HPMS) road types to MOVES road types.

<table>
<tr><th>HPMS Road Type</th><th>MOVES Road Type</th></tr>
<tr><td>11: Rural Principal Arterial – Interstate</td><td>2: Rural Restricted Access</td></tr>
<tr><td>13: Rural Principal Arterial - Other</td><td rowspan="5">3: Rural Unrestricted Access</td></tr>
<tr><td>15: Rural Minor Arterial</td></tr>
<tr><td>17: Rural Major Collector</td></tr>
<tr><td>19: Rural Minor Collector</td></tr>
<tr><td>21: Rural Local System</td></tr>
<tr><td>23: Urban Principal Arterial – Interstate</td><td rowspan="2">4: Urban Restricted Access</td></tr>
<tr><td>25: Urban Principal Arterial – Other Freeways</td></tr>
<tr><td>27: Urban Principal Arterial – Other</td><td rowspan="4">5: Urban Unrestricted Access</td></tr>
<tr><td>29: Urban Minor Arterial</td></tr>
<tr><td>31: Urban Collector</td></tr>
<tr><td>33: Urban Local System</td></tr>
</table>

The key MOVES inputs include vehicle fleet activity data such as vehicle miles traveled (VMT), vehicle population by vehicle source type (or vehicle class), fleet age distribution, fuel parameters, and inspection and maintenance (I/M) programs.

3.1.1 Clark County Vehicle Classification Study

Since vehicle classification is a crucial component for developing an on-road emission inventory, DES completed a vehicle classification study in June 2018. The study used 2014-2016 traffic count data collected by the Nevada Department of Transportation (NDOT) and included an on-road license plate survey at selected roadway locations. The collected license plate numbers were matched to vehicle identification numbers (VIN), then decoded to obtain vehicle attributes that allowed DES's contractor to classify cars versus light-duty trucks. The primary products of the vehicle classification study included VMT mix and temporal profiles, which were incorporated into the 2017 MOVES input database. The MOVES temporal profiles included monthly, weekly, and hourly traffic profiles.

<u>VMT Mix Profiles</u>

Figure 3-1 shows the VMT mix profiles from the DES study by MOVES road type. Rural Restricted Access (Road Type 2) has the highest amount of heavy-duty VMT (24%), which decreases from left to right in the figure: from Road Type 2 to Rural Unrestricted Access (Road Type 3) to Urban Restricted Access (Road Type 4) to Urban Unrestricted (Road Type 5).

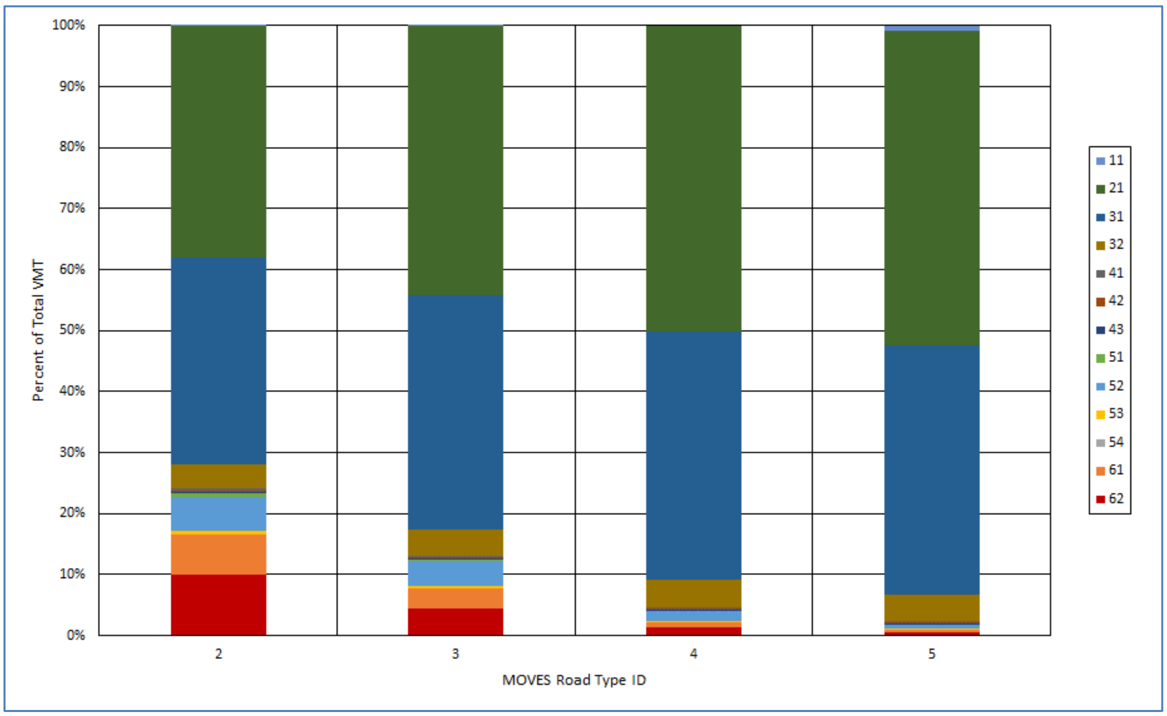


Figure 3-1. Summary of VMT mix by vehicle type on each MOVES road type. Vehicle types are listed in Table 3-1.

<u>Monthly Traffic Profiles</u>

Figure 3-2 displays the monthly VMT profiles for MOVES. The MOVES model distributes annual VMT to monthly totals using the monthly VMT fractions shown in Figure 3-2. Clark County's monthly variation does not indicate a strong seasonal influence on VMT. These monthly variations are based on the NDOT traffic counts during 2014-2016. NDOT has continuous traffic counters operating throughout the year.

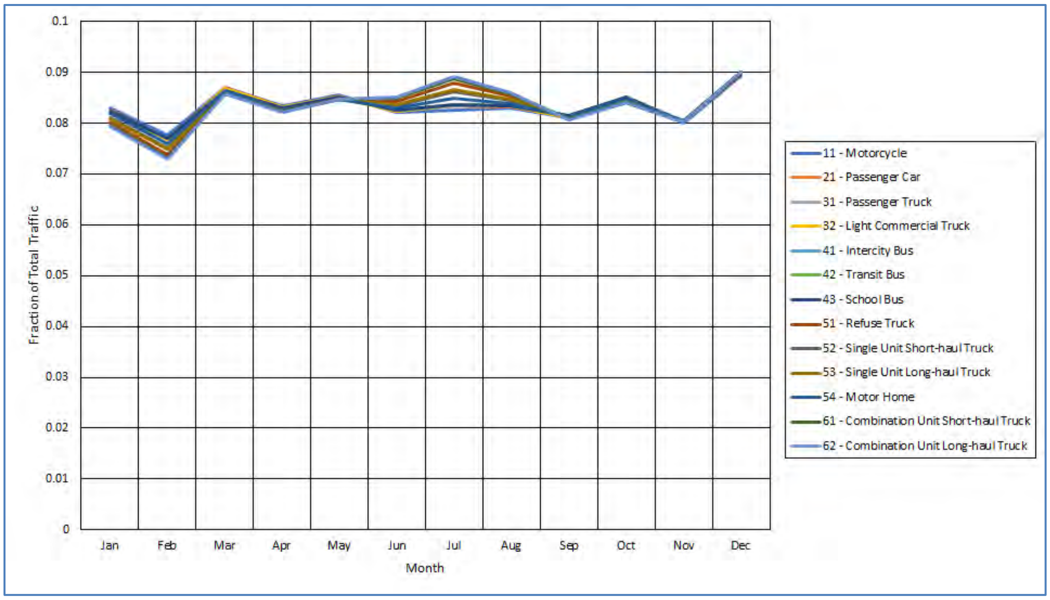


Figure 3-2. MOVES monthly VMT fractions for Clark County, NV.

Weekly Traffic Profiles

The day-of-week profiles in MOVES apportion weekly VMT to two periods of the week: "weekday," consisting of 5 days, and "weekend," consisting of 2 days. Figure 3-3 shows a sample of the profiles for passenger cars. The ratio of weekday to weekend VMT grows from left to right, moving from Rural (Road Types 2 and 3) to Urban (Road Types 4 and 5). This pattern of higher weekday VMT on urban roads and unrestricted roads was generally true for all the source types.

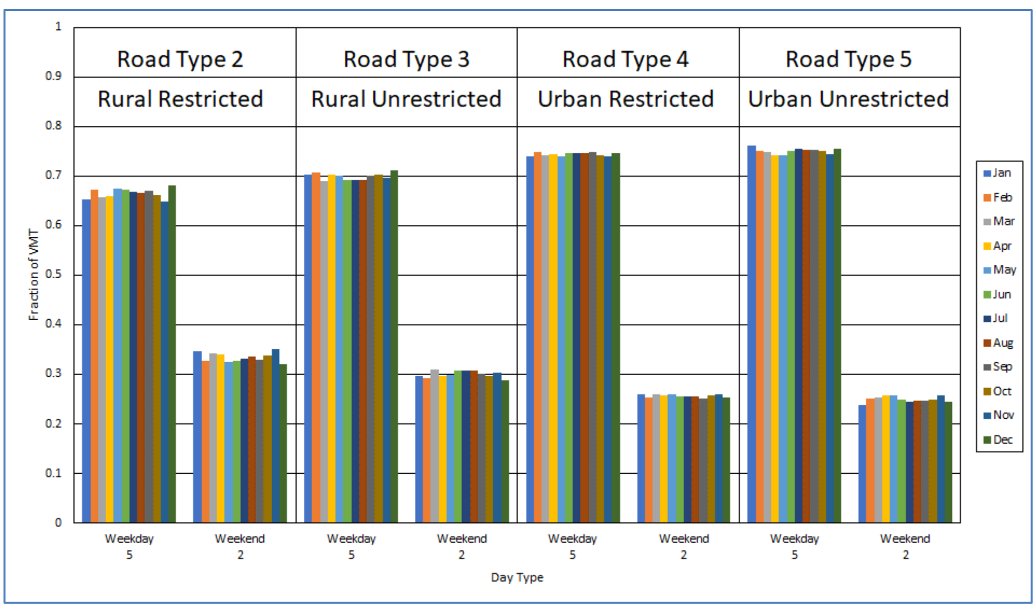


Figure 3-3. An Example of MOVES VMT fractions (passenger cars) by day-of-week type.

<u>Hourly Traffic Profiles</u>

Figure 3-4 shows a sample of MOVES hourly VMT fractions for passenger cars traveling on weekdays (solid line series) and weekends (broken line series) in Clark County for each of the four MOVES road types. On weekdays, the two Urban Road Types—4 (grey) and 5 (yellow)—have prominent morning peaks in the VMT fractions. Weekend profiles on all road types reach their high point midday, i.e., between the hours of about noon to 4 PM.

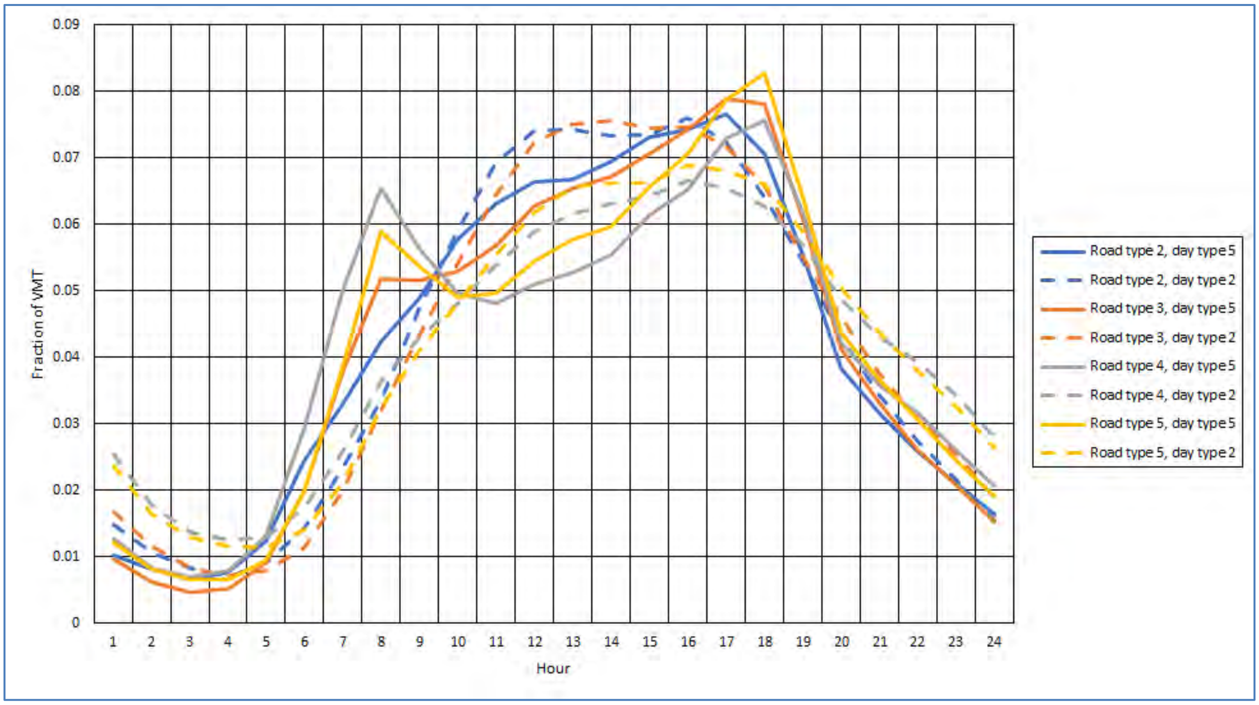


Figure 3-4. An example of MOVES hourly VMT Fractions (passenger cars).

3.1.2 Other MOVES Inputs

Activity data for each vehicle type, such as VMT and vehicle population, are important inputs for MOVES. VMT data for the base year (2017) inventory are derived from NDOT's 2017 annual Highway Performance Monitoring System (HPMS) reports. Per special request, NDOT also provided DES with VMT data for the HA 212 sub-county area, which was used for on-road inventory development.

The MOVES model requires annual or daily VMT by vehicle type. Using the VMT mix information developed from the Clark County Vehicle Classification Study, DES generated annual VMTs for each vehicle source type for HA 212. Table 3-3 shows Clark County 2017 annual VMTs by function class within HA 212 from NDOT.

For urban road types, 2023 VMT was projected from 2017 using growth factors from forecasts derived from travel demand modeling conducted by the Regional Transportation Commission of Southern Nevada (RTC). For rural road types, a linear regression projection from historical NDOT HPMS reports was used to project VMT. Table 3-4 lists annual VMT by source type for the two modeling years.

Table 3-3. Clark County 2017 annual VMT by function class within HA 212.

Function Class	2017 Annual VMT
Rural Interstate	37,956,020
Rural Other Principal Arterial	71,177,655
Rural Minor Arterial	0
Rural Major Collector	45,745,974
Rural Minor Collector	1,218,372
Rural Local	8,512,560
Urban Interstate	3,158,264,116
Urban Other Freeways and Expressways	1,509,145,790
Urban Other Principal Arterial	2,045,321,410
Urban Minor Arterial	3,937,878,139
Urban Collector	1,617,429,935
Urban Local	4,118,471,242
Annual Total	16,551,121,213

Table 3-4. Clark County annual VMT by vehicle type within HA 212.

Source Type ID	Source Type Name	2017	2023
11	Motorcycle	93,203,739	106,807,127
21	Passenger Car	8,396,862,937	9,622,412,293
31	Passenger Truck	6,754,358,072	7,740,178,521
32	Light Commercial Truck	722,814,819	828,311,984
41	Other Buses	45,433,736	50,840,909
42	Transit Bus	28,032,592	30,496,138
43	School Bus	21,850,000	27,891,008
51	Refuse Truck	12,033,030	13,789,290
52	Single Unit Short-haul Truck	202,484,000	232,037,196
53	Single Unit Long-haul Truck	10,078,340	11,549,306
54	Motor Home	1,640,285	1,879,689
61	Combination Short-haul Truck	140,293,750	160,770,077
62	Combination Long-haul Truck	122,035,913	139,847,450
Total:		16,551,121,213	18,966,810,989

DES derived the vehicle type population data for the entire county primarily from the Nevada Department of Motor Vehicle (DMV) registration database. Adjustments were made for transit buses based on data obtained from the RTC and for school bus populations based on reports from the online magazine SchoolBus. Vehicle population estimates for combination short-haul and long-haul trucks were based on MOVES3's default database. The vehicle populations by source type were projected from 2017 to 2023 using surrogates such as human population for light duty vehicles, and VMT for heavy duty trucks. For the HA 212 sub-county area, vehicle population by source type was adjusted from county-level using human population as a surrogate. Based on census data for human population distribution, DES assumed that the source type population within HA 212 is about 95 percent of the total source type population of Clark County. Table 3-5 lists the source type populations used in the model for the years 2017 and 2023.

Table 3-5. Clark County vehicle population within HA 212.

Source Type ID	Source Type Name	2017	2023
11	Motorcycle	40,367	45,405
21	Passenger Car	679,162	763,922
31	Passenger Truck	529,309	595,367
32	Light Commercial Truck	56,644	63,713
41	Other Buses	355	399
42	Transit Bus	797	856
43	School Bus	1,859	2,091
51	Refuse Truck	601	686
52	Single Unit Short-haul Truck	15,575	17,797
53	Single Unit Long-haul Truck	1,102	1,260
54	Motor Home	865	988
61	Combination Short-haul Truck	4,285	4,897
62	Combination Long-haul Truck	6,891	7,875
Total:		1,337,813	1,505,256

MOVES also requires input from hoteling activity, which refers to the hours spent idling by drivers of diesel long-haul combination trucks during mandatory rest periods. MOVES accounts for idling and auxiliary power unit (APU) use as separate emission processes, in addition to truck operation on roadways. Since no local specific hoteling hours are available, hoteling hours were based on MOVES3.1 default.

Ambient temperature and humidity data were based on the meteorological data collected at Harry Reid International Airport (LAS) in 2017. Table 3-6 presents the average hourly temperature and humidity data used in the MOVES database for July 2017.

Table 3-6. Average hourly temperature and humidity at McCarran International Airport for July 2017.

Hour	Temperature (F)	Humidity (%)
1	90.7	25.7
2	89.4	26.8
3	88.3	28.0
4	87.0	29.7
5	86.1	31.1
6	87.5	30.0
7	90.3	27.7
8	92.3	28.5
9	94.9	25.5
10	97.3	23.9
11	99.6	22.1
12	101.7	19.5
13	103.1	18.4
14	103.7	17.9
15	104.3	16.4
16	104.1	16.5
17	104.1	16.3
18	102.8	16.6
19	100.8	18.1
20	98.8	19.9
21	96.9	21.3
22	95.2	22.1
23	93.5	23.4
24	91.9	25.6

The DMV provided vehicle registration data for Clark County by model year and vehicle type, which DES used to generate the vehicle population and vehicle age distribution inputs. The age distributions for 2017 were based on the vehicle registration data from DMV for light-duty vehicle types; age distributions for heavy-duty vehicle types were exported from the MOVES3.1 default database. However, DES found a better source of data for age distribution from a national project conducted by the Coordinated Research Council (CRC). The project performed VIN decoding of 2017 county-specific registration data from IHS Markit, a global information services provider. The age distributions derived from the VIN-decoding project have been used by EPA in their 2016 modeling platform and 2017 NEI development. EPA purchased the county-specific data from IHS Markit for the entire U.S. DES believes that the age distributions in the 2017 NEI are more robust and were therefore used in Clark County's on-road inventory.

EPA recently developed an age distribution projection tool for the 2016v2 modeling platform that includes a new method to ensure the dip in light-duty vehicle sales during the 2008–09 recession is reflected for the same model years at a future time. In other words, the tool adjusts the age distributions of light-duty source types from the base year to future years. DES used this new age-distribution projection tool to adjust the light-duty source types from the base year of 2017 to the future year of 2023. The future-year age distributions for heavy-duty source types were kept the same as those in the base year of 2017, consistent with the assumption used in the 2016v2 modeling platform.

CRC also sponsored a number of projects aimed at improving the on-road portion of the NEI. Vehicle speed distribution is a crucial component of on-road emission inventories. For the Clark County 2017 MOVES database, the average vehicle speed distributions from 16 MOVES speed bins for each vehicle type were based on the CRC-sponsored project A-100, which used StreetLight Vehicle Telematics Data. DES used the same speed distributions for the future year of 2023, consistent with the assumption used in the 2016v2 modeling platform.

DES also used fuel parameters from the MOVES3.1 default database. Both gasoline and diesel sulfur levels are required to meet EPA requirements for low sulfur content as part of the Tier 2 standard (before 2017) or the Tier 3 standard (after 2017). Nevada caps the fuel Reid vapor pressure in Clark County at 9.0 pounds per square inch (psi), with a 1.0-psi waiver for ethanol-blended fuels.

Information regarding vehicle I/M programs is another important input for the MOVES model. In the Las Vegas Valley, the state I/M program requires an annual two-speed idle test for 1995 and older vehicles, and on-board diagnostics checks (exhaust and evaporative) for 1996 and newer vehicles. In the past, the I/M program exempted a new vehicle from emissions testing for the first 2 years. During the 2021 legislative session, Nevada Bill AB 349 changed the I/M grace period from 2 years to 3 years. DES incorporated this information into MOVES modeling using a 2-year grace period for 2017 and a 3-year grace period for 2023.

3.2 On-road Mobile Emissions Estimates

Table 3-7 shows Clark County's summer weekday on-road emission estimates for 2017 and 2023. DES ran MOVES3.1 for a single July weekday using meteorological data in Table 3-6 to represent typical summertime on-road NOx and VOC emissions. Emission estimates for both ozone precursors significantly decrease from 2017 to 2023 due to fleet turnover with the implementation of stringent emissions control limits such as Tier 3 standards, which phase-in starting in 2017.

Table 3-7. Clark County on-road mobile emissions in July (TPD) within HA 212.

Pollutant	2017	2023
VOC	24.43	17.01
NO_x	36.32	19.15

4.0 Nonroad Source Emissions

Nonroad mobile sources include a wide variety of motorized equipment types that either move under their own power off the roadway network or can be moved from site to site. The nonroad mobile source 2017 and 2023 emissions estimates were taken from the 2017 EMP and the 2016v2 EMP 2023 projections, respectively, which are based on the nonroad module of MOVES3 (EPA, 2020).

To develop HA 212 sub-county ozone season weekday emissions estimates, SMOKE was run for weekdays of a single week (Monday through Friday) in July (without a holiday) on a grid covering the nonattainment areas with 4 km grid spacing (Figure 2-1) using monthly nonroad emissions data by Source Classification Code (SCC) in the FF10 flat data file format. The total emission estimates within the modeling domain were summed for NOx and VOC and averaged over all five weekdays. Several ancillary (e.g., cross-references) data files are required when running SMOKE. We used the ancillary files from respective EMPs. The resulting HA 212 nonroad emissions are provided by SCC in Appendix A. Table 4-1 shows July 2017 and 2023 average weekday total nonroad emissions within HA 212.

Table 4-1. Clark County nonroad emissions in July (TPD) within HA 212.

Pollutant	2017	2023
VOC	24.03	24.17
NO_x	36.98	22.98

5.0 Nonpoint Source Emissions

Nonpoint sources are stationary sources that fall below point source reporting levels and are too numerous or small to identify individually, e.g., small-scale industrial or residential operations that use emission-generating materials or processes. We accessed the 2017 and 2023 nonpoint emissions from the 2017 EMP and the 2016v2 EMP 2023 projections, respectively, to develop the Clark County ozone HA 212 inventory. The nonpoint source category includes locomotive, volatile chemical products (VCP), commercial combustion, asphalt paving, residential wood combustion, and other area sources. The 2016v2 EMP uses EPA's new approach and data to derive emissions for VCP sources; the 2017 EMP and previous emissions inventories reported VCP emissions based on an older methodology. To obtain 2017 VCP estimates based on a consistent methodology, we linearly interpolated VCP emissions reported in the 2016v2 EMP between 2016 and 2023 instead of using emissions from the 2017 EMP. Table 5-1 provides a detailed overview of annual VOC emissions from VCP sources in Clark County for the years 2016, 2017 (interpolated), and 2023.

Table 5-1. Clark County VCP VOC emissions by SCC interpolated to 2017.

SCC	SCC Description	2016 (tons/year)	2023 (tons/year)	Interpolated 2017 (tons/year)
2401001000	Architectural Coatings	1,518	1,683	1,542
2401100000	Industrial Maintenance Coatings	745	826	757
2402000000	Paint Strippers	1,226	1,359	1,245
2420000000	Dry Cleaning	24	24	24
2425000000	Graphic Arts	842	934	855
2460100000	C&C: Cosmetics and Toiletries	47	52	48
2460110000	Personal Care Products	3,676	4,076	3,733
2460190000	Personal Care Products	106	118	108
2460200000	C&C: Cleaning Products; Household	411	456	417
2460290000	Household Cleaning Products: Detergents & Soaps and General Cleaners	3,603	3,995	3,659
2460500000	C&C: Coatings and Related Products	472	524	480
2460600000	C&C: adhesives and sealants	1,571	1,742	1,595
2460900000	C&C: Misc. Products (not otherwise covered)	40	44	40
2461021000	Cutback Asphalt	303	303	303
2461022000	Emulsified Asphalt	1,226	1,226	1,226
2461800000	Pesticide Application	170	188	172
2461850000	Ag Pesticide	1	1	1
Total:		**15,980**	**17,551**	**16,205**

SMOKE was run on the HA 212 grid (Figure 2-1) for weekdays of a single week (Monday through Friday) in July (without a holiday) to generate ozone season weekday emission estimates using annual nonpoint emissions data by SCC in FF10 flat data file formats. The total emission estimates within the modeling domain were summed for NOx and VOC and averaged over all five weekdays. When running SMOKE, several ancillary (e.g., cross-references) data files are required. We used the ancillary data files from respective EMPs. The resulting HA 212 nonpoint emissions are provided by SCC in Appendix A. Table 5-2 shows July 2017 and 2023 average weekday total locomotive emissions within HA 212. Similarly, Table 5-3 shows July 2017 and 2023 average weekday emissions for other nonpoint sources within HA 212.

Table 5-2. Clark County locomotive July weekday emissions (TPD) within HA 212.

Pollutant	2017	2023
VOC	0.04	0.03
NO_x	0.80	0.66

Table 5-3. Clark County nonpoint emissions in July (TPD) within HA 212.

Pollutant	2017	2023
VOC	56.05	58.29
NO_x	6.15	4.01

6.0 Point Source Emissions

Point sources are larger stationary sources that emit above mandatory reporting levels and must be permitted. Examples include power plants, industrial boilers, and various other industrial/commercial facilities. Clark County's point source inventory includes all Title V stationary and all minor sources with the potential to emit at least 10 tons of VOCs or 25 tons of NOx that are located within HA 212. Point source 2017 emissions inventories were obtained from 2017 annual reports submitted by individual stationary sources and 2023 emissions were obtained from the Technical Support Document of Second Maintenance Plan for the 1997 8-hour Ozone NAAQS (DES, 2021a). Point source emission inventories were developed from either data collected by direct on-site measurements or calculated using EPA emission factors and activity data. Emissions from all minor sources emitting less than 10 tons of VOCs or 25 tons of NOx were included in the nonpoint source category.

Table 6-1 provides the overall NOx and VOC point source emissions for 2017 and 2023. The resulting HA 212 point source emissions by individual unit are listed in Appendix B.

Table 6-1. Clark County point source emissions within HA 212 (tons per summer day).

Pollutant	2017	2023
VOC	1.25	1.32
NO_x	2.92	3.23

7.0 Commercial Aviation

Commercial aviation within HA 212 covers emissions from three airports: Harry Reid (McCarran) International Airport, North Las Vegas Airport, and Henderson Executive Airport. The 2017 actual and 2023 future year emissions for commercial aviation were provided by the Clark County Department of Aviation (DOA). The emission inventories were developed using the Federal Aviation Administration's Aviation Environmental Design Tool (AEDT), Version 3b. DOA calculated design day emissions using the default meteorology in AEDT. The design day was in October, so DOA developed correction factors to account for the differences in meteorology between the design day and a typical summer weekday. These correction factors were applied to the emission inventories for all the airports. Table 7-1 presents 2017 and 2023 emissions for commercial aviation.

Table 7-1. Commercial aviation emissions (tons per summer day).

	2017		2023	
Airport	NOx	VOC	NOx	VOC
Harry Reid (McCarran) International Airport	10.95	1.11	12.55	1.11
North Las Vegas Airport	0.24	0.38	0.23	0.37
Henderson Executive Airport	0.21	0.21	0.22	0.22
Total	11.40	1.72	13.01	1.72

8.0 Federal Aviation

Federal aviation emissions in HA 212 occur mostly at Nellis Air Force Base. Table 8-1 presents 2017 actual and 2023 projected emissions from aircraft operations obtained from Clark County's 1997 8-hour Ozone Second Maintenance Plan (DES, 2021a).

Table 8-1. Federal aviation emissions for 2017 (actual) and 2023 (projected).

	2017		2023	
Airport	NOx	VOC	NOx	VOC
Nellis Air Force Base	0.50	0.24	2.03	0.84
Air Force Training Project			0.49	0.08
Total	0.50	0.24	2.52	0.92

9.0 Banked Emission Reduction Credits (ERC)

Emission Reduction Credits (ERCs) may be granted, under strict guidelines, upon request by an emissions source that voluntarily reduces emissions beyond required levels of control. ERCs may be sold, leased, banked for future use, or traded in accordance with applicable regulations. When used to offset emissions, they are permanently retired. ERCs are intended to provide an incentive for reducing emissions and to establish a framework to promote a market-based approach to regulating air pollution. Tables 9-1 and 9-2 outline the ERCs currently banked in Clark County for HA 212.

Table 9-1. ERC Balance for NOx within HA 212.

Owner ID – Name	ERC Balance
4 - CERTAIN TEED CORPORATION	16.5
3 - CHEMICAL LIME COMPANY	78.7
347 - MORGAN ADHESIVES COMPANY / MACTAC	1
99 - NEVADA READY MIX	60.4
477 - NV ENERGY	13.78
279 - SILVER STATE MATERIALS CORP.	9
19 - TITANIUM METALS CORP. (TIMET)	157.8
Total (TPY)	337.18
Total (TPD)	0.92

Table 9-2. ERC Balance for VOC within HA 212.

Owner ID – Name	ERC Balance
4 - CERTAIN TEED CORPORATION	0.13
347 - MORGAN ADHESIVES COMPANY / MACTAC	17.5
99 - NEVADA READY MIX	1.3
477 - NV ENERGY	0.08
279 - SILVER STATE MATERIALS CORP	0.7
Total (TPY)	19.71
Total (TPD)	0.05

10.0 Quality Assurance of Emissions

We performed thorough Quality Assurance (QA) and Quality Control (QC) checks of emissions following the procedures developed by WRAP (Adelman, 2004) for all source categories. We leveraged SMOKE's advanced quality assurance features that include error logs when emissions are dropped or added during emissions processing. We carefully reviewed SMOKE log files for each processing stream and resolved any errors or critical warning messages before making a final SMOKE run. The QA activities of emissions data for each source category are described below.

For on-road mobile sources, most input datasets were generated from a locally specific vehicle study, and these datasets were carefully reviewed and checked. Some input datasets were submitted to EPA through the Emissions Inventory System (EIS), which includes several QA and QC checks. The MOVES model also includes internal checks and we made sure that all input datasets were properly imported into the MySQL database with all green checks showing before running the model. The output database was carefully reviewed, and we made sure there were no error messages. The emissions outcomes were reviewed and compared to other inventory data such as inventories from the NEI, different years, and other counties for reasonableness and consistency.

For nonroad and nonpoint sources, the primary data sources for the inventory were the 2017 Emissions Modeling platform (EMP) based on the 2017 NEI (EPA, 2022a), and the 2016v2 EMP 2023 projections (EPA, 2022b). EPA performed QA/QC checks on these datasets, and we thoroughly reviewed them. We used these inventories and the SMOKE modeling system for the 2016v2 platform without modification to develop emissions for HA 212. The emission outcomes were compared to those from NEI and other counties for reasonableness and consistency. The spatial distribution of emissions was checked with gridded emissions maps. Figures 10-1 and 10-2 illustrate the spatial distribution of NOx and VOC emissions in both 2017 and 2023 for these sectors. The emissions maps consistently align with the distribution of population and housing density within HA 212, showcasing correct spatial allocation of emissions. The point source emission inventories submitted by facilities were checked by the DES compliance staff following procedures outlined in the Emissions Inventory Report Review and Audit Process (DES, 2021b).

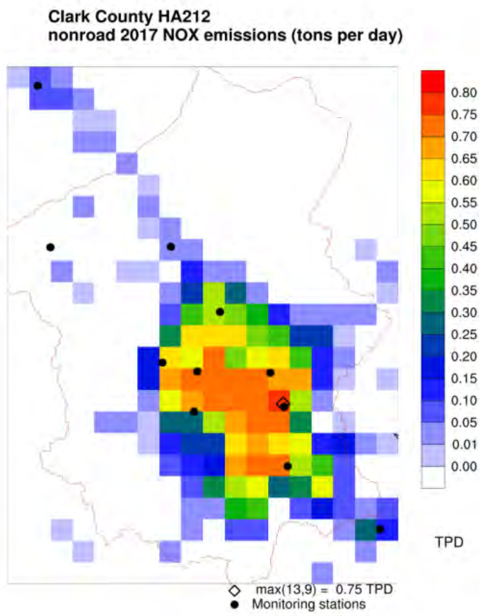
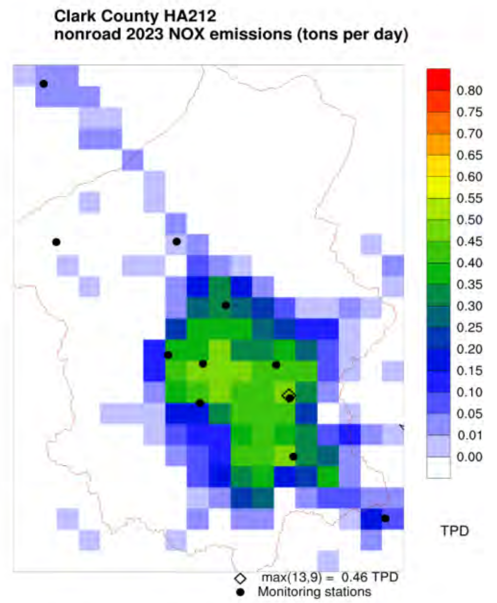
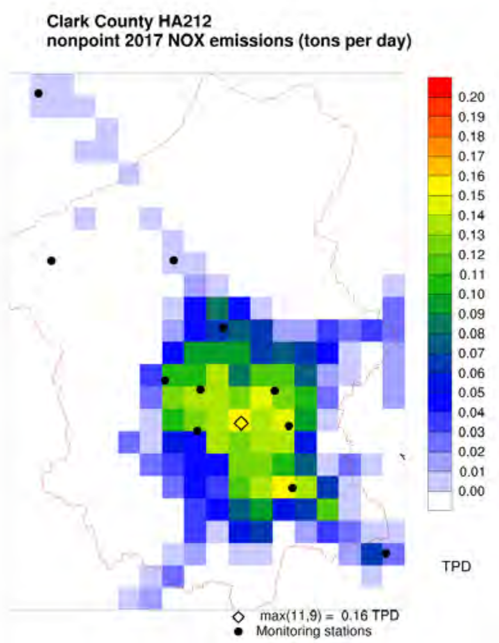
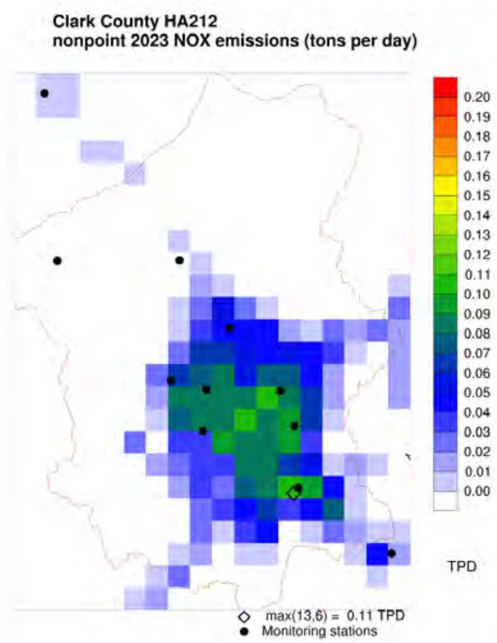
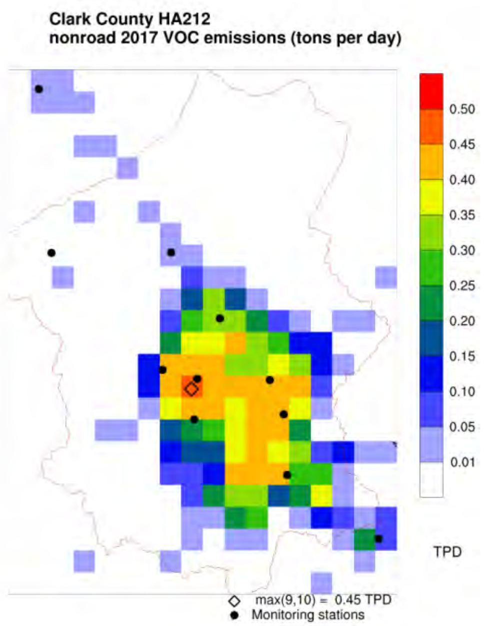
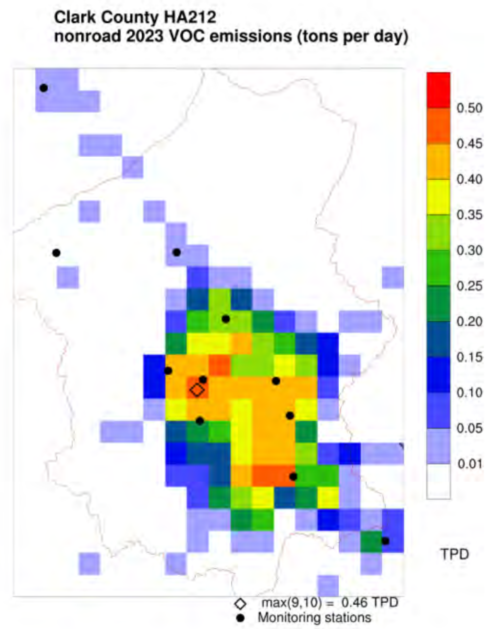
<table>
<tr><th>NOx</th><th>2017</th><th>2023</th></tr>
<tr><td>Nonroad</td><td>
</td><td>
</td></tr>
<tr><td>Nonpoint</td><td>
</td><td>
</td></tr>
</table>

Figure 10-1. July weekday average NOx emissions for nonroad (top row) and nonpoint (bottom row) sectors presented for the years 2017 (left column) and 2023 (right column).

<table>
<tr><th>VOC</th><th>2017</th><th>2023</th></tr>
<tr><td>Nonroad</td><td>
</td><td>
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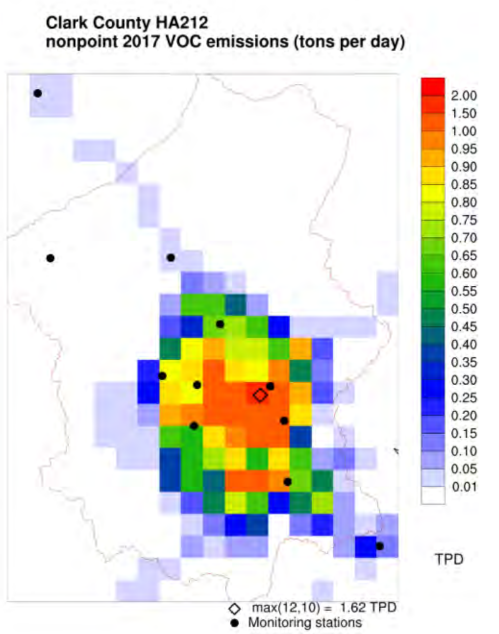
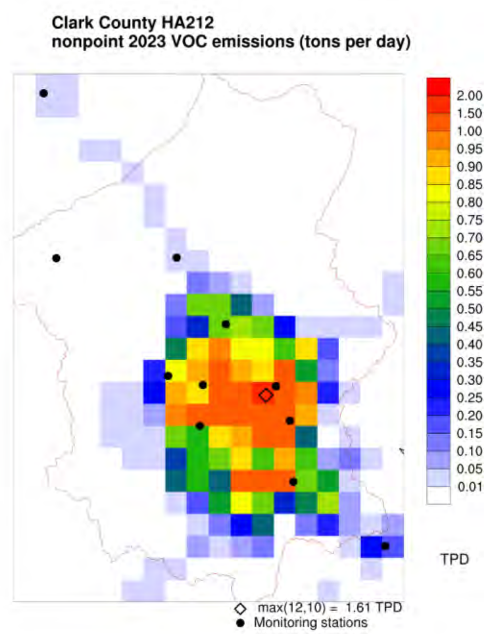
<tr><td>Nonpoint</td><td>
</td><td>
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Figure 10-2 July weekday average VOC emissions for nonroad (top row) and nonpoint (bottom row) sectors presented for the years 2017 (left column) and 2023 (right column).

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Appendix A Clark County Nonattainment Area Nonpoint and Nonroad (Including Locomotive) Emissions by SCC

Appendix A Clark County Nonattainment Area Nonpoint and Nonroad (Including Locomotive) Emissions by SCC

Table A1. HA 212 ozone season weekday nonpoint (including locomotives) emissions by SCC.

SCC	SCC Description	2017 (TPD)		2023 (TPD)	
		NOX	VOC	NOX	VOC
2102002000	Stationary Source Fuel Combustion; Industrial; Bituminous/Subbituminous Coal; Total: All Boiler Types	0.2112	0.0010	0.9570	0.0097
2102004001	Stationary Source Fuel Combustion; Industrial; Distillate Oil; All Boiler Types	0.1089	0.0011	-	-
2102004002	Stationary Source Fuel Combustion; Industrial; Distillate Oil; All IC Engine Types	2.1933	0.1525	1.4665	-
2102006000	Stationary Source Fuel Combustion; Industrial; Natural Gas; Total: Boilers and IC Engines	0.9840	0.0541	-	-
2102007000	Stationary Source Fuel Combustion; Industrial; Liquified Petroleum Gas (LPG); Total: All Boiler Types	0.0656	0.0024	0.0153	0.0004
2102008000	Stationary Source Fuel Combustion; Industrial; Wood; Total: All Boiler Types	0.0229	0.0018	0.0225	0.0017
2102011000	Stationary Source Fuel Combustion; Industrial; Kerosene; Total: All Boiler Types	-	-	0.0006	-
2103004001	Stationary Source Fuel Combustion; Commercial/Institutional; Distillate Oil; Boilers	0.0007	<0.0001	-	-
2103004002	Stationary Source Fuel Combustion; Commercial/Institutional; Distillate Oil; IC Engines	0.0011	0.0001	0.2075	0.0034
2103006000	Stationary Source Fuel Combustion; Commercial/Institutional; Natural Gas; Total: Boilers and IC Engines	1.9344	0.1064	0.7137	-
2103007000	Stationary Source Fuel Combustion; Commercial/Institutional; Liquified Petroleum Gas (LPG); Total: All Combustor Types	0.0750	0.0027	0.1038	0.0024
2103008000	Stationary Source Fuel Combustion; Commercial/Institutional; Wood; Total: All Boiler Types	0.0373	0.0029	0.0372	0.0029

SCC	SCC Description	2017 (TPD)		2023 (TPD)	
		NOX	VOC	NOX	VOC
2103011000	Stationary Source Fuel Combustion; Commercial/Institutional; Kerosene; Total: All Combustor Types	0.0005	<0.0001	-	-
2104004000	Stationary Source Fuel Combustion; Residential; Distillate Oil; Total: All Combustor Types	0.0002	<0.0001	0.0001	<0.0001
2104006000	Stationary Source Fuel Combustion; Residential; Natural Gas; Total: All Combustor Types	0.2233	0.0131	0.1936	0.0113
2104007000	Stationary Source Fuel Combustion; Residential; Liquified Petroleum Gas (LPG); Total: All Combustor Types	0.0065	0.0003	0.0046	0.0002
2104008610	Stationary Source Fuel Combustion; Residential; Wood; Hydronic heater: outdoor	0.0002	0.0068	0.0002	0.0070
2104008620	Stationary Source Fuel Combustion; Residential; Wood; Hydronic heater: indoor	0.0001	0.0043	0.0001	0.0044
2104008630	Stationary Source Fuel Combustion; Residential; Wood; Hydronic heater: pellet-fired	<0.0001	<0.0001	<0.0001	<0.0001
2104008700	Stationary Source Fuel Combustion; Residential; Wood; Outdoor wood burning device, NEC (fire-pits, chimneys, etc.)	0.0541	0.3934	0.0599	0.4354
2302002100	Industrial Processes; Food and Kindred Products: SIC 20; Commercial Cooking - Charbroiling; Conveyorized Charbroiling	-	0.0659	-	0.0473
2302002200	Industrial Processes; Food and Kindred Products: SIC 20; Commercial Cooking - Charbroiling; Under-fired Charbroiling	-	0.2243	-	0.1639
2302003000	Industrial Processes; Food and Kindred Products: SIC 20; Commercial Cooking - Frying; Deep Fat Frying	-	0.0472	-	-
2302003100	Industrial Processes; Food and Kindred Products: SIC 20; Commercial Cooking - Frying; Flat Griddle Frying	-	0.0290	-	-
2302003200	Industrial Processes; Food and Kindred Products: SIC 20; Commercial Cooking - Frying; Clamshell Griddle Frying	-	0.0015	-	-
2401001000	Solvent Utilization; Surface Coating; Architectural Coatings; Total: All Solvent Types	-	4.0113	-	4.3800

SCC	SCC Description	2017 (TPD)		2023 (TPD)	
		NOX	VOC	NOX	VOC
2401100000	Solvent Utilization; Surface Coating; Industrial Maintenance Coatings; Total: All Solvent Types	-	2.0712	-	2.2616
2402000000	Solvent Utilization; Paint Strippers; Chemical Strippers; Application, Degradation, and Coating Removal Steps: Other Not Listed	-	3.4060	-	3.7191
2420000000	Solvent Utilization; Dry Cleaning; All Processes; Total: All Solvent Types	-	0.0649	-	0.0649
2425000000	Solvent Utilization; Graphic Arts; All Processes; Total: All Solvent Types	-	2.3266	-	2.5404
2460100000	Solvent Utilization; Miscellaneous Non-industrial: Consumer and Commercial; All Personal Care Products; Total: All Solvent Types	-	0.1280	-	0.1398
2460110000	Solvent Utilization; Miscellaneous Non-industrial: Consumer and Commercial; Personal Care Products: Hair Care Products; Total: All Solvent Types	-	10.0100	-	10.9300
2460190000	Solvent Utilization; Miscellaneous Non-industrial: Consumer and Commercial; Personal Care Products: Miscellaneous Personal Care Products; Total: All Solvent Types	-	0.2898	-	0.3164
2460200000	Solvent Utilization; Miscellaneous Non-industrial: Consumer and Commercial; All Household Products; Total: All Solvent Types	-	1.1191	-	1.2219
2460290000	Solvent Utilization; Miscellaneous Non-industrial: Consumer and Commercial; Household Products: Miscellaneous Household Products; Total: All Solvent Types	-	9.8108	-	10.7130
2460500000	Solvent Utilization; Miscellaneous Non-industrial: Consumer and Commercial; All Coatings and Related Products; Total: All Solvent Types	-	1.2867	-	1.4050
2460600000	Solvent Utilization; Miscellaneous Non-industrial: Consumer and Commercial; All Adhesives and Sealants; Total: All Solvent Types	-	4.2773	-	4.6704

SCC	SCC Description	2017 (TPD)		2023 (TPD)	
		NOX	VOC	NOX	VOC
2460900000	Solvent Utilization; Miscellaneous Non-industrial: Consumer and Commercial; Miscellaneous Products (Not Otherwise Covered); Total: All Solvent Types	-	0.1076	-	0.1175
2461021000	Solvent Utilization; Miscellaneous Non-industrial: Commercial; Cutback Asphalt; Total: All Solvent Types	-	0.7767	-	0.7767
2461022000	Solvent Utilization; Miscellaneous Non-industrial: Commercial; Emulsified Asphalt; Total: All Solvent Types	-	3.1428	-	3.1428
2461800000	Solvent Utilization; Miscellaneous Non-industrial: Commercial; Pesticide Application: All Processes; Total: All Solvent Types	-	0.4672	-	0.5101
2461850000	Solvent Utilization; Miscellaneous Non-industrial: Commercial; Pesticide Application: Agricultural; All Processes	-	0.0001	-	0.0001
2501011011	Storage and Transport; Petroleum and Petroleum Product Storage; Residential Portable Gas Cans; Permeation	-	0.2020	-	0.2240
2501011012	Storage and Transport; Petroleum and Petroleum Product Storage; Residential Portable Gas Cans; Evaporation (includes Diurnal losses)	-	0.2267	-	0.2513
2501011013	Storage and Transport; Petroleum and Petroleum Product Storage; Residential Portable Gas Cans; Spillage During Transport	-	0.2808	-	0.3114
2501011014	Storage and Transport; Petroleum and Petroleum Product Storage; Residential Portable Gas Cans; Refilling at the Pump - Vapor Displacement	-	0.0577	-	0.0639
2501011015	Storage and Transport; Petroleum and Petroleum Product Storage; Residential Portable Gas Cans; Refilling at the Pump - Spillage	-	0.0083	-	0.0092
2501012011	Storage and Transport; Petroleum and Petroleum Product Storage; Commercial Portable Gas Cans; Permeation	-	0.0097	-	0.0108
2501012012	Storage and Transport; Petroleum and Petroleum Product Storage; Commercial Portable Gas Cans; Evaporation (includes Diurnal losses)	-	0.0080	-	0.0088

SCC	SCC Description	2017 (TPD)		2023 (TPD)	
		NOX	VOC	NOX	VOC
2501012013	Storage and Transport; Petroleum and Petroleum Product Storage; Commercial Portable Gas Cans; Spillage During Transport	-	0.5030	-	0.5578
2501012014	Storage and Transport; Petroleum and Petroleum Product Storage; Commercial Portable Gas Cans; Refilling at the Pump - Vapor Displacement	-	0.2181	-	0.2419
2501012015	Storage and Transport; Petroleum and Petroleum Product Storage; Commercial Portable Gas Cans; Refilling at the Pump - Spillage	-	0.0210	-	0.0233
2501050120	Storage and Transport; Petroleum and Petroleum Product Storage; Bulk Terminals: All Evaporative Losses; Gasoline	-	1.2891	-	1.1602
2501055120	Storage and Transport; Petroleum and Petroleum Product Storage; Bulk Plants: All Evaporative Losses; Gasoline	-	0.0003	-	0.0002
2501060051	Storage and Transport; Petroleum and Petroleum Product Storage; Gasoline Service Stations; Stage 1: Submerged Filling	-	5.5886	-	4.8385
2501060053	Storage and Transport; Petroleum and Petroleum Product Storage; Gasoline Service Stations; Stage 1: Balanced Submerged Filling	-	0.2157	-	0.1867
2501060201	Storage and Transport; Petroleum and Petroleum Product Storage; Gasoline Service Stations; Underground Tank: Breathing and Emptying	-	1.0519	-	0.9107
2501080050	Storage and Transport; Petroleum and Petroleum Product Storage; Airports : Aviation Gasoline; Stage 1: Total	-	0.3451	-	0.3320
2501080100	Storage and Transport; Petroleum and Petroleum Product Storage; Airports : Aviation Gasoline; Stage 2: Total	-	0.0004	-	0.0004
2505030120	Storage and Transport; Petroleum and Petroleum Product Transport; Truck; Gasoline	-	0.0706	-	0.0520
2505040120	Storage and Transport; Petroleum and Petroleum Product Transport; Pipeline; Gasoline	-	0.1018	-	0.0440
2610000500	Waste Disposal, Treatment, and Recovery; Open Burning; All Categories; Land Clearing Debris (use 28-10-005-000 for Logging Debris Burning)	0.1672	0.4723	0.1672	0.4723

SCC	SCC Description	2017 (TPD)		2023 (TPD)	
		NOX	VOC	NOX	VOC
2610030000	Waste Disposal, Treatment, and Recovery; Open Burning; Residential; Household Waste (use 26-10-000-xxx for Yard Wastes)	0.0188	0.0196	0.0188	0.0196
2630020000	Waste Disposal, Treatment, and Recovery; Wastewater Treatment; Public Owned; Total Processed	-	0.0757	-	0.0839
2680003000	Waste Disposal, Treatment, and Recovery; Composting; 100% Green Waste (e.g., residential or municipal yard wastes); All Processes	-	0.7757	-	0.7757
2805002000	Miscellaneous Area Sources; Agriculture Production - Livestock; Beef cattle production composite; Not Elsewhere Classified	-	0.0019	-	0.0019
2805007100	Miscellaneous Area Sources; Agriculture Production - Livestock; Poultry Waste; Poultry Production - Layers with Dry Manure Management Systems: Confinement	-	<0.0001	-	<0.0001
2805009100	Miscellaneous Area Sources; Agriculture Production - Livestock; Poultry production - broilers; Confinement	-	<0.0001	-	<0.0001
2805010100	Miscellaneous Area Sources; Agriculture Production - Livestock; Poultry production - turkeys; Confinement	-	<0.0001	-	<0.0001
2805018000	Miscellaneous Area Sources; Agriculture Production - Livestock; Dairy cattle composite; Not Elsewhere Classified	-	<0.0001	-	<0.0001
2805025000	Miscellaneous Area Sources; Agriculture Production - Livestock; Swine production composite; Not Elsewhere Classified (see also 28-05-039, -047, -053)	-	<0.0001	-	<0.0001
2805035000	Miscellaneous Area Sources; Agriculture Production - Livestock; Horses and Ponies Waste Emissions; Not Elsewhere Classified	-	0.0003	-	0.0003
2805040000	Miscellaneous Area Sources; Agriculture Production - Livestock; Sheep and Lambs Waste Emissions; Total	-	<0.0001	-	<0.0001
2805045000	Miscellaneous Area Sources; Agriculture Production - Livestock; Goats Waste Emissions; Not Elsewhere Classified	-	<0.0001	-	<0.0001

SCC	SCC Description	2017 (TPD)		2023 (TPD)	
		NOX	VOC	NOX	VOC
2810025000	Miscellaneous Area Sources; Other Combustion; Residential Grilling (see 23-02-002-xxx for Commercial); Total	0.0362	0.0960	0.0402	0.1065
2810060100	Miscellaneous Area Sources; Other Combustion; Cremation; Humans	0.0048	0.0004	0.0053	0.0004
2810060200	Miscellaneous Area Sources; Other Combustion; Cremation; Animals	<0.0001	<0.0001	<0.0001	<0.0001
2285002006	Mobile Sources; Railroad Equipment; Diesel; Line Haul Locomotives: Class I Operations	0.7936	0.0366	0.6543	0.0282
2285002007	Mobile Sources; Railroad Equipment; Diesel; Line Haul Locomotives: Class II / III Operations	0.0046	0.0002	0.0047	0.0002
Totals		6.9445	56.0844	4.6731	58.3158

Table A2. HA 212 ozone season weekday nonroad emissions by SCC.

SCC	SCC Description	2017 (TPD)		2023 (TPD)	
		NOX	VOC	NOX	VOC
2260001022	Mobile Sources; Off-highway Vehicle Gasoline; Recreational Equipment; 2-Stroke Other Recreational Equip.	0.0057	0.4635	0.0065	0.3759
2260001060	Mobile Sources; Off-highway Vehicle Gasoline; Recreational Equipment; 2-Stroke Specialty Vehicles/Carts	0.0047	0.0271	0.0045	0.0303
2260002022	Mobile Sources; Off-highway Vehicle Gasoline; Construction Equipment; 2-Stroke Construction Equipment	0.0490	1.9073	0.0561	2.2003
2260003022	Mobile Sources; Off-highway Vehicle Gasoline; Industrial Equipment; 2-Stroke Industrial Equipment	<0.0001	0.0006	<0.0001	0.0007
2260004020	Mobile Sources; Off-highway Vehicle Gasoline; Lawn and Garden Equipment; 2-Stroke Chain Saws < 6 HP (Residential)	0.0049	0.1831	0.0052	0.1947
2260004021	Mobile Sources; Off-highway Vehicle Gasoline; Lawn and Garden Equipment; 2-Stroke Chain Saws < 6 HP (Commercial)	0.0525	2.3689	0.0557	2.5128
2260004022	Mobile Sources; Off-highway Vehicle Gasoline; Lawn and Garden Equipment; 2-Stroke Mowers, Tractors, Turf Eqt (Commercial)	<0.0001	0.0006	<0.0001	0.0006
2260004033	Mobile Sources; Off-highway Vehicle Gasoline; Lawn and Garden Equipment; 2-Stroke Lawn & Garden Eqt (Residential)	0.0185	0.5695	0.0196	0.6445
2260004044	Mobile Sources; Off-highway Vehicle Gasoline; Lawn and Garden Equipment; 2-Stroke Lawn & Garden Eqt (Commercial)	0.1494	3.9788	0.1584	4.2275
2260005022	Mobile Sources; Off-highway Vehicle Gasoline; Agricultural Equipment; 2-Stroke Agriculture Equipment	<0.0001	<0.0001	<0.0001	<0.0001
2260006022	Mobile Sources; Off-highway Vehicle Gasoline; Commercial Equipment; 2-Stroke Commercial Equipment	0.0039	0.1111	0.0046	0.1313
2265001022	Mobile Sources; Off-highway Vehicle Gasoline; Recreational Equipment; 4-Stroke Other Recreational Equip.	0.0170	0.2305	0.0169	0.2398
2265001050	Mobile Sources; Off-highway Vehicle Gasoline; Recreational Equipment; 4-Stroke Golf Carts	0.0292	0.1050	0.0315	0.1141
2265001060	Mobile Sources; Off-highway Vehicle Gasoline; Recreational Equipment; 4-Stroke Specialty Vehicles/Carts	0.0062	0.0287	0.0049	0.0236
2265002022	Mobile Sources; Off-highway Vehicle Gasoline; Construction Equipment; 4-Stroke Construction Equipment	0.2899	1.1038	0.2854	1.2599
2265003022	Mobile Sources; Off-highway Vehicle Gasoline; Industrial Equipment; 4-Stroke Industrial Equipment	0.0147	0.0237	0.0155	0.0283

SCC	SCC Description	2017 (TPD)		2023 (TPD)	
		NOX	VOC	NOX	VOC
2265003060	Mobile Sources; Off-highway Vehicle Gasoline; Industrial Equipment; 4-Stroke AC\Refrigeration	0.0002	0.0008	0.0002	0.0011
2265004022	Mobile Sources; Off-highway Vehicle Gasoline; Lawn and Garden Equipment; 4-Stroke Mowers, Tractors, Turf Eqt (Commercial)	0.8958	3.3743	0.9575	3.6501
2265004033	Mobile Sources; Off-highway Vehicle Gasoline; Lawn and Garden Equipment; 4-Stroke Lawn & Garden Eqt (Residential)	0.2817	2.5117	0.2688	2.6700
2265004044	Mobile Sources; Off-highway Vehicle Gasoline; Lawn and Garden Equipment; 4-Stroke Lawn & Garden Eqt (Commercial)	0.4767	2.8519	0.4734	2.9588
2265005022	Mobile Sources; Off-highway Vehicle Gasoline; Agricultural Equipment; 4-Stroke Agriculture Equipment	<0.0001	<0.0001	<0.0001	<0.0001
2265006022	Mobile Sources; Off-highway Vehicle Gasoline; Commercial Equipment; 4-Stroke Commercial Equipment	0.1635	0.9646	0.1754	1.1718
2267001060	Mobile Sources; Off-highway Vehicle LPG; Recreational Equipment; LPG Specialty Vehicles/Carts	0.0014	0.0003	0.0010	0.0002
2267002022	Mobile Sources; Off-highway Vehicle LPG; Construction Equipment; LPG Construction Equipment	0.0846	0.0169	0.0526	0.0085
2267003022	Mobile Sources; Off-highway Vehicle LPG; Industrial Equipment; LPG Industrial Equipment	0.1184	0.0179	0.1198	0.0142
2267004044	Mobile Sources; Off-highway Vehicle LPG; Lawn and Garden Equipment; LPG Lawn & Garden Eqt (Commercial)	0.0160	0.0024	0.0138	0.0016
2267005022	Mobile Sources; Off-highway Vehicle LPG; Agricultural Equipment; LPG Agriculture Equipment	<0.0001	<0.0001	<0.0001	<0.0001
2267006022	Mobile Sources; Off-highway Vehicle LPG; Commercial Equipment; LPG Commercial Equipment	0.0524	0.0086	0.0349	0.0053
2268002022	Mobile Sources; Off-highway Vehicle CNG; Construction Equipment; CNG Construction Equipment	0.0005	0.0004	0.0002	0.0001
2268003022	Mobile Sources; Off-highway Vehicle CNG; Industrial Equipment; CNG Industrial Equipment	0.0092	0.0049	0.0095	0.0041
2268003060	Mobile Sources; Off-highway Vehicle CNG; Industrial Equipment; CNG AC\Refrigeration	0.0001	<0.0001	0.0001	<0.0001
2268005022	Mobile Sources; Off-highway Vehicle CNG; Agricultural Equipment; CNG Agriculture Equipment	<0.0001	<0.0001	<0.0001	<0.0001

SCC	SCC Description	2017 (TPD)		2023 (TPD)	
		NOX	VOC	NOX	VOC
2268006022	Mobile Sources; Off-highway Vehicle CNG; Commercial Equipment; CNG Commercial Equipment	0.0232	0.0128	0.0195	0.0103
2270001060	Mobile Sources; Off-highway Vehicle Diesel; Recreational Equipment; Specialty Vehicles/Carts	0.0157	0.0036	0.0121	0.0023
2270002022	Mobile Sources; Off-highway Vehicle Diesel; Construction Equipment; Diesel Construction Equipment	31.6988	2.9074	18.1476	1.5308
2270003022	Mobile Sources; Off-highway Vehicle Diesel; Industrial Equipment; Diesel Industrial Equipment	0.1188	0.0079	0.0735	0.0034
2270003060	Mobile Sources; Off-highway Vehicle Diesel; Industrial Equipment; AC\Refrigeration	0.3474	0.0202	0.3803	0.0131
2270004022	Mobile Sources; Off-highway Vehicle Diesel; Lawn and Garden Equipment; Diesel Mowers, Tractors, Turf Eqt (Commercial)	0.1441	0.0137	0.1258	0.0103
2270004044	Mobile Sources; Off-highway Vehicle Diesel; Lawn and Garden Equipment; Diesel Lawn & Garden Eqt (Commercial)	1.3020	0.1214	0.9766	0.0774
2270005022	Mobile Sources; Off-highway Vehicle Diesel; Agricultural Equipment; Diesel Agriculture Equipment	0.0005	<0.0001	0.0003	<0.0001
2270006022	Mobile Sources; Off-highway Vehicle Diesel; Commercial Equipment; Diesel Commercial Equipment	0.5754	0.0664	0.4625	0.0427
2282005022	Mobile Sources; Pleasure Craft; Gasoline; 2-Stroke Pleasure Craft	0.0022	0.0157	0.0023	0.0086
2282010005	Mobile Sources; Pleasure Craft; Gasoline 4-Stroke; Inboard/Sterndrive	0.0015	0.0024	0.0010	0.0019
2282020022	Mobile Sources; Pleasure Craft; Diesel; Diesel Pleasure Craft	0.0014	0.0001	0.0013	0.0001
2285002015	Mobile Sources; Railroad Equipment; Diesel; Railway Maintenance	0.0059	0.0010	0.0041	0.0006
2285004015	Mobile Sources; Railroad Equipment; Gasoline, 4-Stroke; Railway Maintenance	0.0001	0.0004	0.0001	0.0005
2285006015	Mobile Sources; Railroad Equipment; LPG; Railway Maintenance	<0.0001	<0.0001	<0.0001	<0.0001
Totals		36.9831	24.0299	22.9790	24.1721

Appendix B Clark County Nonattainment Area Unit-level Point Source Emissions

Appendix B Clark County Nonattainment Area Unit-level Point Source Emissions

Table B1. HA 212 unit-level point source NOx emissions for 2017 and 2023.

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
Certain Teed Gypsum	Generator	4	4-L4	20200401	27	0.36	0.001	0.001	0.3620	0.0010	0.0011	0.0000	2016 v.1
Certain Teed Gypsum	Generator	4	B8	20200401	27	0.92	0.003	0.003	0.9240	0.0025	0.0027	0.0000	2016 v.1
Certain Teed Gypsum	Continuous Calciner	4	4-G1	30501511	25	5.02	0.014	0.014	5.3814	0.0147	0.0147	0.0120	2016 v.1
Certain Teed Gypsum	Impact Mill	4	4-E11	30501513	25	3.82	0.010	0.010	4.0950	0.0112	0.0112	0.0120	2016 v.1
Certain Teed Gypsum	Dryer	4	4-J3	30501520	25	1.31	0.004	0.004	1.4043	0.0038	0.0038	0.0120	2016 v.1
NV Energy (Clark Station)	Turbine	7	4	20100201	25	8.33	0.023	0.023	8.3450	0.0229	0.0229	0.0004	2016 v.1
NV Energy (Clark Station)	Turbine	7	5	20100201	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	6	20100201	25	2.80	0.008	0.008	3.0705	0.0084	0.0084	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	7	20100201	25	0.51	0.001	0.001	0.5593	0.0015	0.0015	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	8	20100201	25	0.75	0.002	0.002	0.8225	0.0023	0.0023	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	27	20100201	25	2.43	0.007	0.007	2.6647	0.0073	0.0073	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	28	20100201	25	3.32	0.009	0.009	3.6407	0.0100	0.0100	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	29	20100201	25	5.63	0.015	0.015	6.1739	0.0169	0.0169	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	30	20100201	25	3.90	0.011	0.011	4.2767	0.0117	0.0117	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	31	20100201	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	32	20100201	25	3.13	0.009	0.009	3.4324	0.0094	0.0094	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	33	20100201	25	3.05	0.008	0.008	3.3446	0.0092	0.0092	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	34	20100201	25	5.14	0.014	0.014	5.6365	0.0154	0.0154	0.0161	2016 v.1

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
NV Energy (Clark Station)	Turbine	7	35	20100201	25	0.70	0.002	0.002	0.7676	0.0021	0.0021	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	36	20100201	25	2.02	0.006	0.006	2.2151	0.0061	0.0061	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	37	20100201	25	0.07	0.000	0.000	0.0768	0.0002	0.0002	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	38	20100201	25	4.96	0.014	0.014	5.4391	0.0149	0.0149	0.0161	2016 v.1
NV Energy (Clark Station)	Generator	7	21	20200102	25	0.45	0.001	0.001	0.4935	0.0014	0.0014	0.0161	2016 v.1
NV Energy (Clark Station)	Generator	7	22	20200102	25	1.76	0.005	0.005	1.9300	0.0053	0.0053	0.0161	2016 v.1
NV Energy (Clark Station)	Generator	7	45	20200102	25	19.90	0.055	0.055	21.8223	0.0598	0.0598	0.0161	2016 v.1
NV Energy (Clark Station)	Generator	7	46	20200102	25	2.85	0.008	0.008	3.1253	0.0086	0.0086	0.0161	2016 v.1
Olin Chlor Alkali Products	Generator	9	1	20200102	25	7.53	0.021	0.021	8.2574	0.0226	0.0226	0.0161	2016 v.1
Viawest Lone Mountain Data Center	Generator	12	2	20300101	25	4.52	0.012	0.012	4.9566	0.0136	0.0136	0.0161	2016 v.1
Wells Cargo	Asphalt Oil Heater	12	1	30500206	25	0.90	0.002	0.002	0.9869	0.0027	0.0027	0.0161	2016 v.1
Kinder Morgan	Diesel Pump	13	D02	20200102	25	4.18	0.011	0.011	4.5838	0.0126	0.0126	0.0161	2016 v.1
Kinder Morgan	Flare Processing	13	B10	30600904	25	1.26	0.003	0.003	1.3817	0.0038	0.0038	0.0161	2016 v.1
Kinder Morgan	Thermal Oxidizer	13	SR04	50410312	25	0.89	0.002	0.002	0.9760	0.0027	0.0027	0.0161	2016 v.1
Titanium Metals Corp.	Steam Generator	19	B09	10200602	25	1.42	0.004	0.004	1.5572	0.0043	0.0043	0.0161	2016 v.1
Titanium Metals Corp.	CO Burner/Boiler	19	B06	10201402	25	0.67	0.002	0.002	0.7347	0.0020	0.0020	0.0161	2016 v.1
Titanium Metals Corp.	Hot Oil Heater	19	C05	30301201	25	17.45	0.048	0.048	19.1357	0.0524	0.0524	0.0161	2016 v.1
Titanium Metals Corp.	Generator	19	E03	30301202	25	2.13	0.006	0.006	2.3358	0.0064	0.0064	0.0161	2016 v.1
Titanium Metals Corp.	Fugitives	19	A01	30301299	25	0.10	0.000	0.000	0.1097	0.0003	0.0003	0.0161	2016 v.1

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
Titanium Metals Corp.	Thermal Oxidizer	19	B10	30301299	25	40.26	0.110	0.110	44.1491	0.1210	0.1210	0.0161	2016 v.1
Northwind Alladin	Boiler	26	1	10300603	25	7.81	0.021	0.021	8.5644	0.0235	0.0235	0.0161	2016 v.1
Circus Circus Hotel and Casino	Boiler	47	1	10300603	25	0.83	0.002	0.002	0.9102	0.0025	0.0025	0.0161	2016 v.1
CCWRD Flamingo Center	Boiler	54	1	10300603	25	2.07	0.006	0.006	2.2700	0.0062	0.0062	0.0161	2016 v.1
BKEP Materials	Boiler	67	1	10300603	25	7.45	0.020	0.020	8.1697	0.0224	0.0224	0.0161	2016 v.1
Las Vegas Paving - Blue Diamond	Drum Mixer	70	B12	30500257	25	8.84	0.024	0.024	9.6939	0.0266	0.0266	0.0161	2016 v.1
Golden Nugget Hotel and Casino	Boiler	81	1	10300603	25	2.94	0.008	0.008	3.2240	0.0088	0.0088	0.0161	2016 v.1
Horseshoe Club	Boiler	85	1	10300603	25	0.91	0.002	0.002	0.9979	0.0027	0.0027	0.0161	2016 v.1
Tronox	Boiler	95	A10	10300602	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0161	2016 v.1
Tronox	Boiler	95	A15	10300602	25	0.06	0.000	0.000	0.0658	0.0002	0.0002	0.0161	2016 v.1
Treasure Island	Boiler	95	A01	10300603	25	22.77	0.062	0.062	24.9696	0.0684	0.0684	0.0161	2016 v.1
Tronox	Generator	95	A02	20300101	25	4.24	0.012	0.012	4.6496	0.0127	0.0127	0.0161	2016 v.1
Tronox	Generator	95	A03	20300101	25	4.12	0.011	0.011	4.5180	0.0124	0.0124	0.0161	2016 v.1
Tronox	Generator	95	A04	20300101	25	6.00	0.016	0.016	6.5796	0.0180	0.0180	0.0161	2016 v.1
Tronox	Generator	95	A07	20300101	25	1.61	0.004	0.004	1.7655	0.0048	0.0048	0.0161	2016 v.1
Tronox	Chem. Manufacturing	95	A05	30107002	25	1.58	0.004	0.004	1.7326	0.0047	0.0047	0.0161	2016 v.1
Westgate Las Vegas	Generator	101	B	20100102	25	2.16	0.006	0.006	2.3687	0.0065	0.0065	0.0161	2016 v.1
West Rock	Printing Press	101	G	40500501	25	2.79	0.008	0.008	3.0595	0.0084	0.0084	0.0161	2016 v.1
Las Vegas Paving - 5th Street	Fire Pump	104	H01	20200102	25	4.34	0.012	0.012	4.7592	0.0130	0.0130	0.0161	2016 v.1
Las Vegas Paving - 5th Street	Drum Mixer	104	E01	30500205	25	1.27	0.003	0.003	1.3927	0.0038	0.0038	0.0161	2016 v.1
Las Vegas Paving - 5th Street	Oil Heater	104	E02	30500206	25	5.36	0.015	0.015	5.8778	0.0161	0.0161	0.0161	2016 v.1

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
Las Vegas Paving - 5th Street	Drum Dryer	104	E03	39001089	25	13.75	0.038	0.038	15.0783	0.0413	0.0413	0.0161	2016 v.1
Las Vegas Paving - Lone Mountain	Generator	105	C	20200102	25	3.10	0.008	0.008	3.3995	0.0093	0.0093	0.0161	2016 v.1
Las Vegas Paving - Lone Mountain	Drum Dryer	105	B012	30500205	25	33.23	0.091	0.091	33.2300	0.0910	0.0910	0.0000	2016 v.1
Las Vegas Paving - Lone Mountain	Oil Heater	105	B011	30500209	25	4.01	0.011	0.011	4.0100	0.0110	0.0110	0.0000	2016 v.1
McCarran International Airport	Boiler	108	A	10300602	25	0.38	0.001	0.001	0.3800	0.0010	0.0010	0.0000	2016 v.1
McCarran International Airport	Generator	108	E	20200102	25	0.10	0.000	0.000	0.1000	0.0003	0.0003	0.0000	2016 v.1
Nellis AFB	Nat gas boilers	114	RB-C	10300602	51	0.04	0.000	0.000	0.0400	0.0001	0.0002	0.0000	2016 v.1
Nellis AFB	Internal Combustion	114	G	20300301	51	0.08	0.000	0.000	0.0800	0.0002	0.0004	0.0000	2016 v.1
Nellis AFB	Hush House	114	N	20400110	25	0.33	0.001	0.001	0.3300	0.0009	0.0009	0.0000	2016 v.1
Nellis AFB	Drum Mixer	114	A047	30500205	25	0.03	0.000	0.000	0.0300	0.0001	0.0001	0.0000	2016 v.1
SLS Las Vegas	Boiler	133	A	10300602	25	0.06	0.000	0.000	0.0600	0.0002	0.0002	0.0000	2016 v.1
SLS Las Vegas	Generator	133	B	20300101	27	0.06	0.000	0.000	0.0610	0.0002	0.0002	0.0000	2016 v.1
University Medical Center	Boiler	142	B	10300603	27	0.08	0.000	0.000	0.0790	0.0002	0.0002	0.0000	2016 v.1
Univeral Urethane	Spray painting booths	142	A	40202201	25	0.27	0.001	0.001	0.2700	0.0007	0.0007	0.0000	2016 v.1
Las Vegas Paving	Drum Mixer	186	B013	30500205	25	4.90	0.013	0.013	4.9000	0.0134	0.0134	0.0000	2016 v.1
Las Vegas Paving	Oil Heater	186	B023	30500208	51	5.33	0.015	0.030	6.4717	0.0177	0.0362	0.0357	2016 v.1
Caesars Consolidated	Boiler	257	1	10300603	51	2.00	0.005	0.011	2.4284	0.0067	0.0136	0.0357	2016 v.1
Mirage/Treasure Island	Boiler	282	1	10300603	51	2.75	0.008	0.015	3.3391	0.0091	0.0187	0.0357	2016 v.1
Brady Linen Services	Dryer	322	1	30504033	51	2.72	0.007	0.015	3.3026	0.0090	0.0185	0.0357	2016 v.1
Catalina Plastic and Coating	Plastics	323	1	40201399	51	2.86	0.008	0.016	3.4726	0.0095	0.0194	0.0357	2016 v.1

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
Las Vegas Cogeneration	Generator	329	10	20100102	25	6.21	0.017	0.017	7.5402	0.0207	0.0207	0.0357	2016 v.1
Las Vegas Cogeneration	Generator	329	11	20100102	37	6.73	0.018	0.027	7.0583	0.0193	0.0286	0.0081	ERTAC
Las Vegas Cogeneration	Turbine	329	1	20100201	37	5.10	0.014	0.021	5.2522	0.0144	0.0213	0.0050	ERTAC
Las Vegas Cogeneration	Turbine	329	3	20100201	37	4.06	0.011	0.016	4.2682	0.0117	0.0173	0.0085	ERTAC
Las Vegas Cogeneration	Turbine	329	4	20100201	27	8.70	0.024	0.026	10.5635	0.0289	0.0313	0.0357	2016 v.1
Las Vegas Cogeneration	Turbine	329	5	20100201	27	10.20	0.028	0.030	12.3848	0.0339	0.0366	0.0357	2016 v.1 2023; IPM 2016-2030
Las Vegas Cogeneration	Turbine	329	6	20100201	27	10.40	0.028	0.031	12.6277	0.0346	0.0374	0.0357	2016 v.1 2023; IPM 2016-2030
Boral Roofing	Curing Tunnel	346	B18	30500850	27	7.90	0.022	0.023	9.5922	0.0263	0.0284	0.0357	2016 v.1 2023; IPM 2016-2030
Aggregate Industries	Boiler	372	6	10300602	27	11.20	0.031	0.033	13.5990	0.0373	0.0402	0.0357	2016 v.1 2023; IPM 2016-2030
Aggregate Industries	Boiler	372	10	10300602	27	2.95	0.008	0.009	3.4417	0.0094	0.0102	0.027777778	ERTAC
Aggregate Industries	Generator	372	1	20100102	27	4.68	0.013	0.014	4.6800	0.0128	0.0138	0	ERTAC
Aggregate Industries	Generator	372	9	20100102	27	3.24	0.009	0.010	3.6626	0.0100	0.0108	0.02173913	ERTAC
Aggregate Industries	Mineral Products	372	2	30500208	27	5.33	0.015	0.016	6.0914	0.0167	0.0180	0.023809524	ERTAC
Aggregate Industries	Mineral Products	372	5	30500208	27	3.39	0.009	0.010	3.6848	0.0101	0.0109	0.014492754	ERTAC
Aggregate Industries	Mineral Products	372	3	30500242	27	3.70	0.010	0.011	4.2842	0.0117	0.0127	0.026315789	ERTAC
Saguaro Power Company	Boiler	393	5	10100601	27	3.22	0.009	0.010	3.4152	0.0094	0.0101	0.01010101	ERTAC
Saguaro Power Company	Boiler	393	6	10100602	27	4.25	0.012	0.013	4.7652	0.0131	0.0141	0.02020202	ERTAC

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
Saguaro Power Company	Starter	393	3	20100102	27	3.13	0.009	0.009	3.4022	0.0093	0.0101	0.014492754	ERTAC
Saguaro Power Company	Starter	393	4	20100102	27	4.19	0.011	0.012	4.9187	0.0135	0.0146	0.028985507	ERTAC
Saguaro Power Company	Turbine	393	1	20100201	27	3.08	0.008	0.009	3.4424	0.0094	0.0102	0.019607843	ERTAC
Saguaro Power Company	Turbine	393	2	20100201	27	3.25	0.009	0.010	3.7143	0.0102	0.0110	0.023809524	ERTAC
City of Las Vegas WPCF	Generator	402	2	20200102	27	51.92	0.142	0.154	63.0461	0.1727	0.1865	0.0357	2016 v.1*
City of Las Vegas WPCF	Generator	402	3	20200202	27	49.45	0.135	0.146	60.0470	0.1645	0.1777	0.0357	2016 v.1*
City of Las Vegas WPCF	Waste Flare	402	5	50100789	25	0.02	0.000	0.000	0.0229	0.0001	0.0001	0.0238	2016 v.1
City of Las Vegas WPCF	Blower Engines	402	6	50100799	25	1.01	0.003	0.003	1.1542	0.0032	0.0032	0.0238	2016 v.1
City of Las Vegas WPCF	Boilers	402	7	50100799	25	0.07	0.000	0.000	0.0800	0.0002	0.0002	0.0238	2016 v.1
Nikkiso Cryo	Generator	404	1	20200102	25	7.70	0.021	0.021	8.7996	0.0241	0.0241	0.0238	2016 v.1
Nevada Sun Peak Partnerships	Turbine	423	1	20100201	25	0.06	0.000	0.000	0.0686	0.0002	0.0002	0.0238	2016 v.1
Nevada Sun Peak Partnerships	Turbine	423	2	20100201	25	44.93	0.123	0.123	51.3460	0.1407	0.1407	0.0238	2016 v.1
Nevada Sun Peak Partnerships	Turbine	423	3	20100201	25	4.69	0.013	0.013	5.3597	0.0147	0.0147	0.0238	2016 v.1
Hard Rock Hotel and Casino	Boiler	510	A	10300603	25	8.90	0.024	0.024	10.1709	0.0279	0.0279	0.0238	2016 v.1
Hard Rock Hotel and Casino	Generator	510	B	20300101	27	0.01	0.000	0.000	0.0114	0.0000	0.0000	0.0238	2016 v.1
Texas Station Casino	Boiler	531	A	10300603	27	0.01	0.000	0.000	0.0114	0.0000	0.0000	0.0238	2016 v.1
Texas Station Casino	Generator	531	B	20300101	27	0.01	0.000	0.000	0.0114	0.0000	0.0000	0.0238	2016 v.1
Citibank The Lakes	Generator	546	A	20300101	27	0.01	0.000	0.000	0.0114	0.0000	0.0000	0.0238	2016 v.1
Rio All Suites Hotel and Casino	Boiler	555	A	10300603	25	0.86	0.002	0.002	0.9828	0.0027	0.0027	0.0238	2016 v.1

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
Rio All Suites Hotel and Casino	Generator	555	C	20300101	25	0.01	0.000	0.000	0.0114	0.0000	0.0000	0.0238	2016 v.1
Kurt Segler Water Reclamation	Generator	558	B	20200102	25	0.10	0.000	0.000	0.0954	0.0003	0.0003	-0.0076	2016 v.1
Kurt Segler Water Reclamation	Waste water treatment	558	B01	50100765	25	1.67	0.005	0.005	1.8403	0.0050	0.0050	0.0170	2016 v.1
Stratosphere Hotel and Casino	Boiler	564	A	10300603	25	0.03	0.000	0.000	0.0331	0.0001	0.0001	0.0170	2016 v.1
Stratosphere Hotel and Casino	Generator	564	B	20300101	25	0.71	0.002	0.002	0.8033	0.0022	0.0022	0.0219	2016 v.1
Aggregate Industries - Gowan	Drum Mixer	587	A08	30500205	25	1.05	0.003	0.003	1.1880	0.0033	0.0033	0.0219	2016 v.1
Aggregate Industries - Gowan	Asphalt Oil Heater	587	E	30500208	25	0.09	0.000	0.000	0.1018	0.0003	0.0003	0.0219	2016 v.1
Aggregate Industries - Gowan	Asphalt Silos	587	A12	30500212	25	73.04	0.200	0.200	82.6375	0.2264	0.2264	0.0219	2016 v.1
Las Vegas Review Journal	Generator	588	D	20300101	25	0.98	0.003	0.003	1.1088	0.0030	0.0030	0.0219	2016 v.1
Las Vegas Review Journal	Parts Washer	588	B	40500417	25	0.47	0.001	0.001	0.5318	0.0015	0.0015	0.0219	2016 v.1
Berry Plastics Corporation	Generator	597	F01	20300101	25	0.52	0.001	0.001	0.5883	0.0016	0.0016	0.0219	2016 v.1
Berry Plastics Corporation	Offset Printing	597	E01	40500802	25	2.05	0.006	0.006	2.3194	0.0064	0.0064	0.0219	2016 v.1
Palace Station Hotel and Casino	Boiler	605	A	10300603	25	0.28	0.001	0.001	0.3168	0.0009	0.0009	0.0219	2016 v.1
Palace Station Hotel and Casino	Generator	605	B	20300101	25	1.09	0.003	0.003	1.2332	0.0034	0.0034	0.0219	2016 v.1
Gold Coast Hotel and Casino	Boiler	606	A	10300603	25	2.47	0.007	0.007	2.7946	0.0077	0.0077	0.0219	2016 v.1
Gold Coast Hotel and Casino	Generator	606	B	20300101	25	0.21	0.001	0.001	0.2376	0.0007	0.0007	0.0219	2016 v.1
Sams Town Hotel and Casino	Boiler	616	A	10300603	25	11.35	0.031	0.031	12.8414	0.0352	0.0352	0.0219	2016 v.1
Sams Town Hotel and Casino	Generator	616	B	20300101	25	0.11	0.000	0.000	0.1245	0.0003	0.0003	0.0219	2016 v.1
Santa Fe Station	Boiler	621	A	10300603	25	1.07	0.003	0.003	1.2106	0.0033	0.0033	0.0219	2016 v.1

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
Santa Fe Station	Generator	621	B	20300101	25	0.45	0.001	0.001	0.5091	0.0014	0.0014	0.0219	2016 v.1
University Medical Center	Generator	634	B	20300101	25	0.81	0.002	0.002	0.9164	0.0025	0.0025	0.0219	2016 v.1
University of Nevada, Las Vegas	Generator	634	A	20300101	25	0.40	0.001	0.001	0.4526	0.0012	0.0012	0.0219	2016 v.1
Orleans Hotel and Casino	Boiler	641	A	10300603	25	1.35	0.004	0.004	1.5274	0.0042	0.0042	0.0219	2016 v.1
Orleans Hotel and Casino	Generator	641	B	20300101	25	0.77	0.002	0.002	0.8712	0.0024	0.0024	0.0219	2016 v.1
University of Nevada, Las Vegas	Boiler	697	C	10300603	25	18.60	0.051	0.051	21.0440	0.0577	0.0577	0.0219	2016 v.1
Venetian Hotel and Casino	Generator	697	B	20300101	25	1.26	0.003	0.003	1.4256	0.0039	0.0039	0.0219	2016 v.1
Venetian Hotel and Casino	Boiler	726	A	10300603	25	0.58	0.002	0.002	0.6562	0.0018	0.0018	0.0219	2016 v.1
Nevada Color Litho	Printing Press	754	A05	40500433	25	0.54	0.001	0.001	0.6110	0.0017	0.0017	0.0219	2016 v.1
JW Marriott Las Vegas	Boiler	755	A	10300603	25	0.38	0.001	0.001	0.4299	0.0012	0.0012	0.0219	2016 v.1
JW Marriott Las Vegas	Generator	755	B	20300101	25	1.73	0.005	0.005	1.9573	0.0054	0.0054	0.0219	2016 v.1
Suncoast Hotel and Casino	Boiler	775	A	10300603	25	0.23	0.001	0.001	0.2602	0.0007	0.0007	0.0219	2016 v.1
Suncoast Hotel and Casino	Generator	775	B	20300101	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0219	2016 v.1
Veterans Administration	Generator	777	A	20300101	25	1.64	0.004	0.004	1.8555	0.0051	0.0051	0.0219	2016 v.1
Cancun Resort	Boiler	788	A	10300603	25	0.03	0.000	0.000	0.0339	0.0001	0.0001	0.0219	2016 v.1
Cancun Resort	Generator	788	B	20300101	25	0.74	0.002	0.002	0.8372	0.0023	0.0023	0.0219	2016 v.1
Clearwater Paper	Boiler	807	A10	10200602	25	0.55	0.002	0.002	0.6223	0.0017	0.0017	0.0219	2016 v.1
Clearwater Paper	Air heaters	807	A08	30790003	25	0.29	0.001	0.001	0.3281	0.0009	0.0009	0.0219	2016 v.1
Clearwater Paper	Paper process fugitives	807	F	30799998	25	0.79	0.002	0.002	0.8938	0.0024	0.0024	0.0219	2016 v.1
MGM Grand/New York New York	Boiler	825	A	10300603	25	1.24	0.003	0.003	1.4029	0.0038	0.0038	0.0219	2016 v.1

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
MGM Grand/New York New York	Turbine	825	E	20100201	25	5.23	0.014	0.014	5.9172	0.0162	0.0162	0.0219	2016 v.1
MGM Grand/New York New York	Generator	825	B	20300101	25	1.06	0.003	0.003	1.1993	0.0033	0.0033	0.0219	2016 v.1
MGM Grand/New York New York	Paint booth	825	C	40201101	25	0.35	0.001	0.001	0.3960	0.0011	0.0011	0.0219	2016 v.1
MGM Grand/New York New York	Tank	825	D	40600401	25	1.83	0.005	0.005	2.0705	0.0057	0.0057	0.0219	2016 v.1
UNEV Pipeline	Generator	859	A	20200102	25	3.34	0.009	0.009	3.7789	0.0104	0.0104	0.0219	2016 v.1
Univeral Urethane	Molding machines	859	B	30800802	25	0.47	0.001	0.001	0.5318	0.0015	0.0015	0.0219	2016 v.1
Sunset Station	Boiler	869	A	10300603	25	0.32	0.001	0.001	0.3620	0.0010	0.0010	0.0219	2016 v.1
Sunset Station	Generator	869	B	20300101	25	0.04	0.000	0.000	0.0453	0.0001	0.0001	0.0219	2016 v.1
Wynn Las Vegas	Boiler	974	A	10300602	25	0.10	0.000	0.000	0.1131	0.0003	0.0003	0.0219	2016 v.1
Wells Cargo Lone Mountain	Engines	1055	A	20300101	25	0.10	0.000	0.000	0.1131	0.0003	0.0003	0.0219	2016 v.1
Republic Services Transfer Station	Boiler	1087	B	10300603	25	0.37	0.001	0.001	0.4186	0.0011	0.0011	0.0219	2016 v.1
Republic Services Transfer Station	Generator	1087	G	20300101	25	2.76	0.008	0.008	3.1227	0.0086	0.0086	0.0219	2016 v.1
Las Vegas Color Graphics	Printing Press	1149	A	40500411	25	2.21	0.006	0.006	2.5004	0.0069	0.0069	0.0219	2016 v.1
St Rose Dominican Siena	Boiler	1500	A	10300603	25	4.09	0.011	0.011	4.6274	0.0127	0.0127	0.0219	2016 v.1
St Rose Dominican Siena	Generator	1500	B	20300101	25	0.96	0.003	0.003	1.0861	0.0030	0.0030	0.0219	2016 v.1
Green Valley Ranch Resort	Boiler	1501	A	10300603	25	2.86	0.008	0.008	3.2358	0.0089	0.0089	0.0219	2016 v.1
Green Valley Ranch Resort	Generator	1501	B	20300101	25	1.11	0.003	0.003	1.2559	0.0034	0.0034	0.0219	2016 v.1
Palms Casino Resort	Boiler	1522	A	10300603	25	0.40	0.001	0.001	0.4526	0.0012	0.0012	0.0219	2016 v.1
Palms Casino Resort	Generator	1522	B	20300101	25	39.42	0.108	0.108	44.5998	0.1222	0.1222	0.0219	2016 v.1
Boulder Station Hotel and Casino	Boiler	1524	A	10300603	25	2.59	0.007	0.007	2.9303	0.0080	0.0080	0.0219	2016 v.1

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
Boulder Station Hotel and Casino	Generator	1524	B	20300101	25	4.77	0.013	0.013	4.8301	0.0132	0.0132	0.0021	2016 v.1
Mountain View Hospital	Boiler	1569	A	10300603	25	5.92	0.016	0.016	6.9110	0.0189	0.0189	0.0279	2016 v.1
Mountain View Hospital	Generator	1569	B	20300101	25	9.18	0.025	0.025	9.8520	0.0270	0.0270	0.0122	2016 v.1
Lasfuel McCarran Tank Farm	Generator	1589	C	20300101	25	1.20	0.003	0.003	1.2000	0.0033	0.0033	0.0000	2016 v.1
Lasfuel McCarran Tank Farm	Thermal Oxidizer	1589	B06	40400153	25	0.06	0.000	0.000	0.0600	0.0002	0.0002	0.0000	default value
Wynn Las Vegas	Generator	1624	A	20100102	25	1.07	0.003	0.003	1.0700	0.0029	0.0029	0.0000	default value
World Market Center	Generator	1624	F	20300101	25	0.01	0.000	0.000	0.0050	0.0000	0.0000	0.0000	2016 v.1
Wynn Las Vegas	Dry Cleaning	1624	R	40100103	25	12.41	0.034	0.034	12.4050	0.0340	0.0340	0.0000	2016 v.1
Wynn Las Vegas	AST	1624	C	40600306	25	0.10	0.000	0.000	0.1000	0.0003	0.0003	0.0000	2016 v.1
North Las Vegas Airport	Generator	9596	C	20100102	25	5.12	0.014	0.014	5.1200	0.0140	0.0140	0.0000	2016 v.1
Henderson Executive Airport	Generator	9603	B	20100102	25	1.63	0.004	0.004	1.6300	0.0045	0.0045	0.0000	2016 v.1
Brady Linen Services	Boiler	10201	B	10200602	25	4.15	0.011	0.011	4.1500	0.0114	0.0114	0.0000	2016 v.1
Brady Linen Services	Dryer	10201	D	41000130	25	5.71	0.016	0.016	5.7100	0.0156	0.0156	0.0000	2016 v.1
Republic Services (Sunrise)	Flare	15033	1	50300601	25	0.23	0.001	0.001	0.2300	0.0006	0.0006	0.0000	2016 v.1
CPP Acquisition	Dryer	15193	D	40500101	25	0.59	0.002	0.002	0.5900	0.0016	0.0016	0.0000	2016 v.1
CPP Acquisition	Printer	15193	P	40500401	25	0.62	0.002	0.002	0.6200	0.0017	0.0017	0.0000	2016 v.1
McCarran Rent a Car Center	Boiler	15409	A	10300603	25	0.23	0.001	0.001	0.2300	0.0006	0.0006	0.0000	2016 v.1
McCarran Rent a Car Center	Generator	15409	B	20100102	25	0.01	0.000	0.000	0.0100	0.0000	0.0000	0.0000	2016 v.1
Metl Span	Panel manufacturing	15422	A01	30800802	25	1.13	0.003	0.003	1.1300	0.0031	0.0031	0.0000	2016 v.1
Artesian Spas	Spray booth with RTO	15426	A01	30800724	25	0.23	0.001	0.001	0.2300	0.0006	0.0006	0.0000	2016 v.1

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
Red Rock Casino Resort	Boiler	15487	A	10300602	25	0.31	0.001	0.001	0.3100	0.0008	0.0008	0.0000	default value
Red Rock Casino Resort	Generator	15487	B	20300101	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
South Point Hotal and Casino	Boiler	15515	A	10300602	25	0.23	0.001	0.001	0.2300	0.0006	0.0006	0.0000	2016 v.1
South Point Hotal and Casino	Generator	15515	B	20300101	25	2.98	0.008	0.008	2.9800	0.0082	0.0082	0.0000	2016 v.1
World Market Center	Boiler	15541	B	10300602	25	7.12	0.020	0.020	7.1200	0.0195	0.0195	0.0000	2016 v.1
Westgate Las Vegas	Boiler	15541	A	10300603	25	0.29	0.001	0.001	0.2900	0.0008	0.0008	0.0000	2016 v.1
CDW Logistics	Generator	15634	A	20300101	25	1.87	0.005	0.005	1.8700	0.0051	0.0051	0.0000	default value
Manheim Nevada	Generator	15839	C	20100102	25	7.45	0.020	0.020	7.4500	0.0204	0.0204	0.0000	2016 v.1
Manheim Nevada	Heater	15839	B	40201001	25	11.53	0.032	0.032	11.5300	0.0316	0.0316	0.0000	2016 v.1
City of Henderson Downtown	Boiler	15847	B	10300603	25	1.14	0.003	0.003	1.1400	0.0031	0.0031	0.0000	default value
City of Henderson Downtown	Generator	15847	G	20300101	25	0.11	0.000	0.000	0.1100	0.0003	0.0003	0.0000	default value
Centennial Hills Hospital	Boiler	15873	A	10300602	25	26.74	0.073	0.073	26.7400	0.0733	0.0733	0.0000	2016 v.1
Centennial Hills Hospital	Generator	15873	C	20300101	25	0.03	0.000	0.000	0.0300	0.0001	0.0001	0.0000	2016 v.1
Plasticard Locktech	Heater	15876	B	10300603	25	33.83	0.093	0.093	33.5864	0.0920	0.0920	-0.0012	2016 v.1
Plasticard Locktech	Press	15876	A	40202201	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
Veterans Administration	Boiler	15970	B	10300602	25	0.10	0.000	0.000	0.1000	0.0003	0.0003	0.0000	default value
Verizon Business	Generator	15970	A	20300101	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
2755 Las Vegas	Boiler	15999	A	10300602	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
2755 Las Vegas	Generator	15999	B	20300101	25	1.00	0.003	0.003	1.0000	0.0027	0.0027	0.0000	default value
Cosmopolitan Las Vegas	Boiler	16101	A	10300602	25	0.18	0.000	0.000	0.1800	0.0005	0.0005	0.0000	default value
Cosmopolitan Las Vegas	Generator	16101	B	20300101	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
Biodiesel of Las Vegas	Fire Pump	16118	C01	20200102	25	0.04	0.000	0.000	0.0400	0.0001	0.0001	0.0000	default value
Ritchie Brothers	Generator	16172	G	20300101	25	4.68	0.013	0.013	4.7951	0.0131	0.0131	0.0041	2016 v.1
Switch	Generator	16258	B	20300101	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
Beltway Complex	Generator	16290	A	20300101	25	2.34	0.006	0.006	2.3400	0.0064	0.0064	0.0000	2016 v.1
Erickson International	RTO	16295	C	30190013	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
Erickson International	Dryer	16295	B	40200101	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
GE Transport	Parts Washer	16300	A	40201501	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
Switch Communications	Generator	16304	A	20022102	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
Pro Terminal Operators	Loading Rack	16376	A07	40400150	25	0.07	0.000	0.000	0.0700	0.0002	0.0002	0.0000	default value
Treasure Island	Generator	16452	A	20300101	25	0.08	0.000	0.000	0.0800	0.0002	0.0002	0.0000	default value
Clark County Downtown Campus	Boiler	16665	A	10300603	25	12.87	0.035	0.035	12.2140	0.0335	0.0335	-0.0085	2016 v.1
Clark County Downtown Campus	Generator	16665	B	20300101	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
CTC Crushing	Generator	16673	B	20300101	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	2016 v.1
Freeman	Generator	16684	B	20300101	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	2016 v.1
Terra Firma Organics	Generator	16706	B	20300101	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	2016 v.1
Resorts World	Boiler	16925	B	10300602	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	2016 v.1
Resorts World	Generator	16925	A	20300101	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	2016 v.1
Preferred Laminations	Surface Coating	17220	A	40202501	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
Viawest	Generator	17272	A	20300101	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
Blue Diamond Hill Gypsum	Engines	17286	C	20300101	25	18.94	0.052	0.052	18.9400	0.0519	0.0519	0.0000	2016 v.1
Blue Diamond Hill Gypsum	Blasting	17286	A001	30504001	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	2016 v.1
Shelby American	Heater	17347	A03	39990003	25	5.74	0.016	0.016	5.7400	0.0157	0.0157	0.0000	2016 v.1

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
NBC Fourth Realty	Generator	17439	A	20301001	25	13.05	0.036	0.036	13.0500	0.0358	0.0358	0.0000	2016 v.1
Wells Cargo	Drum Mixer	17749	C02	30500257	25	3.91	0.011	0.011	3.9140	0.0107	0.0107	0.0000	2016 v.1
Wells Cargo Lone Mountain	Blasting	17749	B	30504001	25	4.68	0.013	0.013	4.6800	0.0128	0.0128	0.0000	default value
Progress Rail	Parts Washer	17918	A01	10300603	25	0.23	0.001	0.001	0.2300	0.0006	0.0006	0.0000	2016 v.1
Total						1027.43	2.81	2.92	1131.56	3.10	3.23		

Table B2. HA 212 unit-level point source VOC emissions for 2017 and 2023.

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
Certain Teed Gypsum	4	B8	Generator	20200401	25	0.010	0.0000	0.0000	0.0100	0.00	0.0000	0	default value
Certain Teed Gypsum	4	4-L4	Generator	20200401	25	0.190	0.0005	0.0005	0.1900	0.00	0.0005	0	default value
Certain Teed Gypsum	4	4-F1	Grinder	30501502	25	0.310	0.0008	0.0008	0.3399	0.00	0.0009	0.0161	2016 v.1
Certain Teed Gypsum	4	4-G1	Continuous Calciner	30501511	25	0.100	0.0003	0.0003	0.1097	0.00	0.0003	0.0161	2016 v.1
Certain Teed Gypsum	4	4-E11	Impact Mill	30501513	25	0.290	0.0008	0.0008	0.3180	0.00	0.0009	0.0161	2016 v.1
Certain Teed Gypsum	4	4-J3	Dryer	30501520	25	0.700	0.0019	0.0019	0.7676	0.00	0.0021	0.0161	2016 v.1
NV Energy (Clark Station)	7	27	Turbine	20100201	27	0.260	0.0007	0.0008	0.2851	0.00	0.0008	0.0161	2016 v.1
NV Energy (Clark Station)	7	35	Turbine	20100201	27	0.300	0.0008	0.0009	0.3290	0.00	0.0010	0.0161	2016 v.1
NV Energy (Clark Station)	7	38	Turbine	20100201	27	0.300	0.0008	0.0009	0.3290	0.00	0.0010	0.0161	2016 v.1
NV Energy (Clark Station)	7	37	Turbine	20100201	27	0.320	0.0009	0.0009	0.3509	0.00	0.0010	0.0161	2016 v.1
NV Energy (Clark Station)	7	33	Turbine	20100201	27	0.330	0.0009	0.0010	0.3619	0.00	0.0011	0.0161	2016 v.1
NV Energy (Clark Station)	7	29	Turbine	20100201	27	0.340	0.0009	0.0010	0.3728	0.00	0.0011	0.0161	2016 v.1
NV Energy (Clark Station)	7	36	Turbine	20100201	27	0.360	0.0010	0.0011	0.3948	0.00	0.0012	0.0161	2016 v.1
NV Energy (Clark Station)	7	31	Turbine	20100201	27	0.390	0.0011	0.0012	0.4277	0.00	0.0013	0.0161	2016 v.1
NV Energy (Clark Station)	7	28	Turbine	20100201	27	0.440	0.0012	0.0013	0.4825	0.00	0.0014	0.0161	2016 v.1
NV Energy (Clark Station)	7	32	Turbine	20100201	27	0.440	0.0012	0.0013	0.4825	0.00	0.0014	0.0161	2016 v.1
NV Energy (Clark Station)	7	34	Turbine	20100201	27	0.470	0.0013	0.0014	0.5154	0.00	0.0015	0.0161	2016 v.1
NV Energy (Clark Station)	7	4	Turbine	20100201	27	0.520	0.0014	0.0015	0.5702	0.00	0.0017	0.0161	2016 v.1

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
NV Energy (Clark Station)	7	30	Turbine	20100201	27	0.540	0.0015	0.0016	0.5922	0.00	0.0018	0.0161	2016 v.1
NV Energy (Clark Station)	7	7	Turbine	20100201	27	1.830	0.0050	0.0054	2.0068	0.01	0.0059	0.0161	2016 v.1
NV Energy (Clark Station)	7	5	Turbine	20100201	27	2.290	0.0063	0.0068	2.5112	0.01	0.0074	0.0161	2016 v.1
NV Energy (Clark Station)	7	8	Turbine	20100201	27	2.440	0.0067	0.0072	2.6757	0.01	0.0079	0.0161	2016 v.1
NV Energy (Clark Station)	7	6	Turbine	20100201	27	2.530	0.0069	0.0075	2.7744	0.01	0.0082	0.0161	2016 v.1
NV Energy (Clark Station)	7	21	Generator	20200102	27	0.010	0.0000	0.0000	0.0110	0.00	0.0000	0.0161	2016 v.1
NV Energy (Clark Station)	7	45	Generator	20200102	27	0.010	0.0000	0.0000	0.0110	0.00	0.0000	0.0161	2016 v.1
Olin Chlor Alkali Products	9	1	Generator	20200102	25	0.290	0.0008	0.0008	0.3180	0.00	0.0009	0.0161	2016 v.1
Wells Cargo	12	2	Asphalt Oil Heater	30500206	25	0.030	0.0001	0.0001	0.0329	0.00	0.0001	0.0161	2016 v.1
Wells Cargo	12	1	Drum Mixer	30500257	25	8.760	0.0240	0.0240	9.6062	0.03	0.0263	0.0161	2016 v.1
Wells Cargo	12	3	Fugitives	30500298	25	5.360	0.0147	0.0147	5.8778	0.02	0.0161	0.0161	2016 v.1
Kinder Morgan	13	D02	Diesel Pump	20200102	25	0.005	0.0000	0.0000	0.0055	0.00	0.0000	0.0161	2016 v.1
Kinder Morgan	13	B10	Flare Processing	30600904	25	0.028	0.0001	0.0001	0.0307	0.00	0.0001	0.0161	2016 v.1
Kinder Morgan	13	SR04	Thermal Oxidizer	50410312	25	59.300	0.1625	0.1625	65.0284	0.18	0.1782	0.0161	2016 v.1
Titanium Metals Corp.	19	B06	CO Burner/Boiler	10201402	25	0.170	0.0005	0.0005	0.1864	0.00	0.0005	0.0161	2016 v.1
Titanium Metals Corp.	19	C05	Hot Oil Heater	30301201	25	0.059	0.0002	0.0002	0.0647	0.00	0.0002	0.0161	2016 v.1
Titanium Metals Corp.	19	A01	Fugitives	30301299	25	2.141	0.0059	0.0059	2.3478	0.01	0.0064	0.0161	2016 v.1
Northwind Alladin	26	1	Boiler	10300603	25	0.210	0.0006	0.0006	0.2100	0.00	0.0006	0	default value
Circus Circus Hotel and Casino	47	1	Boiler	10300603	25	0.610	0.0017	0.0017	0.6100	0.00	0.0017	0	2016 v.1

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
CCWRD Flamingo Center	54	1	Boiler	10300603	25	3.390	0.0093	0.0093	3.3900	0.01	0.0093	0	2016 v.1
BKEP Materials	67	1	Boiler	10300603	25	0.720	0.0020	0.0020	0.7200	0.00	0.0020	0	2016 v.1
Las Vegas Paving - Blue Diamond	70	B12	Drum Mixer	30500257	25	4.970	0.0136	0.0136	4.9700	0.01	0.0136	0	2016 v.1
Golden Nugget Hotel and Casino	81	1	Boiler	10300603	25	0.150	0.0004	0.0004	0.1500	0.00	0.0004	0	2016 v.1
Horseshoe Club	85	1	Boiler	10300603	25	0.960	0.0026	0.0026	0.9600	0.00	0.0026	0	2016 v.1
Tronox	95	A07	Boiler	10300602	25	0.040	0.0001	0.0001	0.0400	0.00	0.0001	0	2016 v.1
Tronox	95	A05	Boiler	10300602	25	0.930	0.0025	0.0025	0.9300	0.00	0.0025	0	2016 v.1
Tronox	95	A01	Generator	20300101	25	0.001	0.0000	0.0000	0.0010	0.00	0.0000	0	2016 v.1
Tronox	95	A02	Generator	20300101	25	0.010	0.0000	0.0000	0.0100	0.00	0.0000	0	2016 v.1
Tronox	95	A03	Generator	20300101	25	0.010	0.0000	0.0000	0.0100	0.00	0.0000	0	2016 v.1
Tronox	95	A04	Generator	20300101	25	0.030	0.0001	0.0001	0.0300	0.00	0.0001	0	2016 v.1
Tronox	95	A15	Chem. Manufacturing	30107002	25	0.070	0.0002	0.0002	0.0700	0.00	0.0002	0	2016 v.1
Tronox	95	A10	Chem. Manufacturing	30107002	25	0.330	0.0009	0.0009	0.3300	0.00	0.0009	0	2016 v.1
Westgate Las Vegas	101	B	Boiler	10300603	25	0.580	0.0016	0.0016	0.5800	0.00	0.0016	0	2016 v.1
Westgate Las Vegas	101	G	Generator	20100102	25	0.010	0.0000	0.0000	0.0100	0.00	0.0000	0	2016 v.1
Las Vegas Paving - 5th Street	104	E02	Fire Pump	20200102	25	0.030	0.0001	0.0001	0.0300	0.00	0.0001	0	2016 v.1
Las Vegas Paving - 5th Street	104	E01	Drum Mixer	30500205	25	5.190	0.0142	0.0142	5.1900	0.01	0.0142	0	2016 v.1
Las Vegas Paving - 5th Street	104	H01	Oil Heater	30500206	25	0.030	0.0001	0.0001	0.0300	0.00	0.0001	0	2016 v.1
Las Vegas Paving - 5th Street	104	B19	Asphalt Silos	30500213	25	2.110	0.0058	0.0058	2.1100	0.01	0.0058	0	2016 v.1
Las Vegas Paving - 5th Street	104	B17	Truck Loadout	30500214	25	0.680	0.0019	0.0019	0.6800	0.00	0.0019	0	2016 v.1

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
Las Vegas Paving - 5th Street	104	E03	Drum Dryer	39001089	25	0.520	0.0014	0.0014	0.5200	0.00	0.0014	0	2016 v.1
Las Vegas Paving - 5th Street	104	G01	UST	40600706	25	0.140	0.0004	0.0004	0.1400	0.00	0.0004	0	2016 v.1
Las Vegas Paving - Lone Mountain	105	C	Generator	20200102	25	1.690	0.0046	0.0046	1.6900	0.00	0.0046	0	2016 v.1
Las Vegas Paving - Lone Mountain	105	B012	Drum Dryer	30500205	25	3.320	0.0091	0.0091	3.3200	0.01	0.0091	0	2016 v.1
Las Vegas Paving - Lone Mountain	105	B011	Oil Heater	30500209	25	0.020	0.0001	0.0001	0.0243	0.00	0.0001	0.0357	2016 v.1
Las Vegas Paving - Lone Mountain	105	B013	Asphalt Silos	30500213	25	0.080	0.0002	0.0002	0.0971	0.00	0.0003	0.0357	2016 v.1
McCarran International Airport	108	A	Boiler	10300602	25	0.800	0.0022	0.0022	0.9714	0.00	0.0027	0.0357	2016 v.1
McCarran International Airport	108	E	Generator	20200102	25	0.140	0.0004	0.0004	0.1700	0.00	0.0005	0.0357	2016 v.1
McCarran International Airport	108	S01	Paint Booth	40201101	25	0.170	0.0005	0.0005	0.2064	0.00	0.0006	0.0357	2016 v.1
McCarran International Airport	108	W01	AST	40600401	25	0.190	0.0005	0.0005	0.2307	0.00	0.0006	0.0357	2016 v.1
Nellis AFB	114	RB-C	Nat gas boilers	10300602	25	0.400	0.0011	0.0011	0.4857	0.00	0.0013	0.0357	2016 v.1
Nellis AFB	114	G	Internal Combustion	20300301	25	0.310	0.0008	0.0008	0.2212	0.00	0.0006	-0.047765393	IPM
Nellis AFB	114	N	Hush House	20400110	25	0.530	0.0015	0.0015	0.2002	0.00	0.0005	-0.103711417	IPM
Nellis AFB	114	O	Misc Chemicals	24600000	25	6.140	0.0168	0.0168	7.4552	0.02	0.0204	0.0357	2016 v.1
Nellis AFB	114	A047	Drum Mixer	30500205	25	0.120	0.0003	0.0003	0.1457	0.00	0.0004	0.0357	2016 v.1
Nellis AFB	114	M	Degreasers	40100336	25	0.080	0.0002	0.0002	0.0971	0.00	0.0003	0.0357	2016 v.1
Nellis AFB	114	D	Surface coating	40202501	25	1.400	0.0038	0.0038	1.6999	0.00	0.0047	0.0357	2016 v.1
Nellis AFB	114	J	Fuel dispensing	40688801	25	5.300	0.0145	0.0145	6.4353	0.02	0.0176	0.0357	2016 v.1

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
SLS Las Vegas	133	A	Boiler	10300602	25	0.250	0.0007	0.0007	0.1434	0.00	0.0004	-0.07107463	IPM
SLS Las Vegas	133	B	Generator	20300101	25	0.050	0.0001	0.0001	0.0286	0.00	0.0001	-0.071434142	IPM
University Medical Center	142	A	Boiler	10300603	25	0.410	0.0011	0.0011	0.4978	0.00	0.0014	0.0357	2016 v.1
University Medical Center	142	B	Generator	20300101	25	0.080	0.0002	0.0002	0.0971	0.00	0.0003	0.0357	2016 v.1
Las Vegas Paving	186	B013	Drum Mixer	30500205	25	2.040	0.0056	0.0056	2.4770	0.01	0.0068	0.0357	2016 v.1
Las Vegas Paving	186	B023	Oil Heater	30500208	25	0.010	0.0000	0.0000	0.0121	0.00	0.0000	0.0357	2016 v.1
Las Vegas Paving	186	B017	Waste Silo	30500213	25	0.060	0.0002	0.0002	0.0729	0.00	0.0002	0.0357	2016 v.1
Las Vegas Paving	186	B020	Truck Loadout	30500214	25	0.260	0.0007	0.0007	0.3157	0.00	0.0009	0.0357	2016 v.1
Caesars Consolidated	257	1	Boiler	10300603	25	2.000	0.0055	0.0055	2.4284	0.01	0.0067	0.0357	2016 v.1
Mirage/Treasure Island	282	1	Boiler	10300603	25	1.010	0.0028	0.0028	1.2263	0.00	0.0034	0.0357	2016 v.1
Brady Linen Services	322	1	Dryer	30504033	25	1.480	0.0041	0.0041	1.7970	0.00	0.0049	0.0357	2016 v.1
Catalina Plastic and Coating	323	1	Plastics	40201399	25	11.130	0.0305	0.0305	13.5140	0.04	0.0370	0.0357	2016 v.1
Las Vegas Cogeneration	329	10	Generator	20100102	51	0.010	0.0000	0.0001	0.0121	0.00	0.0001	0.0357	2016 v.1
Las Vegas Cogeneration	329	11	Generator	20100102	51	0.020	0.0001	0.0001	0.0243	0.00	0.0001	0.0357	2016 v.1
Las Vegas Cogeneration	329	1	Turbine	20100201	51	0.680	0.0019	0.0038	0.8257	0.00	0.0046	0.0357	2016 v.1
Las Vegas Cogeneration	329	3	Turbine	20100201	51	0.980	0.0027	0.0055	1.1899	0.00	0.0067	0.0357	2016 v.1
Las Vegas Cogeneration	329	5	Turbine	20100201	51	1.340	0.0037	0.0075	1.6270	0.00	0.0091	0.0357	2016 v.1
Las Vegas Cogeneration	329	6	Turbine	20100201	51	1.350	0.0037	0.0075	1.6392	0.00	0.0092	0.0357	2016 v.1
Las Vegas Cogeneration	329	4	Turbine	20100201	51	1.410	0.0039	0.0079	1.7120	0.00	0.0096	0.0357	2016 v.1
Boral Roofing	346	B18	Curing Tunnel	30500850	25	0.010	0.0000	0.0000	0.0121	0.00	0.0000	0.0357	2016 v.1

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
Boral Roofing	346	AB	Surface coating	40299995	25	2.860	0.0078	0.0078	3.4726	0.01	0.0095	0.0357	2016 v.1
Aggregate Industries	372	10	Boiler	10300602	25	0.120	0.0003	0.0003	0.1457	0.00	0.0004	0.0357	2016 v.1
Aggregate Industries	372	1	Generator	20100102	25	3.290	0.0090	0.0090	3.9947	0.01	0.0109	0.0357	2016 v.1
Aggregate Industries	372	4	Mineral Products	30500208	25	0.000	0.0000	0.0000	0.0000	0.00	0.0000	0	2016 v.1
Aggregate Industries	372	5	Mineral Products	30500208	25	0.010	0.0000	0.0000	0.0113	0.00	0.0000	0.022	2016 v.1
Aggregate Industries	372	2	Mineral Products	30500208	25	0.015	0.0000	0.0000	0.0170	0.00	0.0000	0.022	2016 v.1
Aggregate Industries	372	3	Mineral Products	30500242	25	0.015	0.0000	0.0000	0.0172	0.00	0.0000	0.0243	2016 v.1
Aggregate Industries	372	13	Mineral Products	30502599	25	0.030	0.0001	0.0001	0.0344	0.00	0.0001	0.0243	2016 v.1
Saguaro Power Company	393	5	Boiler	10100601	27	0.276	0.0008	0.0008	0.3162	0.00	0.0009	0.0243	2016 v.1
Saguaro Power Company	393	6	Boiler	10100602	27	0.137	0.0004	0.0004	0.1570	0.00	0.0005	0.0243	2016 v.1
Saguaro Power Company	393	3	Starter	20100102	27	0.005	0.0000	0.0000	0.0057	0.00	0.0000	0.0243	2016 v.1
Saguaro Power Company	393	4	Starter	20100102	27	0.006	0.0000	0.0000	0.0069	0.00	0.0000	0.0243	2016 v.1
Saguaro Power Company	393	7	Generator	20100102	27	0.050	0.0001	0.0001	0.0573	0.00	0.0002	0.0243	2016 v.1
Saguaro Power Company	393	1	Turbine	20100201	27	3.875	0.0106	0.0115	4.4400	0.01	0.0131	0.0243	2016 v.1
Saguaro Power Company	393	2	Turbine	20100201	27	3.881	0.0106	0.0115	4.4468	0.01	0.0132	0.0243	2016 v.1
City of Las Vegas WPCF	402	2	Generator	20200102	25	0.070	0.0002	0.0002	0.0802	0.00	0.0002	0.0243	2016 v.1
City of Las Vegas WPCF	402	3	Generator	20200202	25	0.010	0.0000	0.0000	0.0115	0.00	0.0000	0.0243	2016 v.1
City of Las Vegas WPCF	402	5	Waste Flare	50100789	25	0.340	0.0009	0.0009	0.3896	0.00	0.0011	0.0243	2016 v.1

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
City of Las Vegas WPCF	402	8	Boilers	50100799	25	0.110	0.0003	0.0003	0.1260	0.00	0.0003	0.0243	2016 v.1
City of Las Vegas WPCF	402	7	Boilers	50100799	25	0.210	0.0006	0.0006	0.2406	0.00	0.0007	0.0243	2016 v.1
City of Las Vegas WPCF	402	6	Blower Engines	50100799	25	3.640	0.0100	0.0100	4.1096	0.01	0.0113	0.0215	2016 v.1
Nikkiso Cryo	404	1	Generator	20200102	25	0.390	0.0011	0.0011	0.4382	0.00	0.0012	0.0206	2016 v.1
Nevada Sun Peak Partnerships	423	3	Turbine	20100201	37	0.060	0.0002	0.0002	0.0674	0.00	0.0003	0.0206	2016 v.1
Nevada Sun Peak Partnerships	423	2	Turbine	20100201	37	0.080	0.0002	0.0003	0.0899	0.00	0.0004	0.0206	2016 v.1
Nevada Sun Peak Partnerships	423	1	Turbine	20100201	37	0.110	0.0003	0.0004	0.1236	0.00	0.0005	0.0206	2016 v.1
Hard Rock Hotel and Casino	510	A	Boiler	10300603	25	0.230	0.0006	0.0006	0.2602	0.00	0.0007	0.0219	2016 v.1
Hard Rock Hotel and Casino	510	B	Generator	20300101	25	0.020	0.0001	0.0001	0.0226	0.00	0.0001	0.0219	2016 v.1
Texas Station Casino	531	A	Boiler	10300603	25	0.400	0.0011	0.0011	0.4526	0.00	0.0012	0.0219	2016 v.1
Texas Station Casino	531	B	Generator	20300101	25	0.020	0.0001	0.0001	0.0226	0.00	0.0001	0.0219	2016 v.1
Citibank The Lakes	546	A	Generator	20300101	25	0.010	0.0000	0.0000	0.0113	0.00	0.0000	0.0219	2016 v.1
Rio All Suites Hotel and Casino	555	A	Boiler	10300603	25	1.580	0.0043	0.0043	1.7876	0.00	0.0049	0.0219	2016 v.1
Rio All Suites Hotel and Casino	555	C	Generator	20300101	25	0.050	0.0001	0.0001	0.0566	0.00	0.0002	0.0219	2016 v.1
Kurt Segler Water Reclamation	558	B	Generator	20200102	25	0.900	0.0025	0.0025	1.0183	0.00	0.0028	0.0219	2016 v.1
Kurt Segler Water Reclamation	558	B01	Waste water treatment	50100765	25	0.240	0.0007	0.0007	0.2715	0.00	0.0007	0.0219	2016 v.1
Stratosphere Hotel and Casino	564	A	Boiler	10300603	25	0.330	0.0009	0.0009	0.3734	0.00	0.0010	0.0219	2016 v.1
Stratosphere Hotel and Casino	564	B	Generator	20300101	25	0.170	0.0005	0.0005	0.1923	0.00	0.0005	0.0219	2016 v.1

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
Aggregate Industries - Gowan	587	A08	Drum Mixer	30500205	25	2.980	0.0082	0.0082	3.3716	0.01	0.0092	0.0219	2016 v.1
Aggregate Industries - Gowan	587	E	Asphalt Oil Heater	30500208	25	0.070	0.0002	0.0002	0.0792	0.00	0.0002	0.0219	2016 v.1
Aggregate Industries - Gowan	587	A12	Asphalt Silos	30500212	25	4.380	0.0120	0.0120	4.9555	0.01	0.0136	0.0219	2016 v.1
Las Vegas Review Journal	588	D	Generator	20300101	25	0.010	0.0000	0.0000	0.0113	0.00	0.0000	0.0219	2016 v.1
Las Vegas Review Journal	588	B	Parts Washer	40500417	25	8.080	0.0221	0.0221	9.1417	0.03	0.0250	0.0219	2016 v.1
Berry Plastics Corporation	597	F01	Generator	20300101	25	0.010	0.0000	0.0000	0.0113	0.00	0.0000	0.0219	2016 v.1
Berry Plastics Corporation	597	E01	Offset Printing	40500802	25	5.630	0.0154	0.0154	6.3698	0.02	0.0175	0.0219	2016 v.1
Palace Station Hotel and Casino	605	A	Boiler	10300603	25	0.490	0.0013	0.0013	0.5544	0.00	0.0015	0.0219	2016 v.1
Palace Station Hotel and Casino	605	B	Generator	20300101	25	0.020	0.0001	0.0001	0.0226	0.00	0.0001	0.0219	2016 v.1
Gold Coast Hotel and Casino	606	A	Boiler	10300603	25	0.270	0.0007	0.0007	0.0680	0.00	0.0002	-0.1247	IPM
Gold Coast Hotel and Casino	606	B	Generator	20300101	25	0.060	0.0002	0.0002	0.0228	0.00	0.0001	-0.10343607	IPM
Sams Town Hotel and Casino	616	A	Boiler	10300603	25	0.230	0.0006	0.0006	0.0582	0.00	0.0002	-0.124481959	IPM
Sams Town Hotel and Casino	616	B	Generator	20300101	25	0.010	0.0000	0.0000	0.0025	0.00	0.0000	-0.124568207	IPM
Santa Fe Station	621	A	Boiler	10300603	25	0.670	0.0018	0.0018	0.6780	0.00	0.0019	0.002	2016 v.1
Santa Fe Station	621	B	Generator	20300101	25	0.010	0.0000	0.0000	0.0100	0.00	0.0000	0	default value
University of Nevada, Las Vegas	634	A	Boiler	10300603	25	0.740	0.0020	0.0020	0.7400	0.00	0.0020	0	2016 v.1

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
University of Nevada, Las Vegas	634	B	Generator	20300101	25	0.060	0.0002	0.0002	0.0600	0.00	0.0002	0	2016 v.1
Orleans Hotel and Casino	641	A	Boiler	10300603	25	0.500	0.0014	0.0014	0.5000	0.00	0.0014	0	2016 v.1
Orleans Hotel and Casino	641	B	Generator	20300101	25	0.010	0.0000	0.0000	0.0100	0.00	0.0000	0	2016 v.1
Venetian Hotel and Casino	697	B	Boiler	10300603	25	3.170	0.0087	0.0087	3.1700	0.01	0.0087	0	2016 v.1
Venetian Hotel and Casino	697	C	Generator	20300101	25	0.120	0.0003	0.0003	0.1200	0.00	0.0003	0	2016 v.1
Verizon Business	726	A	Generator	20300101	25	0.020	0.0001	0.0001	0.0200	0.00	0.0001	0	2016 v.1
Nevada Color Litho	754	A05	Printing Press	40500433	25	18.860	0.0517	0.0517	18.8600	0.05	0.0517	0	2016 v.1
JW Marriott Las Vegas	755	A	Boiler	10300603	25	0.340	0.0009	0.0009	0.3400	0.00	0.0009	0	default value
JW Marriott Las Vegas	755	B	Generator	20300101	25	0.020	0.0001	0.0001	0.0200	0.00	0.0001	0	default value
Suncoast Hotel and Casino	775	A	Boiler	10300603	25	0.230	0.0006	0.0006	0.2300	0.00	0.0006	0	default value
Suncoast Hotel and Casino	775	B	Generator	20300101	25	0.030	0.0001	0.0001	0.0300	0.00	0.0001	0	default value
Viawest	777	A	Generator	20300101	25	0.030	0.0001	0.0001	0.0300	0.00	0.0001	0	2016 v.1
Cancun Resort	788	A	Boiler	10300603	25	0.160	0.0004	0.0004	0.1600	0.00	0.0004	0	2016 v.1
Cancun Resort	788	B	Generator	20300101	25	0.020	0.0001	0.0001	0.0200	0.00	0.0001	0	2016 v.1
Clearwater Paper	807	A10	Boiler	10200602	25	0.560	0.0015	0.0015	0.5600	0.00	0.0015	0	2016 v.1
Clearwater Paper	807	A08	Air heaters	30790003	25	6.930	0.0190	0.0190	6.9300	0.02	0.0190	0	2016 v.1
Clearwater Paper	807	F	Paper process fugitives	30799998	25	14.580	0.0399	0.0399	14.5800	0.04	0.0399	0	2016 v.1
MGM Grand/New York New York	825	A	Boiler	10300603	25	5.840	0.0160	0.0160	5.8400	0.02	0.0160	0	default value
MGM Grand/New York New York	825	E	Turbine	20100201	25	0.850	0.0023	0.0023	0.8500	0.00	0.0023	0	2016 v.1

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
MGM Grand/New York New York	825	B	Generator	20300101	25	0.550	0.0015	0.0015	0.5500	0.00	0.0015	0	2016 v.1
MGM Grand/New York New York	825	C	Paint booth	40201101	25	1.690	0.0046	0.0046	1.6900	0.00	0.0046	0	2016 v.1
MGM Grand/New York New York	825	D	Tank	40600401	25	1.930	0.0053	0.0053	1.9300	0.01	0.0053	0	2016 v.1
Univeral Urethane	859	A	Molding machines	30800802	25	14.370	0.0394	0.0394	14.3700	0.04	0.0394	0	2016 v.1
Univeral Urethane	859	B	Spray painting booths	40202201	25	7.880	0.0216	0.0216	7.8800	0.02	0.0216	0	2016 v.1
Sunset Station	869	A	Boiler	10300603	25	0.320	0.0009	0.0009	0.3200	0.00	0.0009	0	2016 v.1
Sunset Station	869	B	Generator	20300101	25	0.020	0.0001	0.0001	0.0200	0.00	0.0001	0	2016 v.1
Yesco	974	A	Spray painting booths	40200101	25	4.820	0.0132	0.0132	4.8200	0.01	0.0132	0	2016 v.1
West Rock	1055	A	Printing Press	40500501	25	10.860	0.0298	0.0298	10.8600	0.03	0.0298	0	2016 v.1
Republic Services Transfer Station	1087	B	Boiler	10300603	25	0.010	0.0000	0.0000	0.0100	0.00	0.0000	0	2016 v.1
Republic Services Transfer Station	1087	G	Generator	20300101	25	0.440	0.0012	0.0012	0.4400	0.00	0.0012	0	2016 v.1
Republic Services Transfer Station	1087	A10	Spray painting booths	40201601	25	4.830	0.0132	0.0132	4.8300	0.01	0.0132	0	2016 v.1
Republic Services Transfer Station	1087	A11	UST	40600306	25	0.380	0.0010	0.0010	0.3800	0.00	0.0010	0	2016 v.1
Las Vegas Color Graphics	1149	A	Printing Press	40500411	25	7.300	0.0200	0.0200	7.3000	0.02	0.0200	0	2016 v.1
St Rose Dominican Siena	1500	A	Boiler	10300603	25	0.760	0.0021	0.0021	0.7600	0.00	0.0021	0	2016 v.1
St Rose Dominican Siena	1500	B	Generator	20300101	25	0.030	0.0001	0.0001	0.0300	0.00	0.0001	0	2016 v.1
Green Valley Ranch Resort	1501	A	Boiler	10300603	25	0.220	0.0006	0.0006	0.2200	0.00	0.0006	0	2016 v.1
Green Valley Ranch Resort	1501	B	Generator	20300101	25	0.010	0.0000	0.0000	0.0100	0.00	0.0000	0	2016 v.1
Palms Casino Resort	1522	A	Boiler	10300603	25	0.390	0.0011	0.0011	0.3900	0.00	0.0011	0	2016 v.1

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
Palms Casino Resort	1522	B	Generator	20300101	25	0.010	0.0000	0.0000	0.0100	0.00	0.0000	0	2016 v.1
Boulder Station Hotel and Casino	1524	A	Boiler	10300603	25	0.150	0.0004	0.0004	0.1500	0.00	0.0004	0	2016 v.1
Boulder Station Hotel and Casino	1524	B	Generator	20300101	25	0.030	0.0001	0.0001	0.0300	0.00	0.0001	0	2016 v.1
Mountain View Hospital	1569	A	Boiler	10300603	25	0.220	0.0006	0.0006	0.2200	0.00	0.0006	0	2016 v.1
Mountain View Hospital	1569	B	Generator	20300101	25	0.030	0.0001	0.0001	0.0300	0.00	0.0001	0	2016 v.1
Lasfuel McCarran Tank Farm	1589	C	Generator	20300101	25	0.020	0.0001	0.0001	0.0200	0.00	0.0001	0	2016 v.1
Lasfuel McCarran Tank Farm	1589	B06	Thermal Oxidizer	40400153	25	0.000	0.0000	0.0000	0.0000	0.00	0.0000	0	2016 v.1
Lasfuel McCarran Tank Farm	1589	A	Tank	40400199	25	14.300	0.0392	0.0392	14.3000	0.04	0.0392	0	2016 v.1
Lasfuel McCarran Tank Farm	1589	B	Loading Rack	40400250	25	0.490	0.0013	0.0013	0.4900	0.00	0.0013	0	2016 v.1
Wynn Las Vegas	1624	A	Boiler	10300602	25	1.190	0.0033	0.0033	1.1900	0.00	0.0033	0	2016 v.1
Wynn Las Vegas	1624	C	Generator	20100102	25	0.320	0.0009	0.0009	0.3200	0.00	0.0009	0	2016 v.1
Wynn Las Vegas	1624	R	Dry Cleaning	40100103	25	0.240	0.0007	0.0007	0.2400	0.00	0.0007	0	2016 v.1
Wynn Las Vegas	1624	F	AST	40600306	25	0.070	0.0002	0.0002	0.0700	0.00	0.0002	0	2016 v.1
North Las Vegas Airport	9596	A	Tank	40600706	25	1.400	0.0038	0.0038	1.4000	0.00	0.0038	0	2016 v.1
Henderson Executive Airport	9603	A	Tank	40600706	25	0.860	0.0024	0.0024	0.8600	0.00	0.0024	0	2016 v.1
Brady Linen Services	10201	B	Boiler	10200602	25	0.880	0.0024	0.0024	0.8800	0.00	0.0024	0	2016 v.1
Brady Linen Services	10201	M	Dry Cleaning	41000115	25	1.760	0.0048	0.0048	1.8044	0.00	0.0049	0.0042	2016 v.1
Brady Linen Services	10201	D	Dryer	41000130	25	0.990	0.0027	0.0027	1.2228	0.00	0.0034	0.0392	2016 v.1
Republic Services (Sunrise)	15033	1	Flare	50300601	25	1.190	0.0033	0.0033	1.1900	0.00	0.0033	0	default value

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
CPP Acquisition	15193	D	Dryer	40500101	25	0.670	0.0018	0.0018	0.6700	0.00	0.0018	0	2016 v.1
CPP Acquisition	15193	P	Printer	40500401	25	20.490	0.0561	0.0561	20.4900	0.06	0.0561	0	2016 v.1
McCarran Rent a Car Center	15409	A	Boiler	10300603	25	0.010	0.0000	0.0000	0.0100	0.00	0.0000	0	2016 v.1
McCarran Rent a Car Center	15409	T	Tank	40600306	25	8.390	0.0230	0.0230	8.3900	0.02	0.0230	0	2016 v.1
Metl Span	15422	A01	Panel manufacturing	30800802	25	2.420	0.0066	0.0066	2.4200	0.01	0.0066	0	2016 v.1
Metl Span	15422	A05	Panel Coating	30801005	25	2.180	0.0060	0.0060	2.1800	0.01	0.0060	0	2016 v.1
Artesian Spas	15426	A06	Frame and skirting process	24010900	25	0.660	0.0018	0.0018	0.6600	0.00	0.0018	0	2016 v.1
Artesian Spas	15426	A01	Spray booth with RTO	30800724	25	1.530	0.0042	0.0042	1.5300	0.00	0.0042	0	default value
Artesian Spas	15426	A05	Plumbing system installation	30800799	25	4.780	0.0131	0.0131	4.7800	0.01	0.0131	0	2016 v.1
Red Rock Casino Resort	15487	A	Boiler	10300602	25	0.490	0.0013	0.0013	0.4900	0.00	0.0013	0	default value
Red Rock Casino Resort	15487	B	Generator	20300101	25	0.030	0.0001	0.0001	0.0300	0.00	0.0001	0	default value
South Point Hotal and Casino	15515	A	Boiler	10300602	25	0.530	0.0015	0.0015	0.5300	0.00	0.0015	0	2016 v.1
South Point Hotal and Casino	15515	B	Generator	20300101	25	0.030	0.0001	0.0001	0.0300	0.00	0.0001	0	2016 v.1
World Market Center	15541	A	Boiler	10300602	25	0.020	0.0001	0.0001	0.0200	0.00	0.0001	0	2016 v.1
World Market Center	15541	B	Generator	20300101	25	0.060	0.0002	0.0002	0.0600	0.00	0.0002	0	default value
CDW Logistics	15634	A	Generator	20300101	25	0.040	0.0001	0.0001	0.0400	0.00	0.0001	0	default value
Manheim Nevada	15839	C	Generator	20100102	25	0.020	0.0001	0.0001	0.0200	0.00	0.0001	0	default value
Manheim Nevada	15839	B	Heater	40201001	25	0.280	0.0008	0.0008	0.2800	0.00	0.0008	0	default value
Manheim Nevada	15839	A	Paint booth	40201601	25	4.430	0.0121	0.0121	4.4300	0.01	0.0121	0	default value

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
Manheim Nevada	15839	D	AST	40600401	25	0.990	0.0027	0.0027	0.9900	0.00	0.0027	0	default value
City of Henderson Downtown	15847	B	Boiler	10300603	25	0.230	0.0006	0.0006	0.2300	0.00	0.0006	0	2016 v.1
City of Henderson Downtown	15847	G	Generator	20300101	25	0.030	0.0001	0.0001	0.0300	0.00	0.0001	0	default value
Centennial Hills Hospital	15873	A	Boiler	10300602	25	0.320	0.0009	0.0009	0.3200	0.00	0.0009	0	default value
Centennial Hills Hospital	15873	C	Generator	20300101	25	0.020	0.0001	0.0001	0.0200	0.00	0.0001	0	default value
Plasticard Locktech	15876	B	Heater	10300603	25	0.100	0.0003	0.0003	0.1000	0.00	0.0003	0	default value
Plasticard Locktech	15876	A	Press	40202201	25	10.640	0.0292	0.0292	10.6400	0.03	0.0292	0	default value
Veterans Administration	15970	A	Boiler	10300602	25	0.130	0.0004	0.0004	0.1298	0.00	0.0004	-0.0002	2016 v.1
Veterans Administration	15970	B	Generator	20300101	25	0.740	0.0020	0.0020	0.7391	0.00	0.0020	-0.0002	2016 v.1
2755 Las Vegas	15999	A	Boiler	10300602	25	0.000	0.0000	0.0000	0.0000	0.00	0.0000	0.018	2016 v.1
2755 Las Vegas	15999	B	Generator	20300101	25	0.030	0.0001	0.0001	0.0332	0.00	0.0001	0.018	2016 v.1
Cosmopolitan Las Vegas	16101	A	Boiler	10300602	25	0.900	0.0025	0.0025	0.9972	0.00	0.0027	0.018	2016 v.1
Cosmopolitan Las Vegas	16101	B	Generator	20300101	25	0.010	0.0000	0.0000	0.0111	0.00	0.0000	0.018	2016 v.1
Biodiesel of Las Vegas	16118	C01	Fire Pump	20200102	25	0.040	0.0001	0.0001	0.0400	0.00	0.0001	0	default value
Ritchie Brothers	16172	A01	Paint booth	40201601	25	0.960	0.0026	0.0026	0.9600	0.00	0.0026	0	default value
Switch	16258	B	Generator	20300101	25	0.130	0.0004	0.0004	0.1197	0.00	0.0003	-0.0132	2016 v.1
Beltway Complex	16290	A	Generator	20300101	25	0.040	0.0001	0.0001	0.0369	0.00	0.0001	-0.013	2016 v.1
Beltway Complex	16290	A14	AST	40600306	25	0.290	0.0008	0.0008	0.2900	0.00	0.0008	0	2016 v.1
Erickson International	16295	B	RTO	30190013	25	0.020	0.0001	0.0001	0.0200	0.00	0.0001	0	default value
Erickson International	16295	C	Dryer	40200101	25	0.020	0.0001	0.0001	0.0200	0.00	0.0001	0	2016 v.1

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
Erickson International	16295	A	Laminator	40200701	25	1.970	0.0054	0.0054	1.9700	0.01	0.0054	0	2016 v.1
GE Transport	16300	A	Parts Washer	40201501	25	1.040	0.0028	0.0028	1.0400	0.00	0.0028	0	default value
Switch Communications	16304	A	Generator	20022102	25	0.510	0.0014	0.0014	0.5024	0.00	0.0014	-0.0025	2016 v.1
Pro Terminal Operators	16376	A07	Loading Rack	40400150	25	15.390	0.0422	0.0422	15.7778	0.04	0.0432	0.0042	2016 v.1
Pro Terminal Operators	16376	A	Tanks	40400178	25	12.180	0.0334	0.0334	12.2604	0.03	0.0336	0.0011	2016 v.1
Treasure Island	16452	A	Boiler	10300603	25	0.630	0.0017	0.0017	0.6459	0.00	0.0018	0.0042	2016 v.1
Treasure Island	16452	C01	Spray booth	40200102	25	0.290	0.0008	0.0008	0.2973	0.00	0.0008	0.0042	2016 v.1
Clark County Downtown Campus	16665	A	Boiler	10300603	25	0.710	0.0019	0.0019	0.7100	0.00	0.0019	0	default value
Clark County Downtown Campus	16665	B	Generator	20300101	25	0.110	0.0003	0.0003	0.1100	0.00	0.0003	0	default value
CTC Crushing	16673	B	Generator	20300101	25	0.610	0.0017	0.0017	0.6100	0.00	0.0017	0	default value
Freeman	16684	B	Generator	20300101	25	0.010	0.0000	0.0000	0.0100	0.00	0.0000	0	default value
Freeman	16684	D	Spray booth	40200102	25	0.660	0.0018	0.0018	0.6600	0.00	0.0018	0	default value
Terra Firma Organics	16706	B	Generator	20300101	25	0.160	0.0004	0.0004	0.1600	0.00	0.0004	0	default value
Resorts World	16925	B	Boiler	10300602	25	0.000	0.0000	0.0000	0.0000	0.00	0.0000	0	default value
Resorts World	16925	A	Generator	20300101	25	0.000	0.0000	0.0000	0.0000	0.00	0.0000	0	default value
Preferred Laminations	17220	A	Surface Coating	40202501	25	4.410	0.0121	0.0121	4.4100	0.01	0.0121	0	default value
Viawest Lone Mountain Data Center	17272	A	Generator	20300101	25	0.030	0.0001	0.0001	0.0300	0.00	0.0001	0	default value
Blue Diamond Hill Gypsum	17286	C	Engines	20300101	25	4.280	0.0117	0.0117	4.4084	0.01	0.0121	0.005	2016 v.1
Shelby American	17347	A	Spray booth	40201606	25	1.540	0.0042	0.0042	1.5862	0.00	0.0043	0.005	2016 v.1

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2023 TPY	2023 TPD	2023 summer TPD	2016-2023 Per year Growth Factor	Source for Growth Factor
Shelby American	17347	B01	AST	40600306	25	0.130	0.0004	0.0004	0.1339	0.00	0.0004	0.005	2016 v.1
NBC Fourth Realty	17439	A	Generator	20301001	25	0.160	0.0004	0.0004	0.1600	0.00	0.0004	0	default value
Wells Cargo Lone Mountain	17749	B	Engines	20300101	25	0.170	0.0005	0.0005	0.1700	0.00	0.0005	0	2016 v.1
Wells Cargo Lone Mountain	17749	C02	Blasting	30504001	25	0.000	0.0000	0.0000	0.0000	0.00	0.0000	0	2016 v.1
Progress Rail	17918	A01	Parts Washer	10300603	25	0.000	0.0000	0.0000	0.0000	0.00	0.0000	0	2016 v.1
Total						447.03	1.22	1.25	470.91	1.29	1.32		

ATTACHMENT B:

Attainment Demonstration Technical Support Document

Prepared for:

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June 28, 2024
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Technical Support Document: Attainment Demonstration for the Clark County Ozone State Implementation Plan

Final

Bright ideas. Sustainable change.

Technical Support Document: Attainment Demonstration for the Clark County Ozone State Implementation Plan

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1.0 INTRODUCTION

1.1 Purpose

In June 2018, the US Environmental Protection Agency (EPA) designated a portion of Clark County, Nevada as a Marginal Nonattainment area under the 2015 ozone National Ambient Air Quality Standard (NAAQS) of 0.070 parts per million by volume (ppm) (Federal Register, 2018). The nonattainment boundary is defined as the Las Vegas Valley (LVV), hydrographic area 212 (HA 212), as recommended by the Nevada Division of Environmental Protection (NDEP) and Clark County (2018). In July 2022, the EPA reclassified the Clark County Nonattainment Area (CCNAA) from Marginal to Moderate due to continued exceedances of the standard through 2020 (Federal Register, 2022, 2023). Moderate areas are subject to additional reporting, management, and emission reduction requirements, including the submittal and approval of an ozone State Implementation Plan (SIP). An approvable SIP must demonstrate, according to photochemical modeling and other weight-of-evidence analyses, that the area will attain the NAAQS by August 3, 2024.

The purpose of this project was to conduct and document the photochemical modeling and ancillary weight-of-evidence analyses that support an ozone attainment demonstration for the CCNAA Moderate Ozone SIP. The project included developing and modeling a set of future control measures, including a mandatory 15% Rate-of-Progress (ROP) Plan for volatile organic compound (VOC) emissions, and developing an on-road mobile source conformity budget. The project was conducted by Ramboll Americas Engineering Solutions, Inc. (Ramboll) under contract to the Clark County Department of Environment and Sustainability (DES), Division of Air Quality (DAQ).

This report comprises the Technical Support Document for the attainment demonstration. Procedures described herein follow the Modeling Protocol (Ramboll, 2022a), developed at the start of this project, and adhere to the most recent photochemical modeling guidance from EPA (2018a). Additional historical context, details and procedural information are provided in the Modeling Protocol.

1.2 Background

The 2015 ozone NAAQS is set at 0.070 parts per million by volume (ppm). The form of the NAAQS is based on quality-assured, certified monitoring data reported as maximum daily 8-hour average (MDA8) ozone concentrations. An area's status relative to the NAAQS is determined by its monitored "design value" (DV), which is defined as the three-year average of the fourth highest MDA8 ozone concentration in each year. The EPA designates areas as nonattainment when DVs exceed the NAAQS. Monitored ozone concentrations are reported as parts per billion by volume (ppb); EPA's convention is to truncate ozone DVs to the nearest whole ppb, so a DV exceeding 70.9 ppb violates the 0.070 ppm ozone NAAQS.

In June 2018, the EPA designated the CCNAA as Marginal based on the maximum 2015-2017 DV of 74 ppb reported among all official monitoring sites within the basin (Federal Register, 2018). The final SIP implementation requirements rule for the 2015 ozone NAAQS was signed by the EPA Administrator on November 7, 2018 (EPA, 2018b). Accordingly, Marginal areas were expected to attain the ozone standard by August 3, 2021 based on their 2018-2020 DV. In July 2022, the EPA reclassified the CCNAA from Marginal to Moderate based on the maximum 2018-2020 DV of 74 ppb. Moderate nonattainment areas are to attain the ozone standard by August 3, 2024 based on their 2021-2023 DV.

The DES/DAQ has submitted "exceptional event" demonstrations to the EPA (e.g., Sonoma Technology, 2021), which show that several ozone exceedance days during 2018 through 2020 were influenced by large wildfires and stratospheric intrusions impacting air quality in the CCNAA. If approved, those specific exceedance days impacted by exceptional events would not count toward the calculation of the area's 2018-2020 DV. However, EPA has indicated that not all exceptional event demonstration days will be approved, and so the revised 2018-2020 DV with the approved exceptional event days excluded will continue to exceed the 2015 ozone NAAQS.

1.2.1 8-Hour Ozone Trends

Figure 1-1 presents the 23-year history of peak 8-hour ozone DVs in Clark County along with the three ozone NAAQS that have been promulgated over the same period. The year 2022 is the most recent year of quality-assured, certified monitoring data reported by the County, while 2020 was the year when attainment of the 2015 ozone NAAQS was required for Marginal nonattainment areas to avoid reclassification to Moderate. Areas of the County have been designated nonattainment for the 1997 and 2015 standards. Over this period, peak ozone levels have decreased, particularly during the recession years of 2008-2011. Since that period, however, ozone has remained fairly constant with small variations caused by interannual variability in summer weather and external uncontrollable factors such as wildfires.

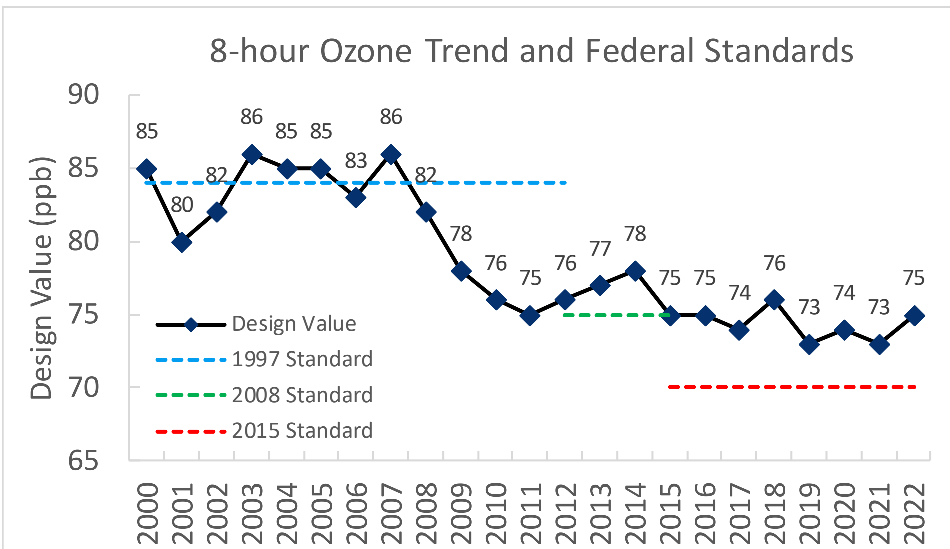


Figure 1-1. History of peak 8-hour ozone design values in Clark County and the three ozone NAAQS that have been in effect since 2000. Data from https://www.epa.gov/air-trends/air-quality-design-values#report.

1.2.2 Recent Ozone Air Quality in Clark County

As of 2022, the DES/DAQ operates 13 ambient ozone monitoring sites in the region, most of which also measure other pollutants and meteorological parameters. Figure 1-2 shows the location of the 14 ozone monitoring sites used in this study that operated in 2016, most of which continue to operate today. DAQ's ambient air monitoring network meets the monitoring requirements for criteria pollutants pursuant to Title 40, Part 58, of the Code of Federal Regulations (CFR), Appendix D (EPA, 2008). The DES/DAQ submits quality-assured monitoring data to the EPA's Air Quality System (AQS). The monitoring sites characterize urban/basin ozone patterns in Las Vegas, as well as air quality upwind and downwind of the LVV. For example, the southern Jean monitoring site along the I-15 corridor generally characterizes transport into the LVV, whereas the Apex and Indian Springs sites to the north characterize outflow from the LVV.

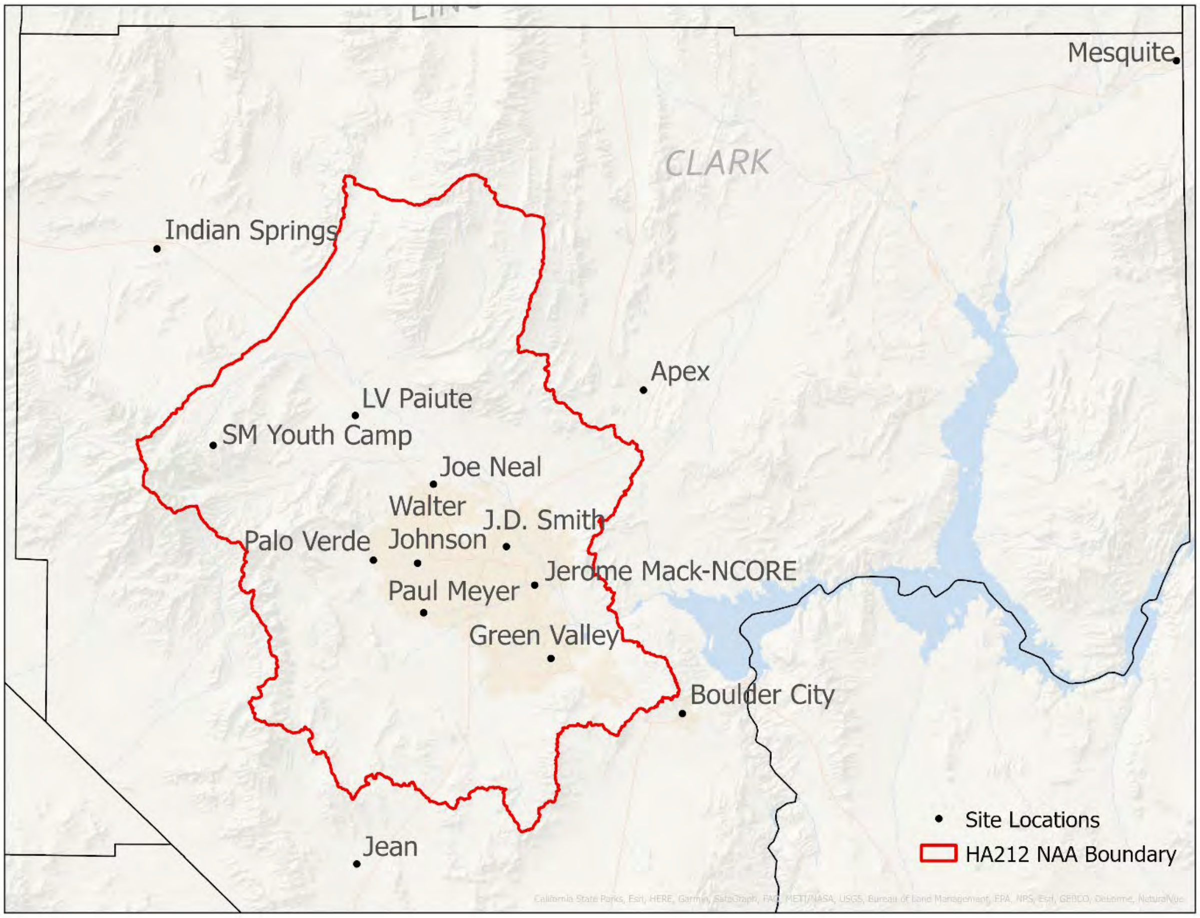


Figure 1-2. Clark County ozone monitoring sites used in this study that operated in 2016 .

Figure 1-3 shows the spatial distribution of 2020 DVs, when attainment was required for Marginal nonattainment areas, at the 10 ozone monitoring sites within and immediately surrounding the CCNAA (sites shown in grey were not official ozone monitors). Sites exceeding the 2015 ozone standard are shown in dark blue and are centered in the LVV and near Henderson. Two sites within the CCNAA, and all other sites outside, did not exceed the standard. The figure indicates the highest ozone levels in the basin occur over a distinct urban-oriented spatial pattern.

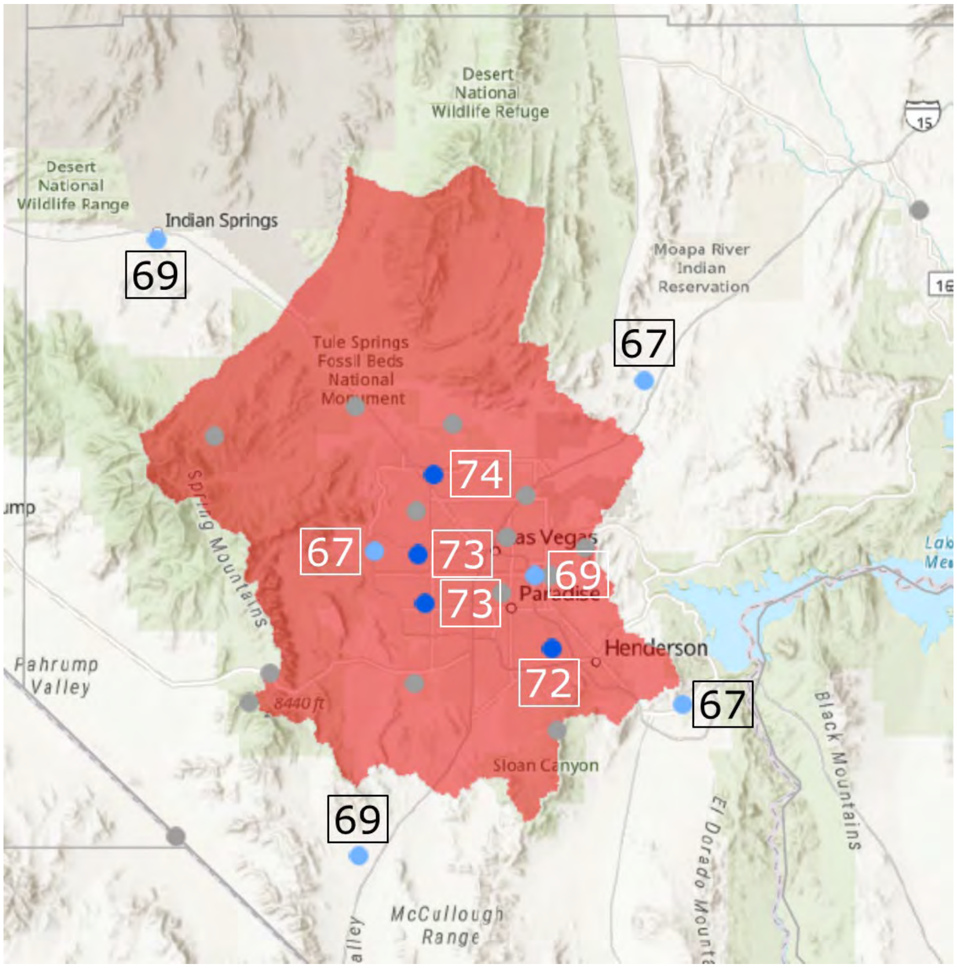


Figure 1-3. Spatial distribution of 2020 design values at 10 ozone monitoring sites within and immediately surrounding the CCNAA, as depicted by orange shading. Sites shown in grey are not official ozone monitors. Background image from https://epa.maps.arcgis.com/apps/MapSeries/index.html?appid=bc6f3a961ea14013afb2e0d0e450b0d1.

1.2.3 Conceptual Model of High Ozone Levels in Clark County

This section is largely based on the summary from Sonoma Technology (2021). Clark County is located in southern Nevada and borders California and Arizona. Clark County includes the Las Vegas – Henderson – Paradise Metropolitan Area, one of the fastest growing metropolitan areas in the United States with a 2020 population of 2.2 million (US Census Bureau, 2020). The LVV consists of a 1,600 km^2 basin that lies between 500-900 m above sea level (Langford et al., 2015). It is surrounded by the Spring Mountains to the west (3,000 m) and the Sheep Mountain Range to the north (2,500 m). Three mountain ranges comprise the southern end of the valley. The valley floor slopes downward from west to east, which influences surface weather and runoff patterns. The I-15 corridor to the southwest is an important atmospheric transport pathway from the Los Angeles Basin into the LVV (Langford et al., 2015).

The LVV experiences abundant sunshine and average summer high temperatures ranging 34 to 40°C (93 to 104°F). The urban heat island effect causes large temperature gradients within the LVV, with generally cooler temperatures on the eastern side. Winds tend to come from the southwest during spring and summer and from the northwest in the fall and winter. The bounding mountain ranges direct basin-wide wind flows while inducing upslope/downslope circulations during weak flow conditions. The altitudes of these ranges are roughly equivalent to the summer daily boundary layer depth, leading to the trapping of pollutants within the basin during stagnant conditions. The surrounding mountains also affect precipitation patterns, contributing to low annual rainfall accumulations of 107 mm (4.2 in), 22% of which occurs during the summer monsoon season in July through September (National Weather Service Forecast Office, 2020).

During the May-September season, ozone concentrations are influenced by the photochemical oxidation of local precursor emissions comprising nitrogen oxides (NOx) and volatile organic compounds (VOC), regional and intercontinental transport into the region, and by exceptional events such as wildfires and stratospheric intrusions (Langford et al., 2015; Clark County, 2019). Local ozone production is maximized during hot, stagnant conditions when strong regional high pressure suppresses boundary layer depth and reduces basin ventilation. Transport from upwind source regions, particularly the Los Angeles Basin, occurs during southwesterly winds, while southerly transport from Mexico dominates later in the season due to the summer monsoon (Langford et al., 2015; Zhang et al., 2020).

Local precursor emissions in Clark County include NOx and VOC from mobile and stationary sources, NOx from natural-gas power generation, and VOC from consumer products and biogenic sources (vegetation). According to the 2017 CCNAA emission inventory developed in this study (Ramboll, 2024b), local anthropogenic sources emit 95 tons of NOx per day and 108 tons of VOC per day during a typical ozone season weekday (Table 1-1). On-road mobile sources comprise 38% of total NOx emissions while total mobile emissions comprise 77% of total NOx emissions during the ozone season. Nonpoint (area) sources contribute 52% of total VOC emissions. Biogenic emissions are not reported here as their estimates range by several orders of magnitude depending on which biogenic emission model is employed (as detailed in Section 8.4.10).

Table 1-1. 2017 CCNAA anthropogenic emissions (TPD) for a typical summer weekday.

Source Category	2017 NOx	2017 VOC
Point source	2.92	1.25
Nonpoint source	6.15	57.72
On-road mobile	37.91	24.81
Non-road mobile	36.98	24.03
Airports (commercial & Federal)	11.90	1.96
Locomotives	0.80	0.04
Total	96.66	109.81

1.2.4 2013 Las Vegas Ozone Study

This summary is extracted from Langford (2014). The 2013 Las Vegas Ozone Study (LVOS) assessed the influences from stratospheric and long-range transport from Asia on surface ozone concentrations in Clark County and determined if these processes contributed to exceedances of the NAAQS. The study also characterized local photochemical production and regional transport from the Los Angeles Basin and impacts from wildland fires. Measurements were made at a former US Air Force radar station ~45 km northwest of Las Vegas on Angel Peak (~2,700 m above sea level) in the Spring Mountains. The study consisted of two extended lidar ozone profiler measurement periods in late May and late June from the surface to ~2,500 m above ground level (~5,200 m above sea level), and continuous in situ measurements of ozone, carbon monoxide, and meteorological parameters at the surface. Measurement activities were guided by forecasts and analyses from the National Oceanic and Atmospheric Administration's (NOAA) FLEXPART particle dispersion model and the Real Time Air Quality Modeling System (RAQMS), while measurement interpretation was aided by the NOAA GFDL-AM3 chemistry-climate model. The 2008 ozone NAAQS was exceeded in Clark County on 6 days during LVOS and analyses showed that stratospheric ozone had major contributions on 4 exceedance days while transported pollution from Asia had smaller contributions on 3 exceedance days. Modeling analyses suggested that wildland fires were partly responsible for 3 exceedance days outside the LVOS measurement period. Thus, results suggested that all 6 exceedance days were influenced by transport from outside the county, and further indicated that stratospheric, Asian, and wildfire contributions will be a greater concern with the lower 2015 NAAQS.

1.2.5 2017 Fires, Asian, and Stratospheric Transport–Las Vegas Ozone Study

The summaries below are extracted from Langford (2022) and Zhang et al (2020). The 2017 Fires, Asian, and Stratospheric Transport–Las Vegas Ozone Study (FAST-LVOS) was a follow-on study of ozone transport to Clark County. The field campaign was conducted from mid-May through June using lidar, ozonesonde, aircraft, and in situ measurements. In conjunction with a variety of models, the study characterized ozone and related species above southern Nevada and California and assessed the influence of stratospheric intrusions, wildfires, Asian transport, as well as local and regional contributions on surface ozone concentrations in the LVV. Campaign measurements (Langford, 2022) found elevated ozone layers above Las Vegas on more than 75% (35 of 45) of the sample days and showed that entrainment of these layers contributed to mean regional background concentrations of 50–55 ppb, or 70-80% of the 2015 ozone NAAQS. The detection and attribution of high background ozone events in the southwest US is challenging but relevant to the 2015 ozone NAAQS and possible lower standards in the future.

Simulations were conducted with two global models (GFDL-AM4 and GEOS-Chem) to study local to global contributions during high ozone events (Zhang et al., 2020). While ozone produced from regional anthropogenic emissions dominate pollution events in the LVV, stratospheric intrusions can elevate surface ozone above 70 ppb. Modeling showed stratospheric influences on 4 out of the 10 days when MDA8 ozone exceeded 65 ppb in Clark County. GFDL-AM4 captured key characteristics of deep stratospheric intrusions consistent with FAST-LVOS profile and surface measurements at Angel Peak, whereas GEOS-Chem did not simulate observed features as well and underestimated surface observations by ~20 ppb. On days when observed MDA8 ozone exceeded 65 ppb and GFDL-AM4 simulated 20–40 ppb stratospheric enhancements, GEOS-Chem simulated ~15 ppb lower background ozone. However, during a wildfire event, GEOS-Chem estimated ~15 ppb more ozone, in better agreement with lidar observations, while at the surface, the two models bracketed observed MDA8 ozone. Both models captured large-scale transport of Asian pollution, but neither could resolve fine-scale pollution plumes sensed by the numerous measurement platforms. US background ozone estimated from the two models differed by 5 ppb on average (greater in GFDL-AM4) and up to 15 ppb episodically.

1.2.6 2021 Field Measurements and Modeling

The NOAA Chemical Sciences Laboratory (CSL) and the Cooperative Institute for Research in Environmental Sciences (CIRES) at the University of Colorado conducted an intensive field measurement campaign during July through September 2021 (NOAA, 2022). The study addressed organic compound emissions and chemistry in Clark County, including: (1) measuring VOC from volatile chemical products (VCP), mobile sources, cooking, and industrial facilities; (2) characterizing their spatial distribution; (3) identifying chemical tracers to apportion VOCs among VCP, energy-related, cooking, and biogenic sources; (4) measuring the composition of gas- and aerosol phase organics in the urban atmosphere; and (5) quantifying anthropogenic nitrogen oxide (NOx = NO + NO_2) emission from mobile sources, buildings, industrial facilities, and outlying agricultural regions and power generation. A comprehensive list of VOC, NOx, ozone and greenhouse gases were measured by the NOAA Mobile Laboratory and at the Jerome Mack site. Atmospheric profiles of winds and aerosol backscatter were measured by LIDAR at the North Las Vegas airport.

Photochemical box modeling representative of conditions at the Jerome Mack monitoring site was conducted using emissions estimated from the field measurements to assess organic gas reactivity and ozone sensitivity to VOC and NOx perturbations. Results indicated that ozone production is more NOx sensitive but within the transition zone where ozone would respond to both NOx and VOC reductions. The authors suggested that "in other regions of Las Vegas, where urban NOx might be larger than at Jerome Mack, ozone production could be NOx saturated."

Three-dimensional photochemical transport modeling was also performed using the Weather Research Forecasting with Chemistry (WRF-Chem) model. Results verified that transported regional/background of ~60 ppb is a significant fraction of MDA8 ozone during high temperature events. Reducing local NOx emissions by 50% can reduce MDA8 ozone by ~10 ppb, which is consistent with box modeling. However, effects from reducing local VOC emissions is mixed and WRF-Chem results are inconsistent with box modeling; biogenic VOC emission estimates were noted as a key uncertainty. Modeling also confirmed that wildfires are potentially a significant source of ozone pollution in Clark County.

While the field study final report has just been completed and the collected data are not directly useable for the photochemical modeling described here, we refer to certain general results from the field study to qualitatively assess modeling conducted for the SIP and to provide information for the weight of evidence.

1.2.7 EPA Modeling Platform

The EPA routinely develops national photochemical modeling platforms (MP) to evaluate air quality impacts of national rules and to conduct transport and contribution assessments. The national MPs typically coincide with the triennial National Emission Inventory (NEI[1]) years (e.g., 2014 and 2017). Below we discuss the EPA's most recent MP.

The EPA and Multi-Jurisdictional Organizations (MJO) conducted an inventory collaborative study[2] to develop a 2016 emissions inventory of comparable quality to the NEI. EPA developed several versions of the 2016 MP based on a continental US modeling domain with 12 km grid resolution (referred to as "12US2") and an expanded North American domain with 36 km resolution ("36US3"). Meteorological inputs were based on a 2016 WRF simulation conducted by EPA (2019a) while initial and boundary conditions (IC/BC) for the 36US3 domain were based on a 2016 hemispheric CMAQ simulation (EPA, 2022a). EPA has released several versions of their 2016 MP:

- 2016v7.1 Alpha[3] (2016fd emissions): available in June 2019 based mainly on 2014 NEIv7.1 emissions.

[1] https://www.epa.gov/air-emissions-inventories/national-emissions-inventory-nei
[2] http://views.cira.colostate.edu/wiki/wiki/10197
[3] https://www.epa.gov/air-emissions-modeling/2016-alpha-platform

- 2016v7.2 Beta (2016ff emissions): updated 2016 emissions from the joint EPA/MJO emissions collaborative study, originally released in March 2019 through the Intermountain West Data Warehouse (IWDW[4]).
- 2016v7.2 Beta Prime (2016fg emissions): EPA made updates for their preliminary 2028 regional haze modeling (EPA, 2019b).
- EPA 2016v1[5] (2016fh emissions): released in November 2019, with several updates made in the following months (EPA, 2021), including emission projections for 2023 and 2028.
- 2016v2[6] (2016fj emissions): uses the same meteorological and IC/BC data as 2016v1 and includes emissions scenarios for 2016, 2023, 2026 and 2032 (EPA, 2022b). EPA applied the MOtor Vehicle Emissions Simulator (MOVES3) for all years to generate Emissions Factor (EF) lookup tables for processing model-ready on-road mobile source emissions. The 2016v2 MP contains several major updates as follows:
  - Use of the MOVES3[7] mobile source emissions model instead of MOVES2014 used in the 2016v1 MP.
  - Updated non-point inventory from the 2017 NEI[8] including a new volatile chemical products (VCP) emissions inventory approach (Seltzer et al., 2021).
  - Updated oil and gas emissions for the western states using data provided by WRAP.
  - Corrections for double counting of emissions at airports.
  - Updated emissions for Canada and Mexico.
  - Updated biogenic emissions using a newer version of the Biogenic Emission Inventory System and the Biogenic Emissions Landuse Database (BEIS3.7/BELD5) instead of BEIS3.61/BELD4 used in the 2016v1 MP.

EPA (2022c) released the 2016v2 MP in January 2022[9]. The 2016v2 MP has been used to project future ozone DVs for the years 2023, 2026 and 2032. EPA estimated that ozone DVs in Clark County may not attain the 2015 ozone NAAQS in 2023 but would attain in 2026 and 2032 (Table 1-2).

EPA also used the 2016v2 MP for the preliminary interstate ozone transport modeling for the 2015 ozone NAAQS (EPA, 2022d), in which 2023 DV contributions were estimated from individual states, foreign sources, fires and biogenic emissions. EPA estimated that California's contribution to ozone DVs in Clark County is roughly as large as Nevada's own contribution, while most ozone is transported into the LVV from BCs (Table 1-3) reflecting total global contributions. Fires and biogenic emissions are estimated to be minor contributors (1-3 ppb) and Canada and Mexico contribute even less (1-2 ppb).

[4] http://views.cira.colostate.edu/iwdw/

[5] https://www.epa.gov/air-emissions-modeling/2016v1-platform

[6] https://www.epa.gov/air-emissions-modeling/2016v2-platform

[7] https://www.epa.gov/moves/latest-version-motor-vehicle-emission-simulator-moves

[8] https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data

[9] https://gaftp.epa.gov/Air/aqmg/2016v2_Platform_Modeling_Data/

Table 1-2. Projected 2023, 2026 and 2032 ozone DVs (ppb) at all Clark County ozone monitoring sites based on EPA's 2016v2 modeling platform (from https://gaftp.epa.gov/Air/aqmg/2016v2_Platform_Modeling_Data/ accessed April 2022).

Site ID	2023fj Avg 3x3	2023fj Max 3x3	2026fj Avg 3x3	2026fj Max 3x3	2032fj Avg 3x3	2032fj Max 3x3
320030022 Apex	66.1	67.7	65.3	66.9	64.4	65.9
320030023 Mesquite	58.3	59.0	57.9	58.5	57.3	58.0
320030043 Paul Meyer	68.5	69.5	67.8	68.7	66.9	67.8
320030071 Walter Johnson	67.7	69.3	66.7	68.3	65.7	67.2
320030073 Palo Verde	67.7	68.4	66.7	67.4	65.7	66.3
320030075 Joe Neal	70.0	71.0	69.0	69.9	67.8	68.7
320030298 Green Valley	66.6	66.6	65.6	65.6	64.4	64.4
320030540 Jerome Mack	65.0	66.3	64.1	65.3	63.1	64.3
320030601 Boulder City	61.8	62.7	61.0	62.0	60.1	61.0
320031019 Jean	64.8	66.4	64.2	65.8	63.6	65.2
320032002 J.D. Smith	67.9	68.4	66.9	67.4	65.7	66.2
320037772 Indian Springs	65.1	65.6	64.6	65.1	63.9	64.4

Table 1-3. Projected 2023 ozone DV contributions (ppb) from Nevada, other states, foreign sources, fires, and biogenic emissions at 10 LVV ozone monitoring sites based on EPA's 2016v2 modeling platform (https://gaftp.epa.gov/Air/aqmg/2016v2_Platform_Modeling_Data/ accessed April 2022).

Site ID	AZ	CA	NV	Canada +Mexico	2023 Fires	IC/BC	Biogenic
320030022 Apex	0.31	6.90	6.58	1.33	1.57	47.03	1.83
320030043 Paul Meyer	0.37	6.96	8.19	1.48	2.30	46.43	1.94
320030071 Walter Johnson	0.19	7.40	6.31	1.31	3.10	46.72	1.70
320030073 Palo Verde	0.19	7.40	6.31	1.31	3.10	46.72	1.70
320030075 Joe Neal	0.21	7.44	8.46	1.28	0.67	49.59	1.75
320030298 Green Valley	0.46	7.60	6.47	1.84	1.77	45.58	1.99
320030540 Jerome Mack	0.42	6.89	8.45	1.73	1.84	42.94	1.86
320031019 Jean	0.13	6.66	0.99	1.61	2.21	51.22	1.42
320032002 J.D. Smith	0.36	7.79	10.57	1.31	0.78	44.48	1.97
320037772 Indian Springs	0.07	5.54	1.66	0.79	1.90	53.25	1.29

2.0 MODEL SELECTION

The model selection process for the CCNAA ozone attainment demonstration followed EPA (2018a) guidance. The EPA recommends that models be selected for ozone SIP studies on a case-by-case basis, yet explicitly mentions the Community Multiscale Air Quality (CMAQ) model and the Comprehensive Air quality Model with extensions (CAMx) as the most commonly used photochemical grid models (PGM) for this purpose. Thus, both satisfy EPA's selection criteria and are preferred over other PGMs. EPA's ozone modeling guidance lists several criteria for model selection that are paraphrased as follows:

- It should not be proprietary.
- It should have received a scientific peer review.
- It should be demonstrated to be applicable to the problem on a theoretical basis.
- It should be used with available data bases that are adequate to support its application.
- It should be shown to have performed well in past modeling applications.
- It should be applied consistently with an established protocol on methods and procedures.
- It should have a user's guide and technical description.
- The availability of advanced features (e.g., probing tools or science algorithms) is desirable.
- When other criteria are satisfied, resource considerations may be important and are a legitimate concern.

For more than a decade, the Clark County DES/DAQ has employed WRF, SMOKE, MOVES, BEIS and CAMx to study ozone air quality in the LVV. Therefore, DAQ staff are very familiar with the operation and performance of each model and so for the CCNAA ozone demonstration the model selection is weighted toward this system of models. Furthermore, the EPA, MJOs, states, and many local air quality agencies have successfully applied these models in other ozone regulatory programs throughout the US.

2.1 Weather Research and Forecasting Model

The Weather Research and Forecasting (WRF) model, Advanced Research WRF (ARW) core, supported the CCNAA attainment demonstration modeling by providing meteorological inputs required by the PGM. WRF is a mesoscale numerical weather prediction system designed to serve both operational forecasting and atmospheric research needs (Skamarock et al., 2019). WRF is flexible and efficient computationally, while offering advanced physics, numerical, and data assimilation capabilities contributed by the research community. It features a software architecture allowing for computational parallelism and system extensibility. WRF is suitable for a broad spectrum of applications across scales ranging from sub-kilometer to thousands of kilometers. The effort to develop WRF has been a collaborative partnership, principally among the National Center for Atmospheric Research (NCAR), the National Oceanic and Atmospheric Administration (NOAA), the National Centers for Environmental Prediction (NCEP) and the Forecast Systems Laboratory (FSL), the Air Force Weather Agency (AFWA), the Naval Research Laboratory, the University of Oklahoma, and the Federal Aviation Administration (FAA).

WRF is publicly available, has full documentation, and possesses two decades of demonstrated success in simulating meteorological conditions and driving PGM simulations throughout the US specifically for regulatory and research air quality studies.

2.2 Emissions Models

2.2.1 Sparse Matrix Operator Kernel Emissions Processing System

The Sparse Matrix Operator Kernel Emissions (SMOKE) processing system prepared emission inputs for the PGM. SMOKE is an efficient, modern tool that generates temporally, spatially, and chemically allocated emission inputs from on- and non-road mobile, point, non-point (area), biogenic, and fire sources (UNC, 2020). Except for mobile and biogenic emissions, which are developed from separate models and processed through SMOKE, its purpose is to convert an existing annual emissions inventory by county and individual point source into the specific formatted emission files required by PGMs. SMOKE performs three main functions for this purpose: (1) spatially allocates county-level emissions to PGM grid cells using a surrogate distribution (e.g., population, land use, etc.); (2) temporally allocates annual emissions to a specific time (e.g., monthly or seasonally, day of week, and hour); and (3) chemically maps criteria pollutant emissions to the individual compounds needed by the PGM chemical mechanism (most important for VOC and particulate matter).

SMOKE is the most current and widely used emissions processor that supports regulatory modeling activities throughout the US. It is designed specifically to translate US NEI datasets to the CMAQ and CAMx models and is flexible to incorporate local and special emissions data. It includes capabilities to directly process mobile source emissions from MOVES and biogenic emissions from BEIS.

2.2.2 MOtor Vehicle Emissions Simulator

The MOtor Vehicle Emissions Simulator version 3 (MOVES3) estimated emission rates from on-road and non-road motor vehicle sources. MOVES3 is EPA's latest mobile source emissions model (EPA, 2020a, 2021a) that estimates emissions at the national, county, and project level for criteria air pollutants, greenhouse gases, and air toxics. Updates from the previous version include:

- The latest data on vehicle populations, travel activity, and emission rates as well as updated fuel supply information at the county level.
- Better accounting for vehicle starts, long-haul truck hoteling, and off-network idling.
- Incorporation of the impacts of the Heavy-Duty Greenhouse Gas Phase 2 rule and the Safer Affordable Fuel-Efficient (SAFE) Vehicles Rule.
- Improved user interface to make the model easier to use and updated for compatibility with newer software.

These updates ensure that MOVES3 is a state-of the-science model and the most accurate tool for estimating emissions from the transportation sector for most purposes. Outside of California, it is the only EPA-approved mobile source emissions model available in the US.

2.2.3 SMOKE-MOVES

The "SMOKE-MOVES" processing stream converted emission factors (EF) generated by MOVES3 to emission inputs required by the PGM. It combines data from several MOVES3 EF look-up tables, vehicle activity (e.g., vehicle miles travelled or VMT), and meteorological data (typically from WRF) to generate hourly, gridded, speciated mobile source emissions input files. SMOKE-MOVES was used in the standard convention by using representative county-level activity data provided by Clark County and EPA (for areas outside of Clark County) to generate on-road mobile source emission inputs.

2.2.4 Biogenic Emission Inventory System

The Biogenic Emission Inventory System (BEIS) estimated natural VOC emissions from vegetation and NOx from soil (EPA, 2022e). Built into SMOKE to specifically support CMAQ, BEIS is driven by ambient meteorology and land cover data from the Biogenic Emissions Landuse Database (BELD). BELD data provide distributions of hundreds of vegetation classes at 1 km resolution over most of North America.

Several versions of BEIS have been developed and applied during the evolution of the EPA 2016 emissions modeling platforms. BEIS3.61/BELD4 was used for the 2016v1 MP. Updates from previous versions included incorporating the US National Land Cover Data (NLCD) into BELD4 and calculating leaf temperature using a canopy model instead of 2-meter temperature directly. BEIS3.7/BELD5 was used for the 2016v2 MP. This version uses updated biomass and emissions factors and several updates to the landuse database. BEIS4/BELD6 is the latest version, released in mid-2022, that includes fundamental updates to the landuse database.

As described in Section 8.4.10, each of these three BEIS versions result in substantially different estimates in biogenic VOC emissions in Clark County. BEIS3.7/BELD5 was initially selected for CCNAA modeling to be consistent with the EPA 2016v2 MP. After review of the PGM performance, additional sensitivity tests using BEIS3.6/BELD4 and BEIS4/BELD6 were conducted and evaluated. We also compared emission estimates from all three versions of BEIS to the latest version of the Model of Emissions of Gases and Aerosols from Nature (MEGAN, version 3.2), developed by the University of California at Irvine (UCI, 2022). MEGAN3.2 includes expanded plant emissions data in western states and the inclusion of vegetative data for urban areas, which were implicitly zero in previous versions and led to zero urban biogenic emissions.

2.3 Comprehensive Air quality Model with extensions

The CAMx photochemical grid model was used for the CCNAA ozone attainment demonstration. CAMx is a state-of-science “one-atmosphere” multi-scale photochemical grid model capable of addressing ozone, particulate matter, toxics, visibility, and acid deposition at regional, urban, and local scales over periods of days to years (Ramboll, 2022b). CAMx is a publicly available open-source computer modeling system built on today’s understanding that air quality issues are complex, interrelated, and reach beyond the urban scale. CAMx is designed to (a) simulate air quality over many temporal and geographic scales, (b) treat a wide variety of inert and chemically active pollutants, (c) provide source-receptor, sensitivity, and process analyses, and (d) be computationally efficient and flexible. CAMx v7.2 is the current version, released in May 2022.

The EPA has approved the use of CAMx for numerous ozone and PM SIPs throughout the US and has used this model to evaluate effects of national rules and regional mitigation strategies, including the Cross-State Air Pollution Rule (CSAPR; EPA, 2021b) and most recently the preliminary interstate ozone transport modeling for the 2015 ozone NAAQS (EPA, 2022d). The 2016v1 and v2 platforms include data inputs that support CAMx applications on EPA’s 36 and 12 km continental grids.

2.4 Final Justification for Model Selection

The modeling system employed to support the CCNAA ozone attainment demonstration satisfies all of EPA’s model selection criteria as follows:

- It should not be proprietary: The WRF, SMOKE, MOVES, BEIS, and CAMx models are all publicly available at no cost and can be downloaded from their respective websites[10,11,12,13].

[10] https://www.mmm.ucar.edu/weather-research-and-forecasting-model
[11] https://www.cmascenter.org/smoke/
[12] https://www.epa.gov/moves
[13] http://www.camx.com/

- It should have received scientific peer review: All the models considered have been published in hundreds of peer-review journal articles. CAMx has been subject to its own peer-review reports and an assessment by EPA that it is suitable for ozone SIP modeling (EPA, 2018a).
- It should be appropriate for the specific application on a theoretical basis: The WRF model was designed to simulate time varying three-dimensional meteorological fields and provides all the meteorological information necessary for ozone modeling. The SMOKE, MOVES and BEIS models provide the hourly gridded speciated emissions information required for ozone modeling. CAMx was designed to include all the processes necessary to simulate ozone formation in the troposphere over multiple scales.
- It should be used with data bases which are available and adequate to support its application: The procedures outlined to develop the 2016 CCNAA modeling platform, as described in later sections, rely on data bases that were purposely developed, or are otherwise entirely adequate, to support the meteorological, emission and photochemical model applications.
- It should be shown to have performed well in past modeling applications: The WRF/SMOKE/CAMx modeling system has a demonstrated record of simulating ozone air quality nationally (EPA platforms), throughout the western US (WRAP platforms), within western US nonattainment areas (Texas, Colorado, Utah, New Mexico, Arizona), and has been applied previously by Clark County.
- It should be applied consistently with an established protocol on methods and procedures: The WRF/SMOKE/CAMx application methodology follows the established procedures in EPA (2018a) guidance and all past modeling applications described above.
- It should have a user's guide and technical description: Each of the models cited include technical descriptions developed by the model authors and procedures for application (see websites in footnotes). CAMx includes an up-to-date and comprehensive user's guide (Ramboll, 2022b) that has a detailed technical description and procedures for application.
- The availability of advanced features (e.g., probing tools or science algorithms) is desirable: CAMx includes advanced Probing Tool features, including Ozone Source Apportionment Technology (OSAT), Decoupled Direct Method (DDM) of sensitivity analysis, Process Analysis (PA), and Reactive Tracers (RTRAC), in addition to advanced core model features (e.g., most up-to-date Carbon Bond photochemistry, and a Plume-in-Grid module).
- When other criteria are satisfied, resource considerations may be important and are a legitimate concern: CAMx is more flexible and computationally efficient than CMAQ, allows two-way nesting, and supports both Message Passing Interface (MPI) and Open Message Passing (OMP) parallel processing.

3.0 EPISODE SELECTION

The CCNAA attainment demonstration modeled May through August 2016 as the "base year" because that period adequately represents recent high ozone conditions in the basin and established 2016 modeling datasets developed and vetted by EPA were readily available. The summer of 2016 was fairly typical of climatology, wildfire activity was present but perhaps not as impactful as more recent years, and routine monitoring data exist for the period. The May-August 2016 satisfied EPA (2018a) ozone modeling guidance for selecting modeling episodes for attainment demonstrations.

3.1 EPA Episode Selection Criteria

EPA's ozone SIP modeling guidance recommends the following criteria, at a minimum, for selecting modeling periods (EPA, 2018a, page 19):

1) Model time periods that are close to the most recently compiled and quality assured NEI.
2) Model time periods when observed concentrations are close to the appropriate base year DV and ensure there are enough days so that the modeled attainment test applied at each monitor is based on multiple days.
3) Model time periods both before and following elevated pollution concentration episodes to ensure the modeling system appropriately characterizes low pollution periods, development of elevated periods, and transition back to low pollution periods through synoptic cycles.
4) Simulate a variety of meteorological conditions conducive to elevated pollutant concentrations and poor air quality.

Items 3 and 4 relate to modeling many "episodes" (i.e., multi-day periods) representing the evolution of diverse meteorological conditions, and thus potentially different source types/regions, that lead to exceedances of the ozone NAAQS in the study area. Consequently, the guidance emphasizes modeling an entire summer ozone season to capture meteorological and emissions variability and to include enough high ozone days for the attainment test. This is now common practice in other ozone nonattainment areas in the western US: e.g., Denver (Ramboll, 2019, 2022c), Phoenix (Maricopa Association of Governments, 2016), and Salt Lake City (in preparation). This approach was also adopted for CCNAA modeling.

Below we further address items 1 and 2 of EPA's episode selection criteria in more detail with respect to supporting the justification for summer 2016 as the CCNAA modeled base year.

3.1.1 National Emissions Inventory and Other Supporting Data

EPA generates comprehensive US emission inventories every 3 years (e.g., 2014, 2017, 2020, etc.), but occasionally develops inventories of the same quality for intermediate years as needed (such as for the 2016 MP). Therefore, selecting a base modeling year that aligns with national inventories was prudent, but other factors were considered including the availability of observed ambient air quality data, meteorology, special study data, and existing model-ready datasets.

The 2017 NEI was most recently updated in January 2021 (EPA, 2021c), while the 2016v2 MP is somewhat more recent (EPA, 2022b) and largely based on the 2017 NEI, but it includes some important updates such as a new VCP VOC inventory. The 2016v2 has been designed for studies focused on criteria air pollutants, includes future year projections for 2023, and has been vetted and applied for EPA's current national modeling studies. Routine air quality and meteorological data are available for both 2016 and 2017 years, so the choice of base year is not dependent on routine data. Special study data are available from the 2017 FAST-LVOS (Langford, 2022; Zhang et al., 2020), which could provide ancillary information for the PGM performance evaluation. Most importantly, given the schedule to complete modeling analyses in time for the ozone SIP submittal in 2023, the 2016v2 MP provided a complete set of US and North American model-ready inputs for the summer of 2016, emissions projections for 2023, and a robust foundational database from which to develop inputs for the local Clark County modeling domain.

3.1.2 Observations Consistent with Base Year DVs

The 2016 ozone season is included within the 3-year DV period (2015-2017) that was used to designate the CCNAA as Marginal under the 2015 ozone NAAQS. From Figure 1-1 (Section 1), the CCNAA DV has not changed much since the 2017 DV of 74 ppb, ranging from 73 ppb to 76 ppb including 74 ppb for the 2020 DV (the Marginal attainment year) and 73 ppb for the 2021 DV. Variations are attributed to interannual meteorological variability, effects from suppressed activity due to COVID-19, and the recent drought-induced increase in massive and prolonged western US wildfires that have been shown to affect ozone levels in the LVV (e.g., Sonoma Technology, 2021, 2023).

Table 3-1 lists MDA8 ozone concentrations recorded each day at each monitoring site operating within Clark County during May through September 2016. Exceedances of the ozone standard occurred on the following 23 days, along with peak MDA8 ozone, number of exceeding sites, and a preliminary assessment of the cause of each exceedance:

- May 14: 72 ppb Single exceedance at SM Youth Camp, not official site
- May 20: 79 ppb Single exceedance at SM Youth Camp, not official site
- June 3: 71 ppb (1 site) Local production
- June 6: 73 ppb (1 site) Local production, transport from southern California
- June 7: 77 ppb (1 site) Local production, transport from southern California
- June 8: 74 ppb (1 site) Local production, transport from southern California
- June 14: 71 ppb Single exceedance at SM Youth Camp, not official site
- June 23: 72 ppb (1 site) Local production
- June 24: 84 ppb (9 sites) Southern California wildfire influence
- June 25: 73 ppb (1 site) Southern California wildfire influence
- June 27: 74 ppb (3 sites) Southern California wildfire influence
- July 1: 75 ppb (3 sites) Local production with high humidity
- July 2: 73 ppb (2 sites) Local production with high humidity
- July 13: 71 ppb (1 site) Local production, transport from southern California
- July 24: 71 ppb (1 site) Southern California wildfire influence
- July 25: 73 ppb (1 site) Southern California wildfire influence
- July 26: 77 ppb (1 site) Southern California wildfire influence
- July 27: 83 ppb (5 sites) Southern California wildfire influence
- July 28: 72 ppb (3 sites) Southern California wildfire influence
- July 29: 75 ppb (2 sites) Southern California wildfire influence
- August 23: 71 ppb (1 site) Southern California wildfire influence
- August 24: 80 ppb (6 sites) Southern California wildfire influence
- August 25: 73 ppb Single exceedance at SM Youth Camp, not official site

The maximum MDA8 ozone on these exceedance days ranged from 71 to 84 ppb, with an average of 75 ppb. No exceedance days occurred during September when ozone concentrations exceeded 55 ppb on only 9 days. Therefore, September was not included in the modeling period. Clark County did not file any exceptional event demonstrations to EPA for the year 2016. The largest number of exceedance days in 2016 occurred at the Joe Neal monitoring site, located northwest of the City of North Las Vegas.

Table 3-1. MDA8 ozone concentrations recorded each day at each monitoring site operating within Clark County during the May-September 2016 ozone season. Values highlighted in orange exceed the 70 ppb ozone standard, and values shaded in yellow are within the 55 to 70 ppb range. The site labelled "SM Youth Camp" is not an official AQS monitoring site.

Monitoring Site	May 2016																														
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
Apex	48	50	56	62	51	51	48	57	56	60	51	57	61	57	60	49	51	46	61	67	59	55	59	54	60	60	61	64	66	60	52
Mesquite	43	47	47	55	46	51	47	50	51	50	48	50	53	42	55	44	40	45	58	56	55	50	56	52	50	55	49	54	57	53	45
Paul Meyer	51	52	57	59	49	47	47	51	51	63	55	60	61	59	56	49	52	45	61	64	52	53	56	51	60	55	53	63	60	65	51
Walter Johnson	49	51	57	58	48	48	47	50	51	65	53	60	61	59	57	48	52	44	60	64	51	52	57	51	60	55	56	64	64	65	52
Palo Verde	45	49	55	56	48	46	45	49	51	62	50	58	58	61	55	46	47	41	61	64	50	50	57	50	60	50	51	63	62	62	50
Joe Neal	48	51	58	61	50	50	53	52	54	67	53	64	62	58	55	49	54	44	62	65	53	51	59	51	62	55	61	66	68	63	52
Green Valley	46	48	52	57	50	42	47	50	50	58	49	57	56	56	55	49	48	46	59	61	52	54	57	52	58	59	54	62	61	62	57
Jerome Mack	49	50	54	58	49	46	48	52	51	62	50	61	57	53	58	48	50	46	59	62	53	56	57	NV	57	59	58	63	63	63	57
Boulder City	46	48	53	57	47	46	48	52	52	57	49	56	55	55	56	52	54	45	58	62	59	52	57	53	57	61	53	60	57	58	51
Jean	52	53	57	57	49	49	51	52	53	58	58	58	58	57	53	48	54	48	62	65	53	48	58	53	59	56	52	62	61	62	60
JD Smith	49	50	55	58	49	46	49	51	51	63	51	61	59	55	58	47	51	44	60	64	54	55	57	50	58	57	60	64	65	64	54
SM Youth Camp	50	53	60	61	56	51	52	52	55	NV	50	65	68	72	57	49	49	47	62	79	61	50	59	56	62	50	54	64	65	59	52
Indian Springs	44	48	54	60	49	50	49	51	49	50	47	57	62	57	51	48	51	39	59	68	51	44	57	51	63	46	51	61	64	54	46
Maximum Value	52	53	58	62	51	51	53	57	56	67	58	64	62	61	60	52	54	48	62	68	59	56	59	54	63	61	61	66	68	65	60

Monitoring Site	June 2016																													
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Apex	54	62	67	59	65	66	66	61	49	41	50	43	55	63	58	57	54	58	57	59	62	58	65	84	64	66	57	55	66	51
Mesquite	NA	NA	NA	NA	NA	56	58	58	51	43	42	40	47	55	56	48	43	51	45	44	52	50	55	71	56	54	48	51	53	53
Paul Meyer	59	64	67	64	63	64	69	68	51	51	53	39	47	62	50	55	48	52	56	60	62	58	64	73	68	67	70	63	64	48
Walter Johnson	54	63	66	63	62	65	70	68	47	52	52	40	47	62	52	57	47	53	60	60	62	58	66	73	69	67	71	60	65	51
Palo Verde	53	60	67	65	62	64	69	70	49	50	50	39	49	66	49	57	49	50	56	58	59	56	63	71	67	66	72	58	62	51
Joe Neal	54	65	71	65	68	73	77	74	48	52	52	42	49	62	52	59	47	55	62	61	64	64	72	83	73	70	74	58	68	56
Green Valley	61	60	63	59	68	64	68	66	49	45	47	42	48	61	54	57	56	50	57	56	57	57	62	73	66	65	62	58	66	50
Jerome Mack	58	62	63	58	68	67	67	64	50	47	48	41	49	59	50	53	52	54	57	58	57	58	64	77	67	63	61	56	67	50
Boulder City	58	53	59	53	60	60	62	58	44	41	44	39	49	55	58	48	52	56	49	56	53	54	59	68	59	58	55	55	59	55
Jean	52	57	63	59	63	62	64	65	54	50	44	38	46	62	50	55	51	48	45	51	57	58	60	68	63	62	65	59	60	54
JD Smith	55	63	66	61	68	70	70	67	55	50	51	41	48	62	53	54	50	54	58	60	59	60	65	78	70	66	65	58	67	51
SM Youth Camp	49	59	72	64	61	61	67	64	46	47	47	42	54	71	53	53	49	52	52	54	59	54	60	70	69	65	69	53	58	57
Indian Springs	48	53	56	61	61	59	55	67	44	49	44	42	44	65	44	56	51	54	46	50	55	58	67	68	58	63	61	52	55	57
Maximum Value	61	65	71	65	68	73	77	74	54	52	53	43	55	66	58	59	56	58	62	61	64	64	72	84	73	70	74	63	68	57

Monitoring Site	July 2016																														
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
Apex	64	64	57	56	66	65	61	63	57	57	56	68	69	65	64	68	59	NV	52	51	52	63	61	48	65	63	62	67	64	60	56
Mesquite	53	57	49	47	51	58	54	50	54	55	49	56	58	49	NV	57	48	39	42	42	43	49	54	55	56	52	53	54	53	55	52
Paul Meyer	70	69	54	53	63	61	66	58	51	56	58	59	65	65	66	66	60	46	44	44	52	NA	NA	NA	NA	NV	76	63	75	59	55
Walter Johnson	74	71	57	52	61	58	66	57	51	56	59	NV	66	67	62	64	62	44	44	45	54	53	67	69	65	69	77	70	71	59	56
Palo Verde	73	70	53	52	62	58	63	55	53	49	57	59	68	66	62	64	59	49	46	43	54	53	64	69	67	68	74	65	67	54	54
Joe Neal	75	73	59	54	62	58	70	60	50	55	66	63	71	70	67	66	60	47	46	48	58	60	69	71	69	77	83	72	69	62	58
Green Valley	63	61	53	52	64	61	61	62	53	59	52	64	60	59	64	65	62	49	48	45	NV	NV	64	57	63	57	64	67	63	57	55
Jerome Mack	NV	63	56	54	63	61	66	63	52	54	56	64	64	62	63	65	62	50	50	49	54	59	67	61	65	64	69	71	67	57	55
Boulder City	59	57	45	52	56	58	51	53	55	60	53	63	58	58	60	60	53	38	44	43	47	54	55	42	57	52	55	55	60	58	54
Jean	59	59	51	52	63	63	63	59	50	59	54	NV	63	65	66	65	61	49	49	45	47	53	60	68	64	57	58	59	61	57	58
JD Smith	67	65	56	53	62	60	67	62	51	56	NV	61	66	63	62	63	60	49	47	47	54	55	66	64	65	66	75	73	70	57	55
SM Youth Camp	57	61	52	57	55	NV	65	59	50	55	59	61	65	66	63	65	62	51	50	48	50	52	61	67	69	69	64	58	61	57	60
Indian Springs	66	62	51	53	59	60	65	56	49	55	39	62	69	67	63	61	53	46	47	49	54	50	57	69	73	58	61	56	55	53	55
Maximum Value	75	73	59	56	66	65	70	63	57	60	66	68	71	70	67	68	62	50	52	51	58	63	69	71	73	77	83	72	75	62	58

Table 3-1 (concluded).

Monitoring Site	August 2016																														
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
Apex	54	57	NA	NA	NV	42	58	62	53	49	50	60	58	59	55	63	58	54	61	61	50	55	57	68	67	44	50	50	50	47	52
Mesquite	51	56	47	55	58	40	46	55	45	36	43	48	52	NA	NV	41	38	39	40	40	40	38	39	43	44	34	35	36	34	32	37
Paul Meyer	55	61	49	55	63	49	58	57	60	59	54	62	70	62	53	64	57	54	53	60	50	58	66	71	68	47	57	64	66	55	53
Walter Johnson	56	63	53	54	65	48	58	57	60	56	52	66	70	63	53	64	59	54	54	64	52	59	56	76	67	49	57	64	63	53	53
Palo Verde	56	65	54	56	65	49	58	57	60	63	55	65	68	63	53	65	62	54	55	64	53	60	67	73	66	48	56	64	60	51	52
Joe Neal	60	65	57	59	67	51	60	59	61	54	55	65	67	64	53	65	63	59	57	68	54	64	71	80	67	52	56	55	61	53	56
Green Valley	50	54	NV	50	59	44	56	58	54	50	49	60	62	61	52	61	56	50	52	57	50	53	60	69	64	46	51	50	54	49	50
Jerome Mack	50	57	47	54	62	44	58	60	57	48	51	67	65	62	54	64	59	53	58	62	52	55	61	75	67	46	53	53	59	51	53
Boulder City	47	54	49	56	59	41	53	57	47	39	40	56	57	55	54	60	53	49	54	54	49	53	60	64	59	47	52	50	50	50	49
Jean	50	51	51	61	59	46	57	58	59	52	54	49	58	57	56	NA	NA	NV	53	58	51	55	57	60	66	47	51	54	50	47	52
JD Smith	51	57	48	52	62	45	57	59	57	48	52	66	64	61	51	62	58	53	56	63	52	57	62	79	63	46	53	53	57	49	54
SM Youth Camp	61	59	55	60	62	57	59	63	66	63	62	57	65	62	63	66	68	59	57	59	53	55	57	67	73	66	57	55	55	53	59
Indian Springs	61	58	54	56	65	52	57	58	61	58	57	54	52	56	57	64	59	55	52	57	53	58	65	55	66	56	57	51	46	48	53
Maximum Value	61	65	57	61	67	52	60	62	61	63	57	67	70	64	57	65	63	59	61	68	54	64	71	80	68	56	57	64	66	55	56

Monitoring Site	September 2016																													
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Apex	50	46	49	47	47	59	45	53	51	44	49	58	48	51	46	45	48	49	44	31	32	49	41	41	46	46	45	41	45	45
Mesquite	35	31	34	34	30	38	29	35	34	31	35	39	33	33	34	33	34	34	30	24	21	34	29	29	34	33	33	29	29	28
Paul Meyer	53	49	47	49	54	58	43	59	63	51	45	55	46	52	51	51	55	51	44	33	35	48	41	41	46	47	46	52	52	56
Walter Johnson	53	49	46	50	55	59	44	60	67	54	48	56	47	56	53	51	54	52	45	33	36	48	40	42	46	47	48	50	49	50
Palo Verde	51	49	49	52	54	56	46	59	64	49	50	57	47	53	51	48	53	53	46	32	34	47	40	43	46	46	47	48	46	49
Joe Neal	55	50	46	50	55	62	50	64	63	56	48	56	46	56	53	52	54	57	48	34	37	48	40	41	46	48	47	50	52	53
Green Valley	47	46	49	47	51	57	38	55	58	48	47	55	48	52	48	46	51	52	40	31	31	47	40	40	45	42	44	48	47	46
Jerome Mack	50	50	48	47	51	58	41	57	59	49	48	56	47	54	52	49	53	52	42	32	32	47	40	42	46	45	46	49	47	48
Boulder City	46	43	48	47	50	56	38	50	55	44	48	53	48	50	48	45	48	48	39	32	31	NA	NA	40	45	45	43	46	45	43
Jean	53	50	49	50	52	58	39	55	63	43	46	58	49	50	50	50	49	45	41	35	38	48	38	44	47	49	46	45	48	52
JD Smith	52	51	47	48	52	60	43	59	60	52	48	54	47	55	52	48	53	53	44	32	34	47	38	43	46	46	46	49	49	49
SM Youth Camp	56	54	54	55	58	60	59	68	62	52	61	62	58	46	47	47	49	59	47	38	51	52	50	48	48	50	49	53	55	60
Indian Springs	53	46	48	47	54	61	55	55	45	44	46	58	48	44	42	41	44	46	48	37	41	49	40	39	42	43	46	46	49	53
Maximum Value	55	50	49	52	55	62	55	64	67	56	50	58	49	56	53	52	55	57	48	37	41	49	41	44	47	49	48	52	52	56

3.1.3 Additional Rationale for Selecting 2016 as the Base Year

The choice to model 2016 satisfied all of the criteria listed in EPA's modeling guidance, most importantly:

1. The average MDA8 ozone over 2016 exceedance days (75 ppb) was close to the 2015-2017 DV (74 ppb) used to classify Clark County as a Marginal NAA, and to the 2018-2020 DV (also 74 ppb) that resulted in the reclassification to Moderate;
2. EPA-vetted emission inventories and modeling datasets were readily available – it was critically important to leverage existing datasets as much as possible given the very tight schedule for the ozone SIP.

There were other reasons why more recent years were not especially suited to represent the base year. Figure 3-1 shows time series of MDA8 ozone at Joe Neal spanning the years 2015 through 2020. There were 17 exceedance days at this site in 2016, although the three highest exceedances were influenced by regional wildfires. There were 13 exceedance days at this site in 2017, 10 in 2018, 1 in 2019, and 9 in 2020. Therefore, 2016 contained the largest number of exceedance days at the peak monitoring site, while 2017 contained the second most. With consistent DVs year-to-year, choosing a different modeled base year should not materially affect the 2023 DV projection.

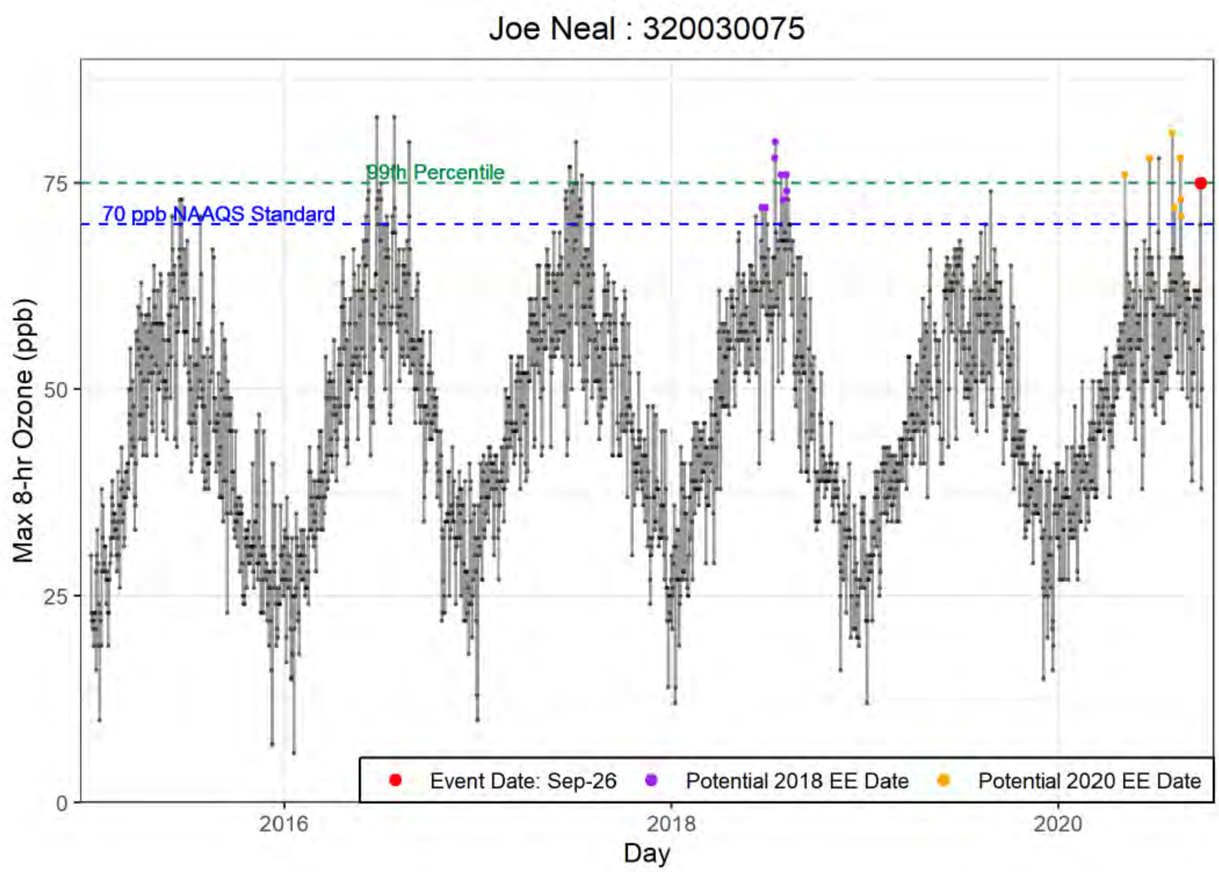


Figure 3-1. Time series of MDA8 ozone at the Joe Neal monitoring site from 2015 through 2020 (figure taken from Sonoma Technology, 2021).

Probably the biggest disadvantage of adopting a more recent year since 2017 was the dramatic increase in exceptional event-like days. Most exceedance days in 2018 and 2020 were associated with plausible wildfire exceptional events, as highlighted in Figure 3-1 (Sonoma Technology, 2021). It is important to maximize the number of high ozone days in the SIP modeling that result from local and regional anthropogenic emissions rather than wildfires. From 2017 through 2021 the western US has burned nearly continuously during the ozone season, and it is increasingly difficult to identify a period when poor air quality in Clark County is not influenced by massive regional fires. While there were potential fire influences on many ozone exceedance days in 2016, more days are believed to be influenced by "typical" local and/or regional anthropogenic emissions than in recent years.

3.2 Analysis of Regional Meteorological and Air Quality Conditions

We analyzed meteorology and air quality over the western US to evaluate the suitability of the 2016 ozone season for modeling by ensuring it represents typical conditions. The following summary is taken from the Denver ozone modeling protocol (Ramboll, 2019); see Appendix A of that document for additional details from Ramboll's extensive analysis. Our findings should be considered in the context of larger climate change trends and their influences on the current western US "mega-drought".

The Regional Technical Operations Working Group (RTOWG) of the Western Regional Air Partnership (WRAP) evaluated the representativeness of several recent years (2014, 2015 and 2016) for their updated annual western regional photochemical modeling platform (Stoeckenius et al., 2018). Ramboll (2019) extended the analysis to include 2017. The RTOWG study noted that for regional air quality planning:

“As significant resources are required to develop and exercise an annual air quality modeling platform for analysis of the issues of concern (primarily ground-level ozone, particulate matter, regional haze, and nitrogen deposition), it is important to establish the “degree of representativeness”, or the degree of difference between calendar base year(s) selected for simulation and analysis….the objective of this study is to compare and contrast the key characteristics of each year analyzed both with respect to each other and with respect to long-term averages”

The key characteristics analyzed included: meteorology (e.g., 500 hPa heights, hydrology, surface temperatures); wildfires; emissions (EGUs and on-road); and air quality (visibility, nitrogen deposition, ozone, and PM). The RTOWG study considered a large area of interest covering the entire western US.

Seasonal and regional variations led Stoeckenius et al. (2018) to conclude that each year exhibits its own unique features. For certain key characteristics analyzed, specific years were shown to exhibit specific issues. For example, 2015 exhibited severe drought conditions west of Rockies and significant fire activity in western Canada and northwest US that impacted regional air quality. Moreover, a significant increase in 2017 wildfires resulted in even larger impacts on air quality throughout the western US. The number of acres burned by western US wildfires in 2016 was approximately half that of 2017 and slightly less than 2015.

For many other characteristics, however, neither 2016 nor 2017 exhibited particularly anomalous conditions. Nevada state-wide precipitation was slightly above average for the 12 months ending August 2016, whereas it was much above average for the 12-month period ending in August 2017. Nevada June-August 2016 average temperatures were much above average, which was weighted by the warmest temperatures in June while above average temperatures occurred during July and August. In contrast, June-August 2017 average temperatures were classified as “record warmest.” Between May and September 2016, the Palmer drought index fluctuated between neutral (3 months) and moderate (2 months) in southern Nevada. The drought index remained neutral throughout summer 2017.

3.3 Future Year to be Modeled

The CCNAA is currently classified as a Moderate Nonattainment Area under the 2015 ozone NAAQS because 2018-2020 ozone DVs failed to attain the standard by the August 3, 2021 attainment date for Marginal areas (Figures 1-1 and 1-3). Moderate areas must attain the NAAQS by August 3, 2024 based on the 2021-2023 DV, or risk further bump-up to Serious. Thus, attainment demonstration modeling was conducted for the 2023 future year. The 2016v2 MP includes projected national emission inventories for the 2023 year. Following EPA (2018a) guidance, CAMx modeling of May-August 2023 included the projected emissions but continued to use all other model inputs (meteorology, boundary conditions, etc.) from the 2016 base year to isolate the impacts from emission changes. Details on future year modeling procedures are presented in other sections of this report.

4.0 MODELING DOMAIN

This section describes the modeling domain and defines the PGM horizontal and vertical grid structures for the CCNAA ozone attainment demonstration modeling. Details include the map projection, domain coverage, grid resolution and grid nesting arrangement.

4.1 Horizontal Grids

The CCNAA attainment demonstration modeling employed the same nested 36/12 km grids as the EPA 2016 MP (36US3, 12US2). A third grid with 4 km grid resolution covering Clark County (CC4c2) was nested within the 12US2 grid. Figure 4-1 displays the 36US3/12US2/CC4c2 domain structure and Figure 4-2 shows the coverage of the CC4c2 grid in greater detail. The cartesian modeling domain is defined on a Lambert Conic Conformal map projection based on the parameters listed in Table 4-1. Specific coordinate and resolution information about each grid is listed in Table 4-2.

Table 4-1. Map projection parameters for the CCNAA 36US3/12US2/CC4c2 modeling domain.

Parameter	Value
Map Projection	Lambert Conic Conformal Perfect sphere, diameter 6370 km
True Latitude 1	33°N
True Latitude 2	45°N
Central Longitude	97°W
Central Latitude	40°N

Table 4-2. Coordinate and resolution parameters for each of the CCNAA modeling grids.

Parameter	36US3	12US2	CC4c2
Grid Cell Size	36 km	12 km	4 km
Total Grid Cells	172 x 148	396 x 246	50 x 62 (w/ buffer) 48 x 60 (no buffer)
SW Corner (km)	-2952, -2772	-2412, -1620	-1696, -412 (w/ buffer) -1692, -408 (no buffer)
NE Corner (km)	3240, 2556	2320, 1332	-1496, -164 (w/ buffer) -1500, -168 (no buffer)
Parent Grid X-Range	N/A	N/A (1-way nested in 36US3)	61 – 76 (in 12US2)
Parent Grid Y-Range	N/A	N/A (1-way nested in 36US3)	102 – 121 (in 12US2)
WRFCAMx I/J Offset	N/A	N/A	183, 87

The CC4c2 grid employed a horizontal resolution that EPA recommends for urban-scale PGM applications so that local influences and details in emissions, chemistry and transport throughout the basin are appropriately resolved. The 12US2 grid provides an adequate mid-level resolution to account for regional sources and transport into Clark County, particularly from California, northern Mexico and neighboring states. The 36US3 grid covers a larger expanse of Canada, Mexico, and the Pacific Ocean, and provides the mechanism by which domain BCs quantify pollutant influx into North America from around the globe.

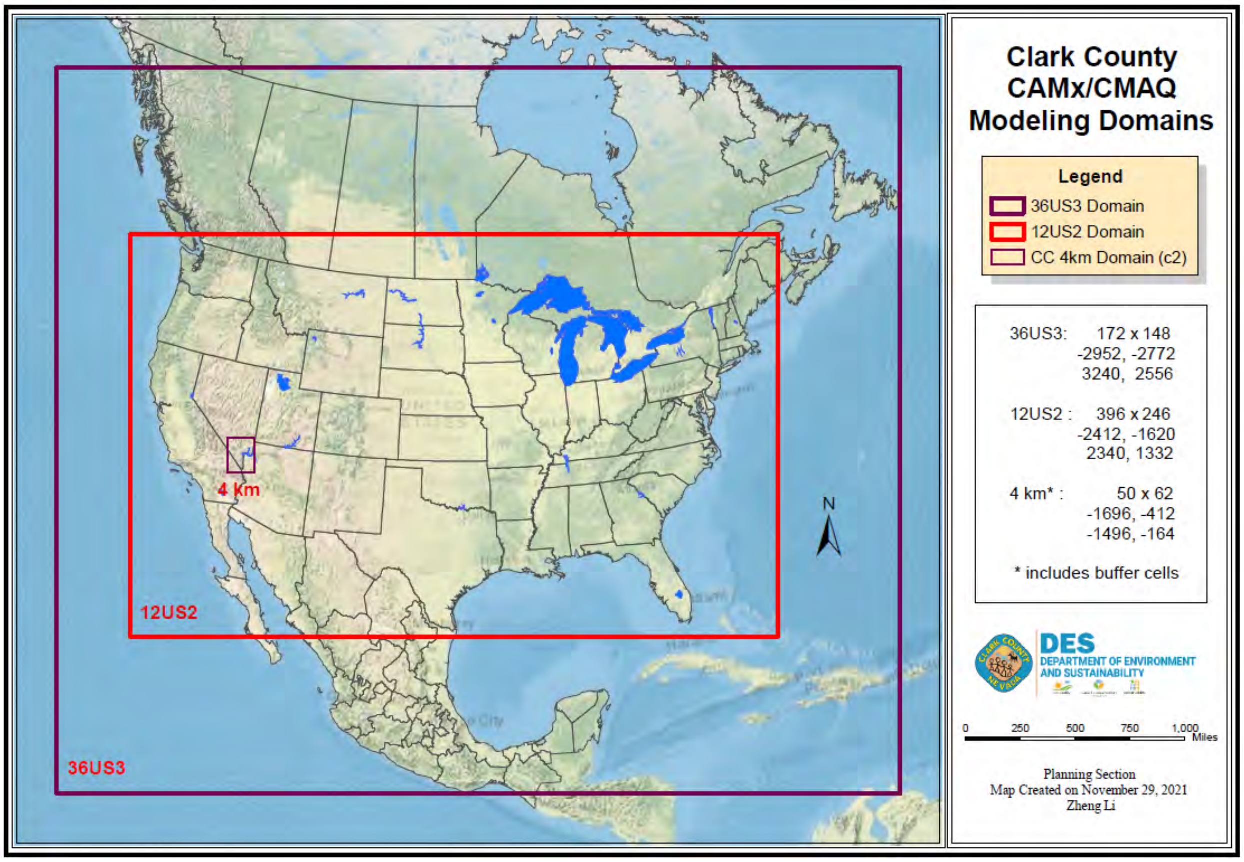


Figure 4-1. PGM nested modeling grids employed for the Clark County ozone attainment demonstration. Details on grid coordinates and number of grid cells are shown in the right inset.

For all CAMx applications, including base year model performance, sensitivity testing, and future year emission reduction scenarios, the 12US2/CC4c2 grids were run together using two-way interactive grid nesting. In initial 2016 base year runs, 12US2 BCs were taken from the 2016v2 MP, which in turn were based on EPA's 2016 CAMx run on the 36US3 grid. EPA developed global BC inputs for the 36US3 grid from their 2016 hemispheric CMAQ simulations (EPA, 2022a). In later and final 2016 base year runs, we derived a new set of 36US3 BCs from an alternative source of global modeling, re-ran the 36US3 grid in CAMx, and extracted new 12US2 BCs for the 12/4 nested runs. Details on the source of global BCs and modeling procedures are provided in Sections 7.4 and 8.4.

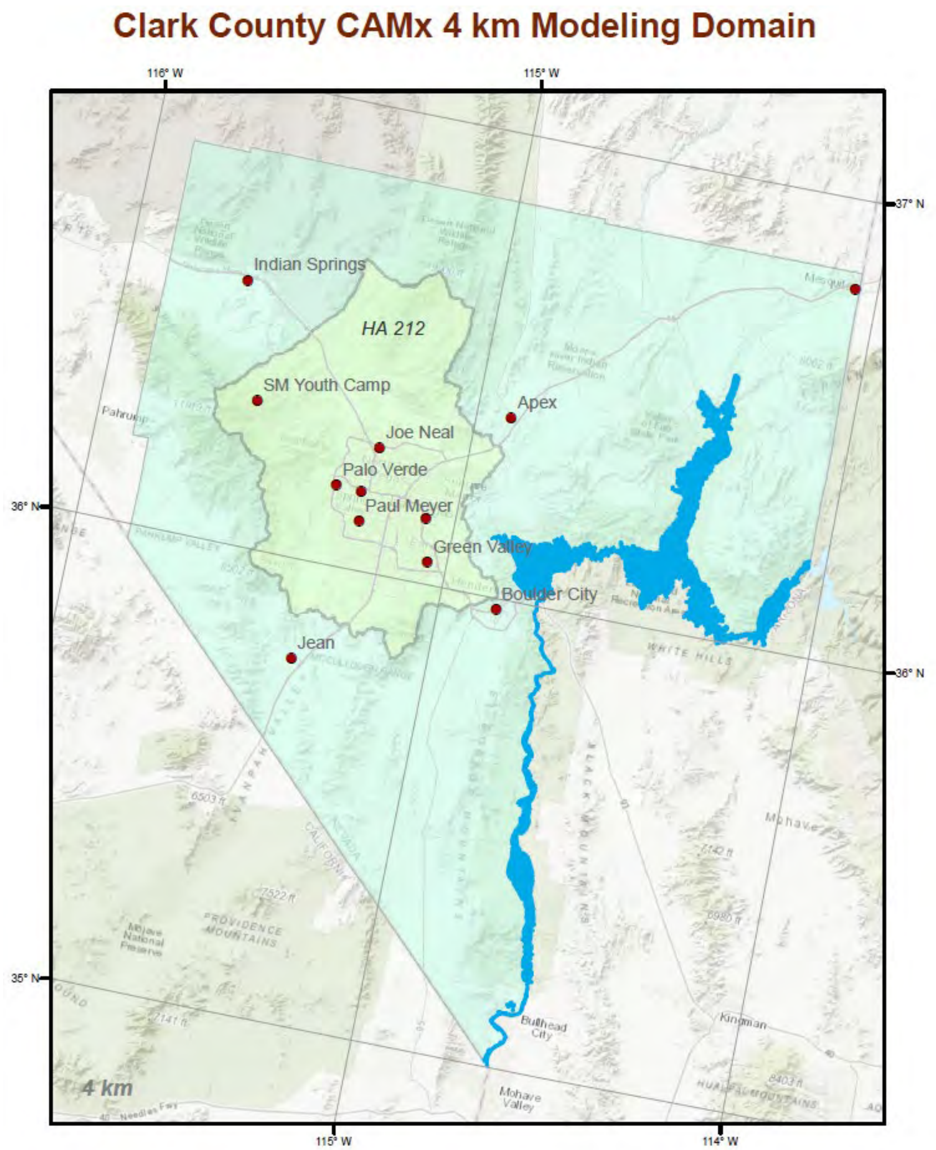


Figure 4-2. Extent of the 4 km Clark County PGM nested modeling grid (CC4c2) employed for the Clark County ozone attainment demonstration. Clark County is shaded in green while the extent of the CCNAA (labeled HA 212) comprises a smaller area of the County. The locations of 12 ozone monitoring sites are also shown for reference.

4.2 Vertical Grid Structure

The vertical grid structure used for CCNAA modeling was entirely defined by the three-dimensional datasets developed for the EPA 2016v2 MP, which in turn was based on EPA's WRF simulations developed to drive the PGM system. The WRF vertical grid comprises 35 layers extending from the surface to ~20 km (50 mb pressure altitude), as shown in Table 4-3. To remain consistent with EPA's grid system, CCNAA modeling maintained the full 35 layer structure for CAMx. The layer structure includes a 20 m deep surface layer, four layers through the lowest 100 m, 14 layers through the lowest 1000 m, and 31 layers within the troposphere (~10 km).

Table 4-3. Vertical grid structure for the EPA 2016 MP.

EPA WRF/CAMx			
Layer	eta	Pressure (mb)	Height (m)
35	0.00	50	20576
34	0.05	98	16297
33	0.10	146	13766
32	0.15	194	11961
31	0.20	243	10555
30	0.25	291	9372
29	0.30	339	8337
28	0.35	387	7416
27	0.40	435	6583
26	0.45	483	5822
25	0.50	532	5120
24	0.55	580	4467
23	0.60	628	3857
22	0.65	676	3284
21	0.70	724	2743
20	0.74	763	2331
19	0.77	792	2033
18	0.80	821	1744
17	0.82	840	1555
16	0.84	859	1370
15	0.86	878	1188
14	0.88	898	1010
13	0.90	917	835
12	0.91	927	748
11	0.92	936	662
10	0.93	946	577
9	0.94	955	493
8	0.95	965	409
7	0.96	975	326
6	0.97	984	243
5	0.98	994	162
4	0.985	999	121
3	0.990	1004	81
2	0.995	1008	40
1	0.9975	1011	20
0	1.0000	1013	0

5.0 BASE YEAR METEOROLOGICAL INPUTS

Ramboll utilized existing CAMx-ready meteorological modeling datasets for the 36US3 and 12US2 grids developed by EPA for their 2016 MP (EPA, 2019). Here, we describe the meteorological modeling and performance assessment for the nested CC4c2 domain covering Clark County as defined in Section 4.

Meteorological inputs for the CC4c2 domain were developed primarily from 2016 WRF simulations recently conducted by EPA on a large grid with 4 km grid spacing covering California and most of Nevada including Clark County (Figure 5-1). EPA applied the same science configuration, inputs, and application methodology as their 12US2 WRFv3.8 simulations that support their 2016 MP (EPA, 2019). The vertical grid structure for the California/Nevada WRF domain is identical to the 2016 MP (Table 4-3) and the horizontal grid aligns with the 12US2 grid with sufficient extent to fully include the CC4c2 CAMx grid. The eastern edge of the WRF grid is 24 km from the eastern edge of the CC4c2 grid, which is beyond the recommended 5 grid point buffer recommended in EPA's guidance. Furthermore, EPA used their 12US2 WRF output to drive WRF 4 km boundary conditions (a process referred to as "nest-down"), which maximizes consistency among wind and mass fields thereby reducing numerical artifacts at the boundaries. Details on the EPA WRF configuration are listed in Table 5-1.

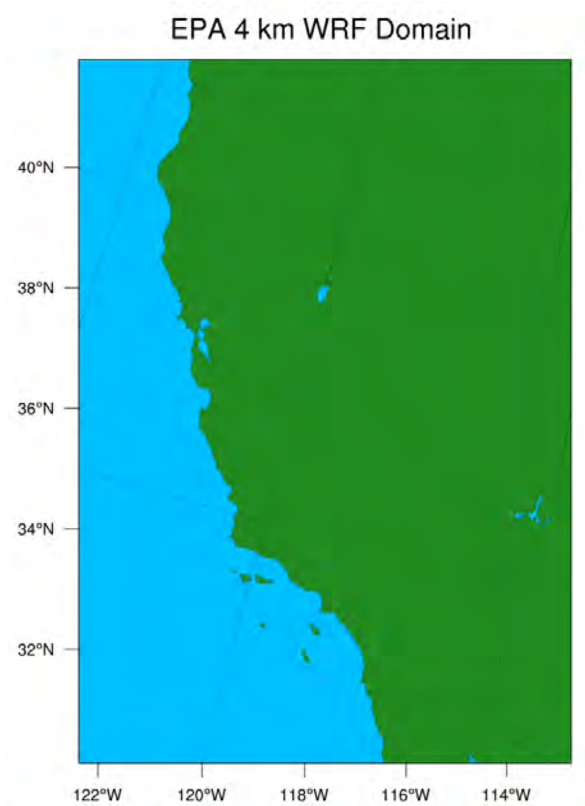


Figure 5-1. Extent of the EPA 4 km WRF domain covering California and Nevada. The domain meshes with the 2016 MP 12US2 grid and sufficiently covers the area of the CC4c2 grid.

Table 5-1. WRF configurations for the EPA and Ramboll 4 km California/Nevada meteorological modeling. The EPA configuration is taken from the 2016 MP 12US grid application. Ramboll's deviations from EPA's configuration are highlighted in red.

Model Component	EPA	Ramboll
Model Code	WRF v3.8	WRF v4.4
Modeling Period	January 1 – December 31, 2016	June 29 – July 4, 2016
Application	Continuous 365 day run	Single 5-day segment
Horizontal Grid		
Map Projection	Lambert Conic Conformal	Lambert Conic Conformal
Projection Center	-97°N / 40°W	-97°N / 40°W
True Latitudes	33°N and 45°N	33°N and 45°N
Grid Points	237 x 339	237 x 339
SW Corner coordinate	-2424, -756	-2424, -756
NE Corner coordinate	-1476, 600	-1476, 600
Vertical Grid		
Layers	35 up to 50 mb (~20 km)	35 up to 50 mb (~20 km)
Coordinate	Sigma (normalized pressure)	Sigma (normalized pressure)
Initial/Boundary Conditions	Nest-down from EPA 12US2 output	12 km North American Model (NAM)
Nudging Analyses	12 km North American Model (NAM)	12 km North American Model (NAM)
Landcover	40-category National Landcover Dataset (NLCD)	40-category National Landcover Dataset (NLCD)
Sea Surface Temperature	1 km Group for High Resolution Sea Surface Temperatures (GHRSST)	0.1 degree Fleet Numerical Meteorology and Oceanography Center Sea Surface Temperatures (FNMOC SST)
Lightning Data	National Lightning Detection Network (NLDN)	None
Physics		
Short/Longwave Radiation	Rapid Radiation Transfer Model - Global (RRTMG)	Rapid Radiation Transfer Model - Global (RRTMG)
Resolved Clouds	Morrison microphysics	Thompson microphysics
Surface Model	Pleim-Xiu (P-X)	Noah
Surface Layer	Pleim-Xiu (P-X)	MM5 Similarity
Boundary Layer	Asymmetric Convective Model (ACM2)	Yonsei University (YSU)
Sub-grid Clouds	Kain-Fritsch	Multiscale Kain-Fritsch or no sub-grid cumulus scheme
Data Assimilation/Nudging		
3-D Wind	1×10^{-4} s^{-1} (above PBL)	1×10^{-4} s^{-1} (all layers)
3-D Temperature	1×10^{-4} s^{-1} (above PBL)	1×10^{-4} s^{-1} (above PBL)
3-D Moisture	1×10^{-5} s^{-1} (above PBL)	1×10^{-5} s^{-1} (above PBL)
Surface Analysis Nudging	None	None
Observation Nudging	None	None
Soil Nudging	P-X temperature & moisture	None
Lightning Assimilation	On (controls deep convection)	None (not available in v4.4)

The Clark County DES/DAQ obtained EPA's WRF output files and ran the Atmospheric Model Evaluation Tool (AMET; EPA, 2022f) to generate a suite of statistical and graphical products from which to evaluate performance in replicating observed conditions. DES/DAQ sent WRF output and AMET results to Ramboll for an initial evaluation to determine if the simulation is suitable for this work. Ramboll stratified statistical performance into groups of surface meteorological stations within Las Vegas, the Mojave Desert, and other areas of Southern California. We also reviewed performance during specific high ozone periods, and qualitatively reviewed performance for the Las Vegas and San Diego radiosonde observation (RAOB) profiles.

From that initial evaluation, Ramboll determined that the EPA WRF run performed well overall, especially in the LVV, meeting statistical benchmarks. However, some larger wind and temperature errors were noted in the LVV during some high ozone periods, and particularly during July 1-2 related to poorly simulated convective activity.

5.1 WRF Modeling of June 29 – July 4, 2016

The July 1-2 period was considered key to ozone modeling as it represents a period believed to involve mostly local ozone production with perhaps some regional transport. As directed by DES/DEQ, Ramboll conducted a short WRF simulation in an attempt to improve overall performance during the July 1-2 high ozone episode. The WRF configuration was based on a simulation recently conducted for WESTAR (Ramboll, 2021a), which in turn was based on the best performing runs (considering convective rainfall) from numerous WRF comparison studies conducted for WRAP and New Mexico over the past few years. Details of the configuration of this run are listed in Table 5-1 for direct comparison to EPA's configuration.

As described below, we assessed EPA's and Ramboll's WRF model performance in more detail against standard routine local and regional observational data. The decision to use the alternative WRF simulation to bridge the July 1-2 period was based on performance comparisons for winds, temperature, humidity, and rainfall patterns. EPA's and Ramboll's WRF 4 km resuls were processed to CAMx-ready inputs on the CC4c2 modeling grid using the WRFCAMx interface program. WRF output was also processed to model-ready inputs for the Community Multiscale Air Quality (CMAQ) model using the Meteorology-Chemistry Interface Processor (MCIP) for processing on-road and biogenic emissions. Those steps are detailed in later Sections of this report.

5.2 Summary of Conclusions from the WRF Evaluation

Ramboll initially determined that the EPA WRF run performed well overall during the summer 2016 season, meeting statistical benchmarks especially in the LVV. The additional analyses described here confirmed that the EPA WRF run was applicable for CAMx photochemical modeling over the majority of the May-August 2016 ozone modeling period, for the following reasons:

- Model performance in replicating surface temperature and wind at meteorological monitoring sites within the LVV was rather good relative to other recent WRF modeling performed in the western US, meeting statistical benchmarks;
- While surface humidity tended to be overstated in EPA's modeling, that particular variable has the least influence on CAMx ozone performance;
- WRF was mostly able to replicate vertical profiles of temperature and humidity rather well, according to Las Vegas RAOB data.

Based on our detailed performance evaluation of the July 1-2 "bridge" run, we recommended supplanting EPA's WRF results with Ramboll's WRF results for the June 30 – July 2, 2016 period for use in CAMx. In order to reduce the potential for a sudden shift in meteorological parameters on July 1, we recommended using the alternative WRF simulation starting on June 30, a day with lower ozone in the region. Our reasoning for these recommendations include:

- Dramatically improved agreement with observed temperature conditions, both at the surface and in the vertical during the July 1-2 convective period;
- Improved agreement with precipitation patterns based on observations day-by-day;
- Improved agreement with observed humidity early in the episode, although the model exhibited large under predictions later in the period;
- Improved surface winds during certain afternoon hours when spurious convection in EPA's WRF run on July 1 and 2 caused strong downdraft outflows over the LVV.

Temperature performance is critical for CAMx modeling: temperature drives the diurnal evolution of mixing depth and influences temperature-sensitive emissions and chemical rates that drive ozone formation. The removal of spurious convection greatly improved the characterization of temperature and winds influenced by simulated convective downdrafts. In summary, a drier, less cloudy, warmer environment was preferred for photochemical modeling, even if such conditions tended to be somewhat overstated, so that we maximized the potential for generating higher ozone on these important locally-drive ozone exceedance days.

5.3 Model Performance Evaluation Approach

Evaluation of EPA's California/Nevada WRF application and Ramboll's June 30 – July 4 bridge run included quantitative and qualitative methods. Quantitative evaluations statistically compare WRF predictions against surface hourly meteorological observations at multiple sites, matched by time and location. Qualitative evaluations graphically compare time series of modeled wind speed/direction, temperature, and humidity to observations at specific sites, and daily to monthly spatial patterns in precipitation. The evaluation was conducted for meteorological observation sites over southern Nevada and California, with particular focus within the LVV.

Quantitative model performance statistics were calculated using AMET and the publicly-available METSTAT tool (Ramboll, 2022d). Both generate graphical and statistical products to evaluate model performance for surface winds, temperatures, and humidity. The purpose of these evaluations is to establish a first-order acceptance/rejection of the simulation based on adequate replication of the weather phenomena in the study area. Thus, this approach screens for obvious model flaws and errors. Statistical measures include mean observation and prediction, prediction signed error (bias), and prediction unsigned error (absolute or gross error).

Mean observation (Mo) is calculated using values from 1 or many sites over a given period:

$$M_o = \frac{1}{IJ}\sum_{j=1}^{J}\sum_{i=1}^{I} O_j^i$$

where O^i_j is the individual observed quantity at site i and time j, and the summations are over all sites (I) and over time periods (J).

Mean Prediction (Mp) is calculated from simulation results that are interpolated to each observation site used to calculate the mean observation for a given period:

$$M_p = \frac{1}{IJ}\sum_{j=1}^{J}\sum_{i=1}^{I} P_j^i$$

where P^i_j is the individual predicted quantity at site i and time j. Note the predicted mean wind speed and mean resultant direction are derived from the vector-average of the east-west component u and north-south component v that are output by WRF.

Bias (B) is calculated as the mean signed difference in prediction-observation pairings with valid data within a given analysis region and for a given period:

$$B = \frac{1}{IJ}\sum_{j=1}^{J}\sum_{i=1}^{I}\left(P_j^i - O_j^i\right)$$

Gross Error (E) is calculated as the mean absolute difference in prediction-observation pairings with valid data within a given analysis region and for a given period:

$$E = \frac{1}{IJ}\sum_{j=1}^{J}\sum_{i=1}^{I}\left|P_j^i - O_j^i\right|$$

Note that the bias and gross error for winds are calculated from the predicted-observed residuals in speed and direction (not from vector components u and v). The direction error for a given prediction-observation pairing is limited to range from 0 to ±180°.

Root Mean Square Error (RMSE), which is another form of unsigned error, is calculated as the square root of the mean squared difference in prediction-observation pairings with valid data within a given analysis region and for a given period:

$$RMSE = \left[\frac{1}{IJ}\sum_{j=1}^{J}\sum_{i=1}^{I}\left(P_j^i - O_j^i\right)^2\right]^{\frac{1}{2}}$$

The RMSE, as with the gross error, is a good overall measure of model performance. However, since large errors are weighted heavily (due to squaring), large errors in a small sub-region may produce a large RMSE even though the errors may be small and quite acceptable elsewhere.

To put the statistical performance of a meteorological model simulation into context for air quality model applications, specific statistics are compared to performance benchmarks. The purpose of the benchmarks is to understand how good or poor the results are relative to the history of other model applications throughout the United States. Table 5-2 lists the meteorological model performance benchmarks that were considered in this study. The simple benchmarks (Emery et al., 2001) were developed by analyzing well-performing meteorological model results in areas of mostly flat terrain and simple meteorological conditions (e.g., stationary high pressure). The complex benchmarks (Kemball-Cook et al., 2004) were developed during the 2002 WRAP visibility modeling and are appropriate for applications in complex terrain and more variable meteorological conditions that occur in areas such as the Rocky Mountains and Alaska. McNally et al. (2008) analyzed multiple annual runs that included complex terrain conditions and suggested an alternative set of benchmarks for temperature under more complex conditions. The complex benchmarks in Table 5-2 represent the maximum among those proposed by Kemball-Cook and McNally.

Both 4 km WRF applications were statistically evaluated against these benchmarks, including bias and error in temperature, wind direction and mixing ratio, and bias and RMSE in wind speed. Observations for WRF verification and evaluation were obtained from the National Climate Data Center's (NCDC) global-scale, quality-controlled DS3505 integrated surface hourly dataset. Global hourly and synoptic observations are compiled from numerous sources into a single common text format and common data model. The DS3505 database contains records of most official surface meteorological stations from airports, military bases, reservoirs/dams, agricultural sites, and other sources dating from 1901 to the present.

Table 5-2. Meteorological model performance benchmarks for simple conditions (Emery et al., 2001) and complex conditions (Kemball-Cook et al., 2004; McNally et al, 2008).

Parameter	Simple	Complex
Temperature Bias	≤ ±0.5 K	≤ ±2.0 K
Temperature Error	≤ 2.0 K	≤ 3.5 K
Humidity Bias	≤ ±0.8 g/kg	≤ ±1.0 g/kg
Humidity Error	≤ 2.0 g/kg	≤ 2.0 g/kg
Wind Speed Bias	≤ ±0.5 m/s	≤ ±1.5 m/s
Wind Speed RMSE	≤ 2.0 m/s	≤ 2.5 m/s
Wind Dir. Bias	≤ ±10 degrees	--
Wind Dir. Error	≤ 30 degrees	≤ 55 degrees

*Dashes indicate that the parameter was not addressed by the referenced study.

The WRF surface meteorological model performance metrics were compared against the simple and complex model performance goals using "soccer plots." Soccer plots present WRF statistics as symbols in X/Y space (e.g., temperature bias as X and temperature error as Y) along with the performance benchmarks plotted as a box or "goal". The closer the symbols are to zero, the better the model performance. Statistical symbols within the goal indicate that WRF performs similarly to or generally better than the history of WRF simulations conducted for air quality modeling applications. Statistical symbols outside the goal indicate that WRF performs generally worse.

The hourly prediction and observation data that feed into the statistical calculations were plotted as time series by AMET or METSTAT. Either site-specific or site-aggregated time series can be developed. These types of plots were qualitatively reviewed to assess the ability of WRF to replicate intra-diurnal and inter-daily variations in temperature, winds, and humidity. Additionally, simulated profiles of temperature and humidity were plotted along with twice-daily Las Vegas RAOB data (KVEF). These plots provide an important assessment of the vertical structure of the atmosphere. The surface and profile assessments focused on periods when ozone was high or exceeded the NAAQS to evaluate the extent to which meteorology is properly characterized during these most important events.

A proper simulation of precipitation is also critically important for modeling ozone formation within, and regional transport into the CCNAA. Plots were generated to assess precipitation patterns and rates relative to measured conditions. Oregon State University (OSU) publishes precipitation analysis fields based on observations that can be used to qualitatively evaluate the WRF precipitation fields. The Parameter-elevation Relationships on Independent Slopes Model (PRISM) is used to generate the precipitation analysis fields (Daly et al., 2008). The PRISM interpolation method develops data sets that reflect, as closely as possible, the current state of knowledge of spatial climate patterns in the United States. PRISM calculates a climate – elevation regression for each digital elevation model (DEM) grid cell, and rain gauge stations entering the regression are assigned weights based primarily on the physiographic similarity between the station and the grid cell. Factors considered are location, elevation, coastal proximity, topographic facet orientation, vertical atmospheric layer, topographic position, and orographic effectiveness of the terrain.

Spatial plots of the WRF daily and monthly precipitation fields were compared with the PRISM spatial maps in a qualitative model evaluation. We focused on WRF performance for daily convective precipitation because WRF tends to overstate it, which can suppress ozone formation and improperly influence wind, temperature, and moisture patterns. However, the PRISM precipitation interpolation scheme works better for organized synoptic weather systems than for stochastic convective showers, which tend to be spotty and intermittent. This is the primary reason why the analysis of precipitation performance remains as a qualitative comparison of spatial patterns and magnitudes.

5.4 Evaluation of EPA WRF 4 km Run

We compared EPA WRF model performance against available observations in the LVV region during high ozone periods that occurred during the summer of 2016. For surface performance, we graphically evaluated modeled temperature, humidity and winds against observations at Harry Reid International Airport (KLAS), while statistically evaluating WRF performance for those same variables across four routine airport monitoring sites within the LVV (KLAS, KLSV, KVGT and KHND in Figure 5-2). We also evaluated model performance for vertical temperature and humidity profiles against RAOB measurements from the KVEF Las Vegas radiosonde. Finally, we graphically compared daily simulated precipitation patterns against PRISM analyses on high ozone days when either WRF or observations reported precipitation in the region. For the remainder of this discussion, we refer to the EPA WRF run as “run0” and Ramboll’s alternative WRF run for June 29 – July 4 as “run1”.

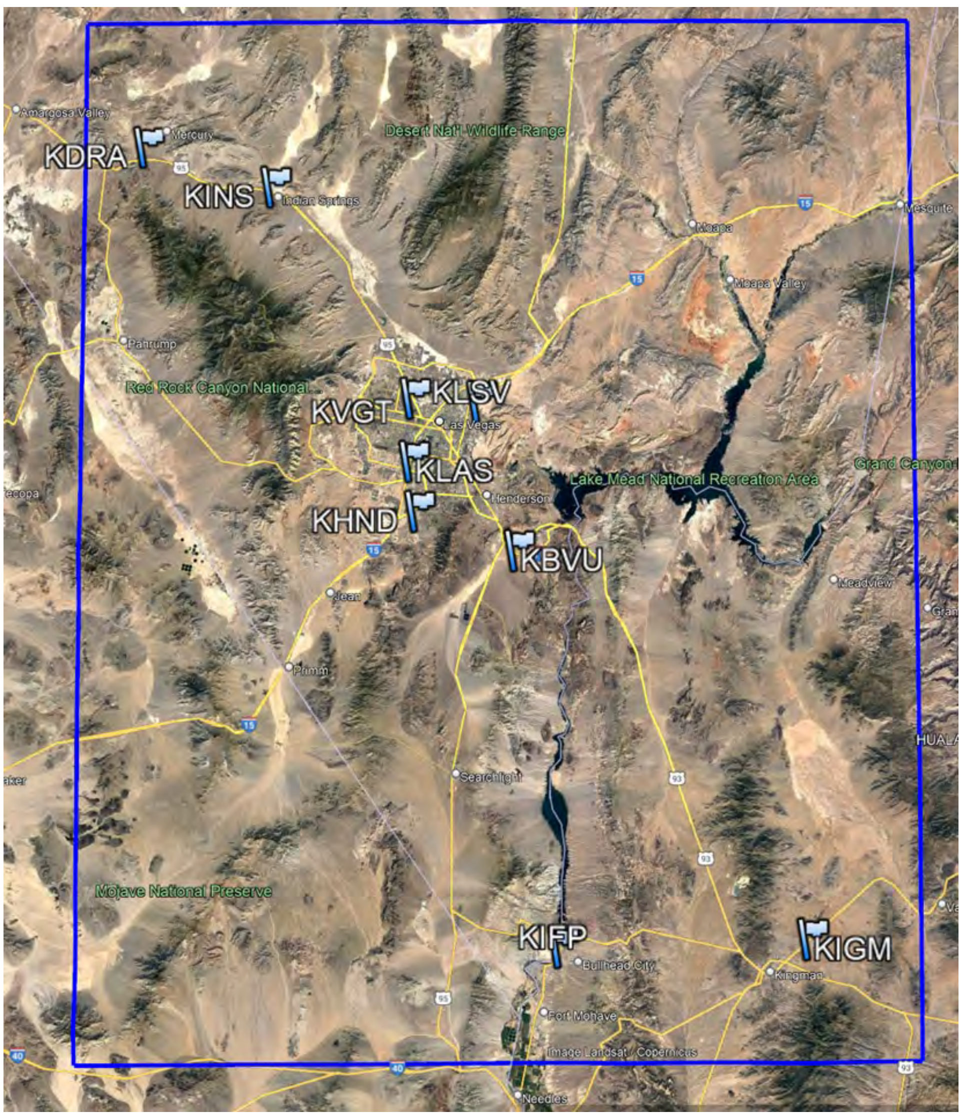


Figure 5-2. Locations of DS3505 surface airport meteorological monitoring sites (flags) within the CC4c2 CAMx domain (shown in blue).

We evaluated run0 performance for each of eight weeklong high ozone periods in 2016 as defined by Clark County DES/DAQ:

1. May 14-20
2. June 2-8
3. June 22-28
4. July 1-7
5. July 11-17
6. July 23-29
7. August 11-17
8. August 19-25

5.4.1 Surface Statistical Performance

Figure 5-3 displays soccer plots among the 8 high ozone periods (colored symbols) for wind speed (top left), wind direction (top left), temperature (bottom left) and water vapor mixing ratio (bottom left). We note that the benchmarks were designed for evaluating monthly performance across multiple sites within a region. In general, bias and error statistics look better when calculated for larger data populations (Emery et al., 2001). Therefore, we expect that statistical performance over shorter periods (as in weeklong high ozone periods) and a few sites to result in a wider range relative to benchmarks.

All 8 ozone periods show a negative wind speed bias (top left panel of Figure 5-3), with 3 of the 8 periods within the simple bias benchmark (≤±0.5 m/s) and all within the complex bias benchmark (≤±1.5 m/s). Five of the ozone periods achieve the simple benchmark for RMSE (≤2.0 m/s), and all achieve the complex benchmark (≤2.5 m/s).

Wind direction performance (top right panel of Figure 5-3) shows that 4 of the 8 high ozone periods meet the simple/complex benchmark for bias (≤±10°), and the other 4 periods are within the 10°-20° range. None of the periods meet the simple benchmark for error (≤30°), though all periods meet the complex benchmark (≤55°).

Temperature performance (bottom left panel of Figure 5-3) shows a general negative bias for 6 of the 8 high ozone periods. While all 8 periods lie within the complex benchmark (≤±2.0 K), 3 periods (May 14-20, July 11-27 and August 11-17) achieve the simple benchmark (≤±0.5 K). All 8 high ozone periods achieve the complex benchmark for error (≤3.5 K) and only one ozone period (July 1-7) lies outside the simple benchmark (≤2.0 K).

Water vapor mixing ratio performance (bottom right panel of Figure 5-3) shows a persistent positive bias across all 8 high ozone periods. Five periods meet the simple benchmark for bias (≤±0.8 g/kg), and one period (June 22-28) lies outside of the complex benchmark (≤±1.0 g/kg). All 8 high ozone periods meet the simple/complex benchmark for error (≤2.0 g/kg).

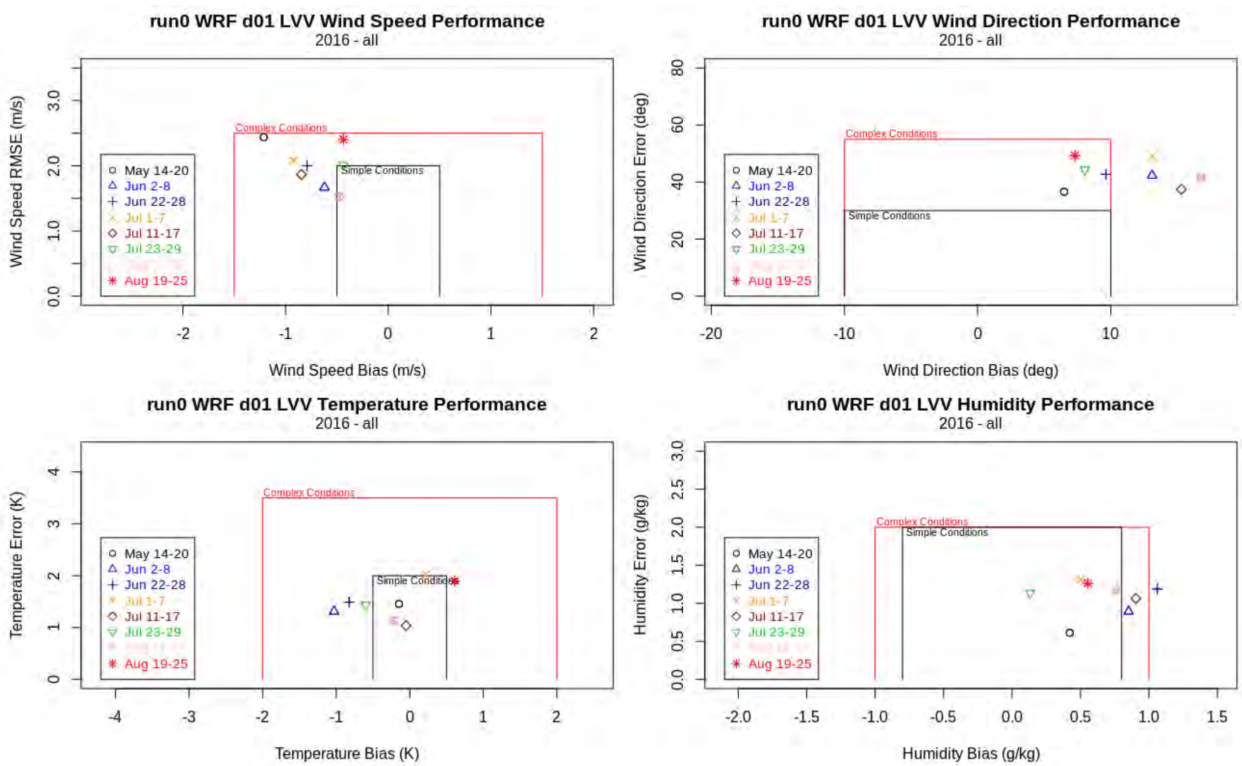


Figure 5-3. Soccer plots comparing model performance statistical metrics from EPA's WRF run against simple and complex benchmarks: 10-m wind speed (top left), 10-m wind direction (top right), 2-m temperature (bottom left) and 2-m water vapor mixing ratio (bottom right). Different symbols refer to each of the eight high ozone periods in 2016.

5.4.2 Time Series

Figures 5-4 through 5-11 show time series at KLAS from WRF run0 (red) and observations (black) for 2-m temperature (1st panel from top), 2-m water vapor mixing ratio (2nd panel), 10-m wind speed (3rd panel) and 10-m wind direction (bottom panel) for each of the 8 high ozone periods. Focusing on temperature, the model is able to replicate the daily midday peaks reasonably well on most days, but modeled temperature tends to drop off at faster rate in the late afternoon/evening hours than observed. Because temperature is tied to mixing, chemistry and emissions, this accelerated temperature drop could have implications for ozone modeling in CAMx. On several days (June 28, July 1-2, 28, August 22-23), modeled temperatures crash suddenly near midday, in contrast to observations. These temperature crashes are paired with large modeled spikes in mixing ratio, suggesting that convective activity in the model is responsible.

The persistent positive mixing ratio bias seen in the soccer plots (bottom right panel of Figure 5-3) is evident in the time series. For some ozone periods (see Figure 5-5 and Figure 5-8 for examples), run0 exhibits a +1 to +2 g/kg bias across nearly all hours.

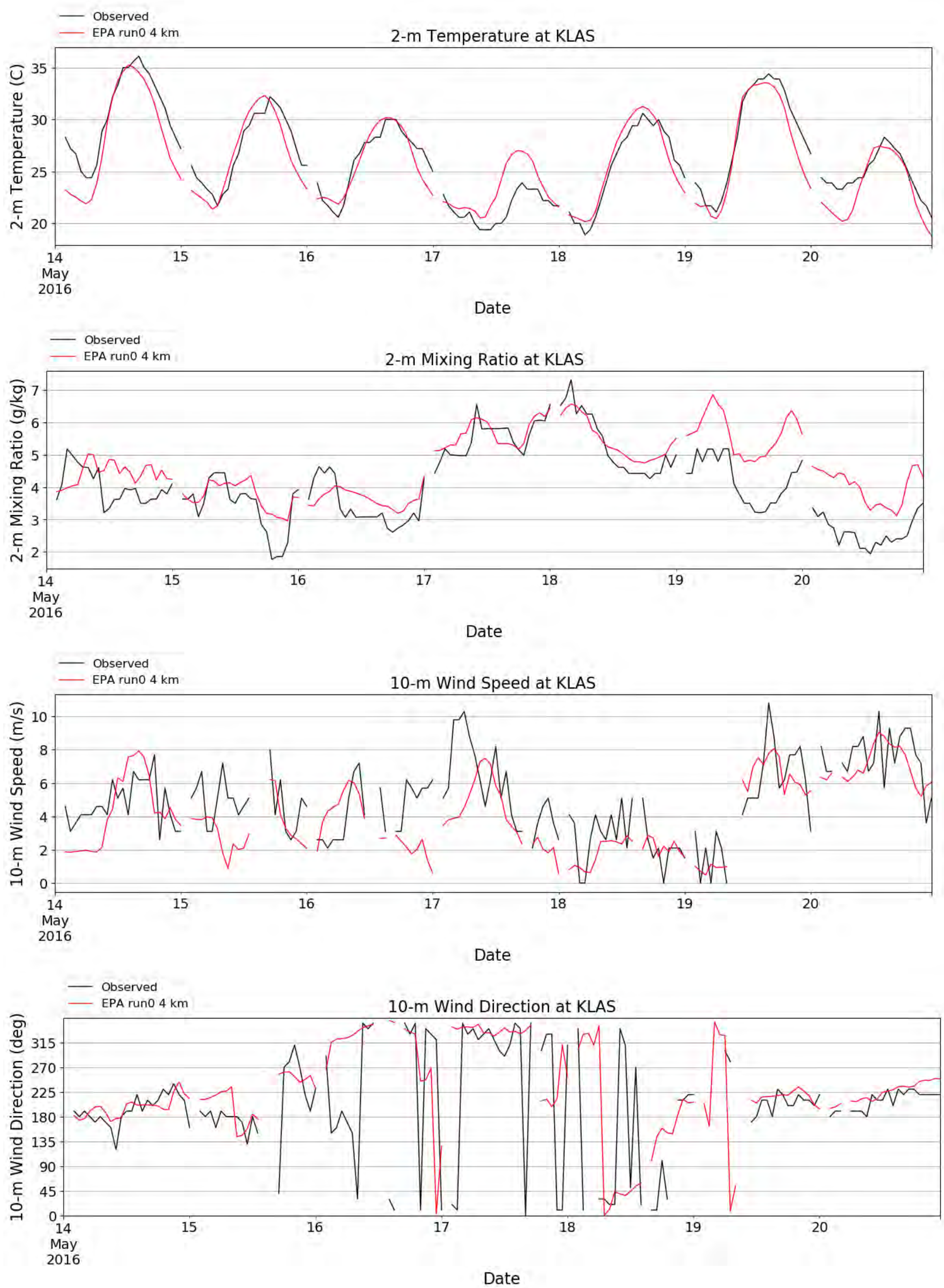


Figure 5-4. Observed (black line) and EPA WRF model (red) 2-m temperature (first panel from top), 2-m water vapor mixing ratio (second panel), 10-m wind speed (third panel) and 10-m wind direction (bottom panel) time series during May 14-20, 2016 at KLAS.

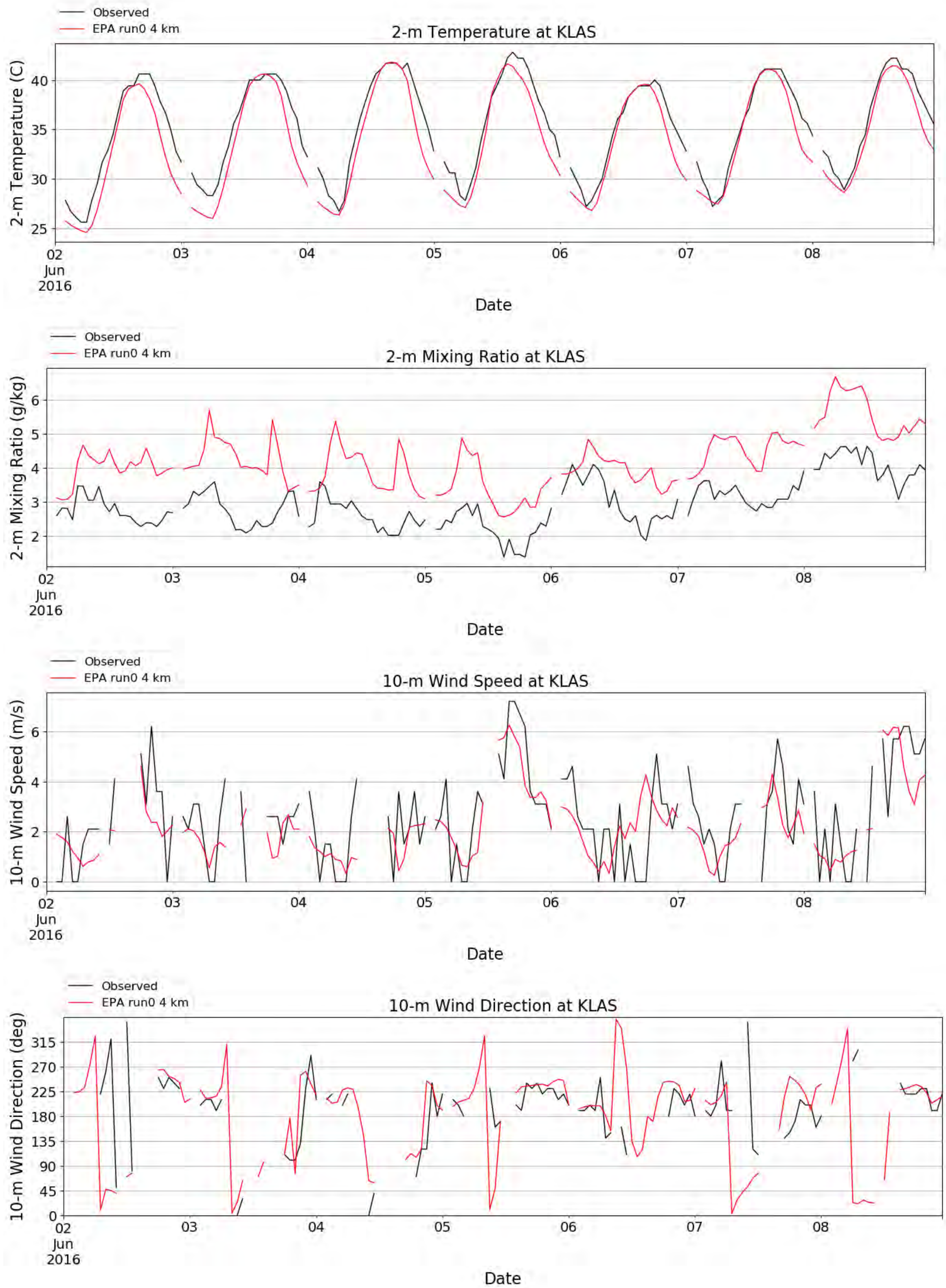


Figure 5-5. Observed (black line) and EPA WRF model (red) 2-m temperature (first panel from top), 2-m water vapor mixing ratio (second panel), 10-m wind speed (third panel) and 10-m wind direction (bottom panel) time series during June 2-8, 2016 at KLAS.

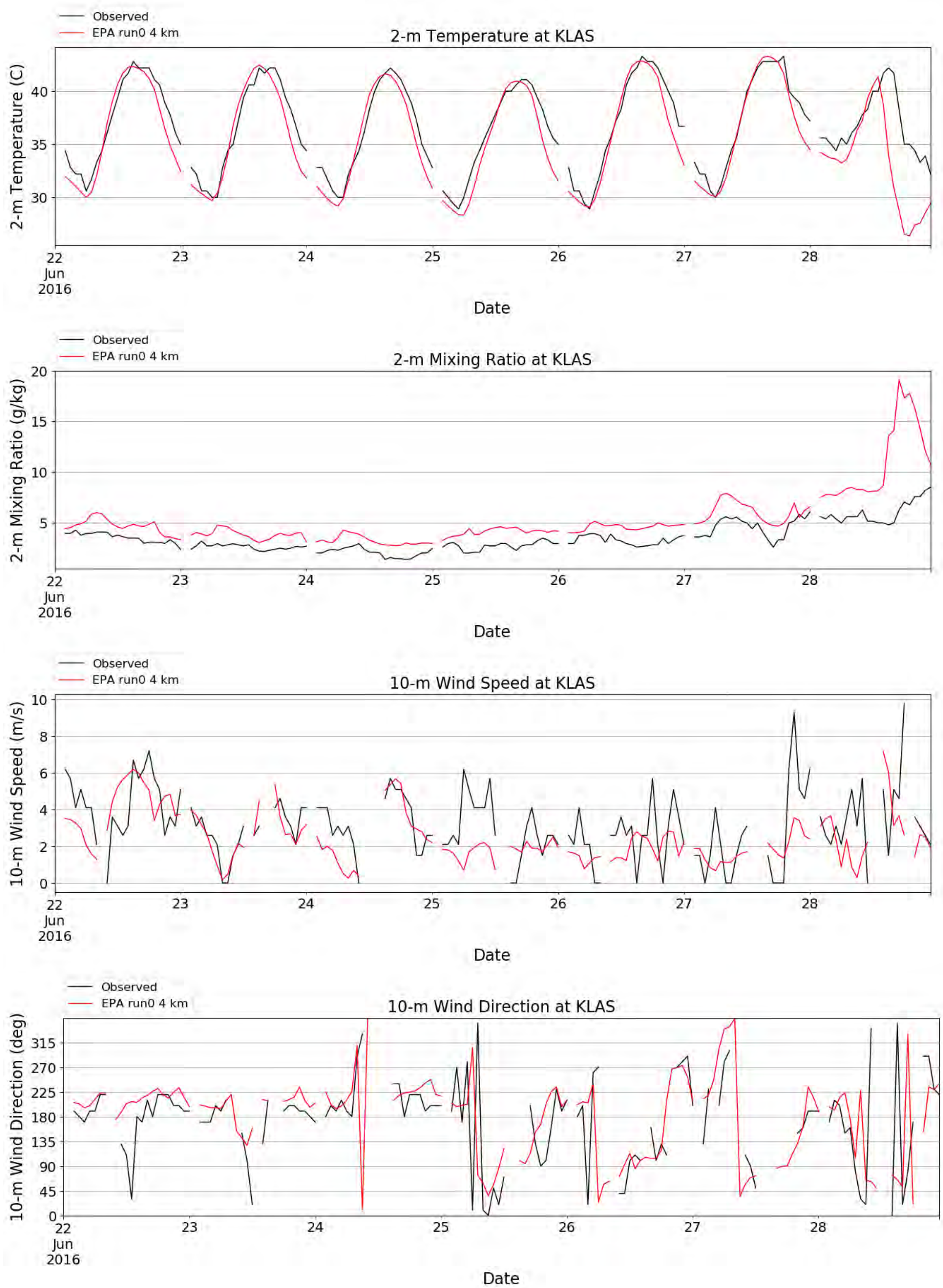


Figure 5-6. Observed (black line) and EPA WRF model (red) 2-m temperature (first panel from top), 2-m water vapor mixing ratio (second panel), 10-m wind speed (third panel) and 10-m wind direction (bottom panel) time series during June 22-28, 2016 at KLAS.

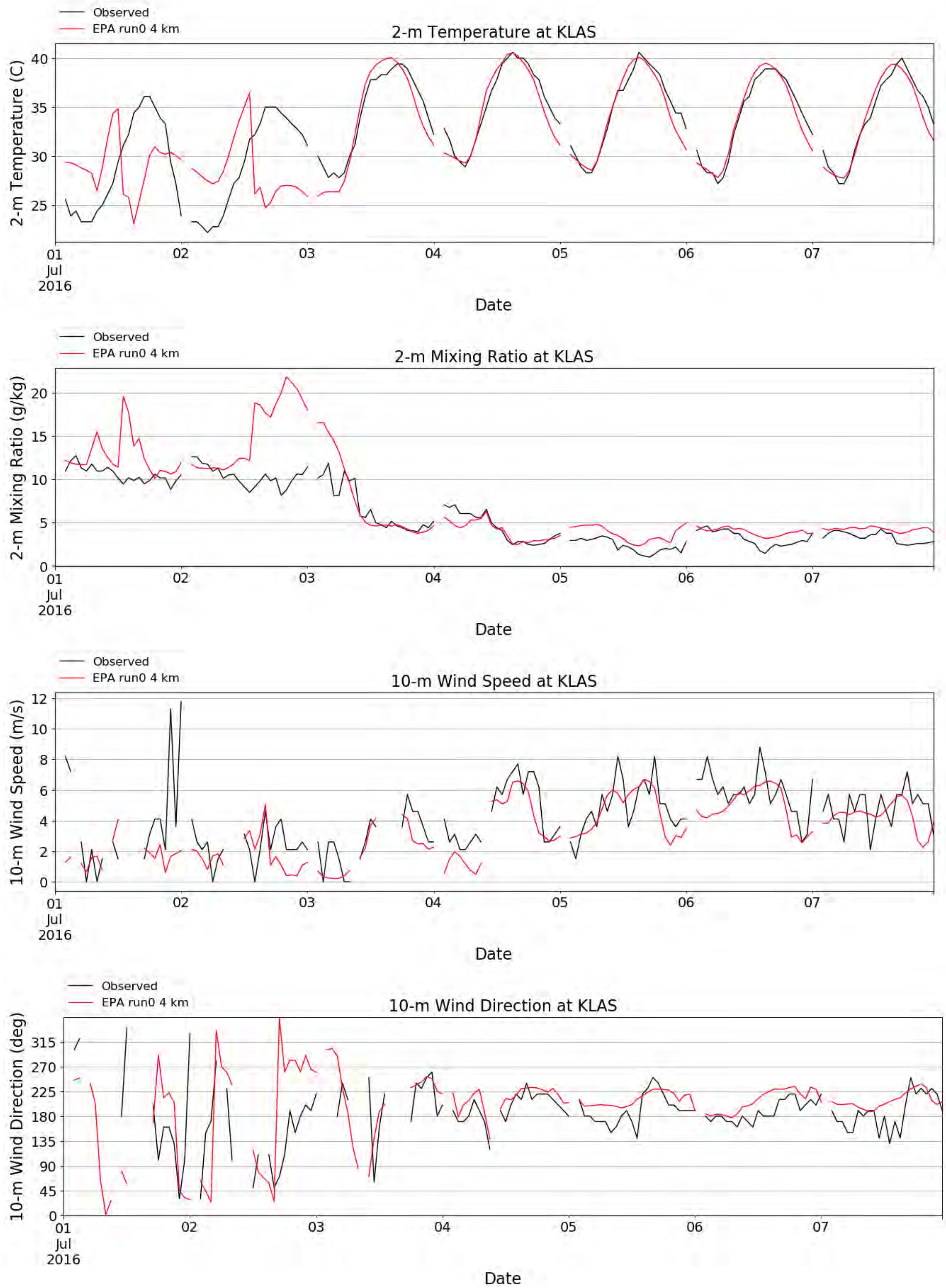


Figure 5-7. Observed (black line) and EPA WRF model (red) 2-m temperature (first panel from top), 2-m water vapor mixing ratio (second panel), 10-m wind speed (third panel) and 10-m wind direction (bottom panel) time series during July 1-7, 2016 at KLAS.

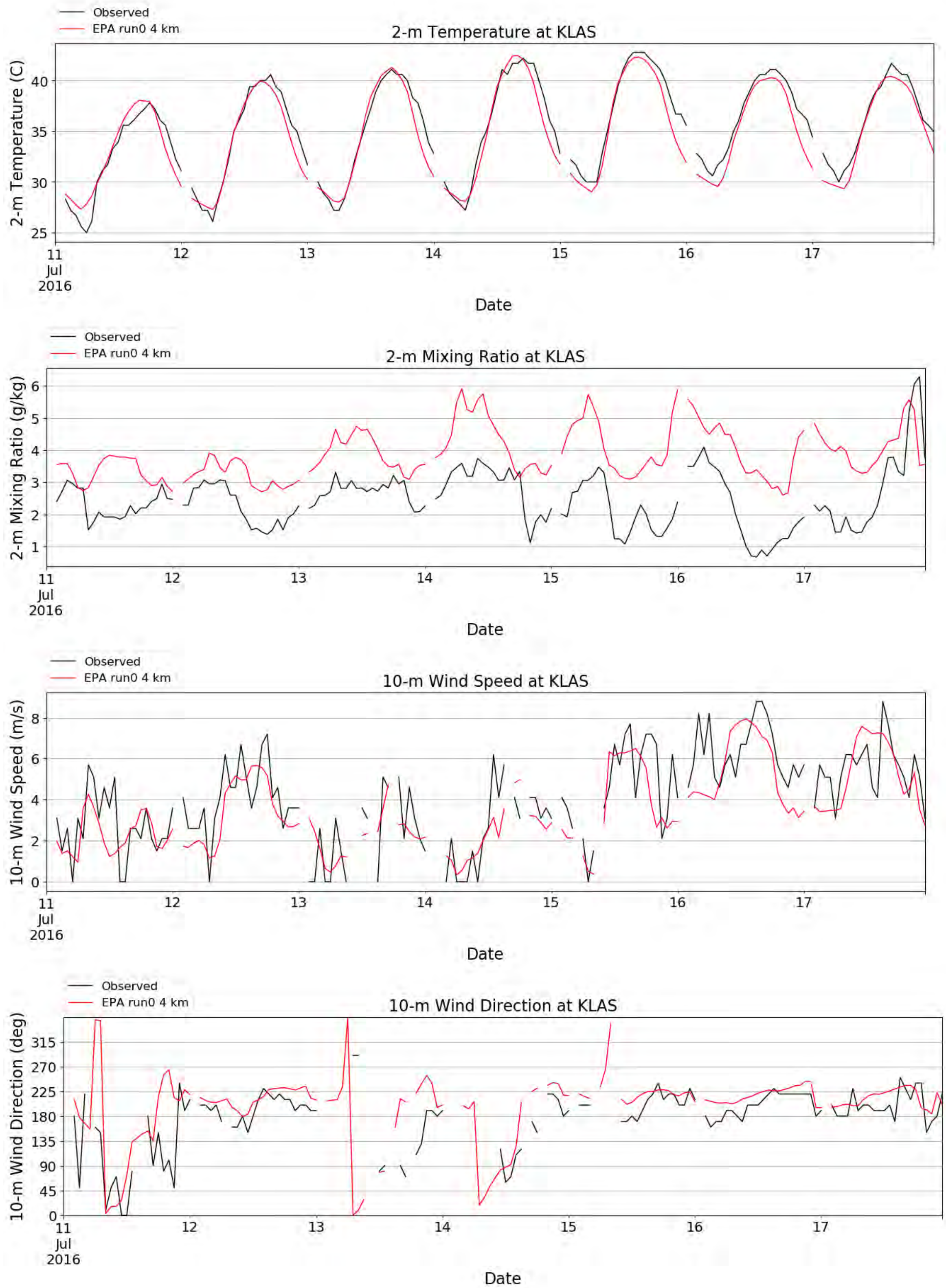


Figure 5-8. Observed (black line) and EPA WRF model (red) 2-m temperature (first panel from top), 2-m water vapor mixing ratio (second panel), 10-m wind speed (third panel) and 10-m wind direction (bottom panel) time series during July 11-17, 2016 at KLAS.

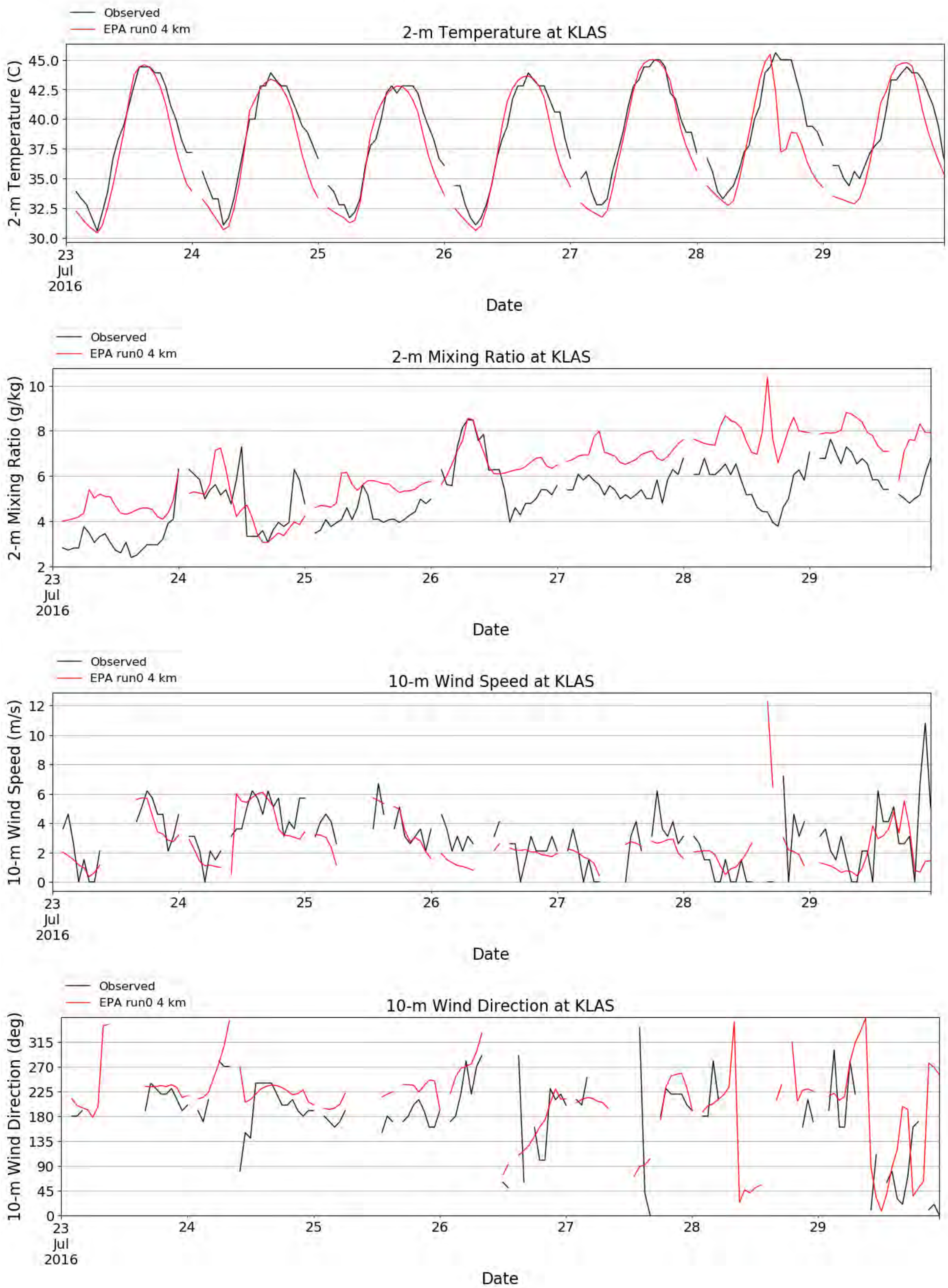


Figure 5-9. Observed (black line) and EPA WRF model (red) 2-m temperature (first panel from top), 2-m water vapor mixing ratio (second panel), 10-m wind speed (third panel) and 10-m wind direction (bottom panel) time series during July 23-29, 2016 at KLAS.

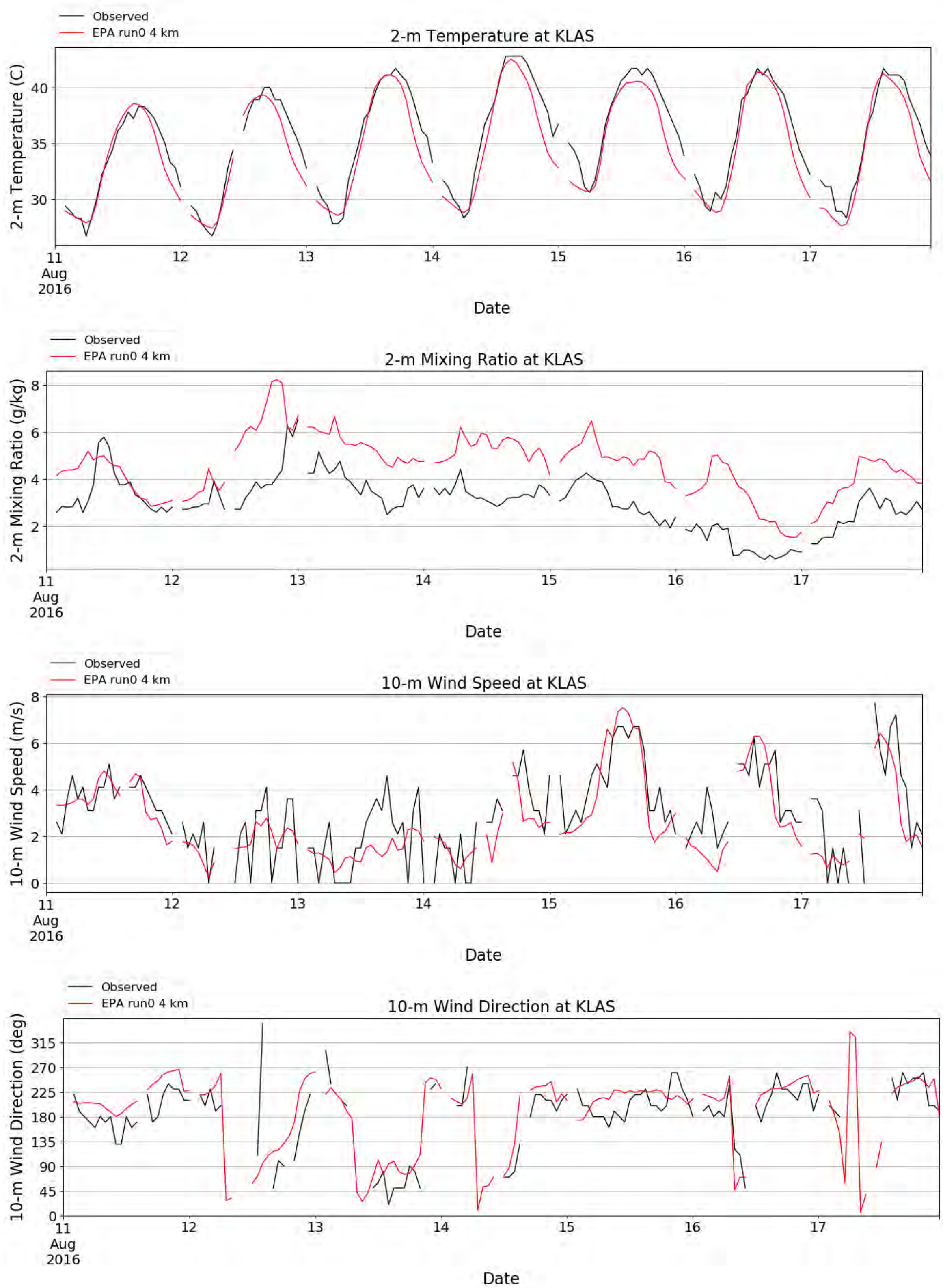


Figure 5-10. Observed (black line) and EPA WRF model (red) 2-m temperature (first panel from top), 2-m water vapor mixing ratio (second panel), 10-m wind speed (third panel) and 10-m wind direction (bottom panel) time series during August 11-17, 2016 at KLAS.

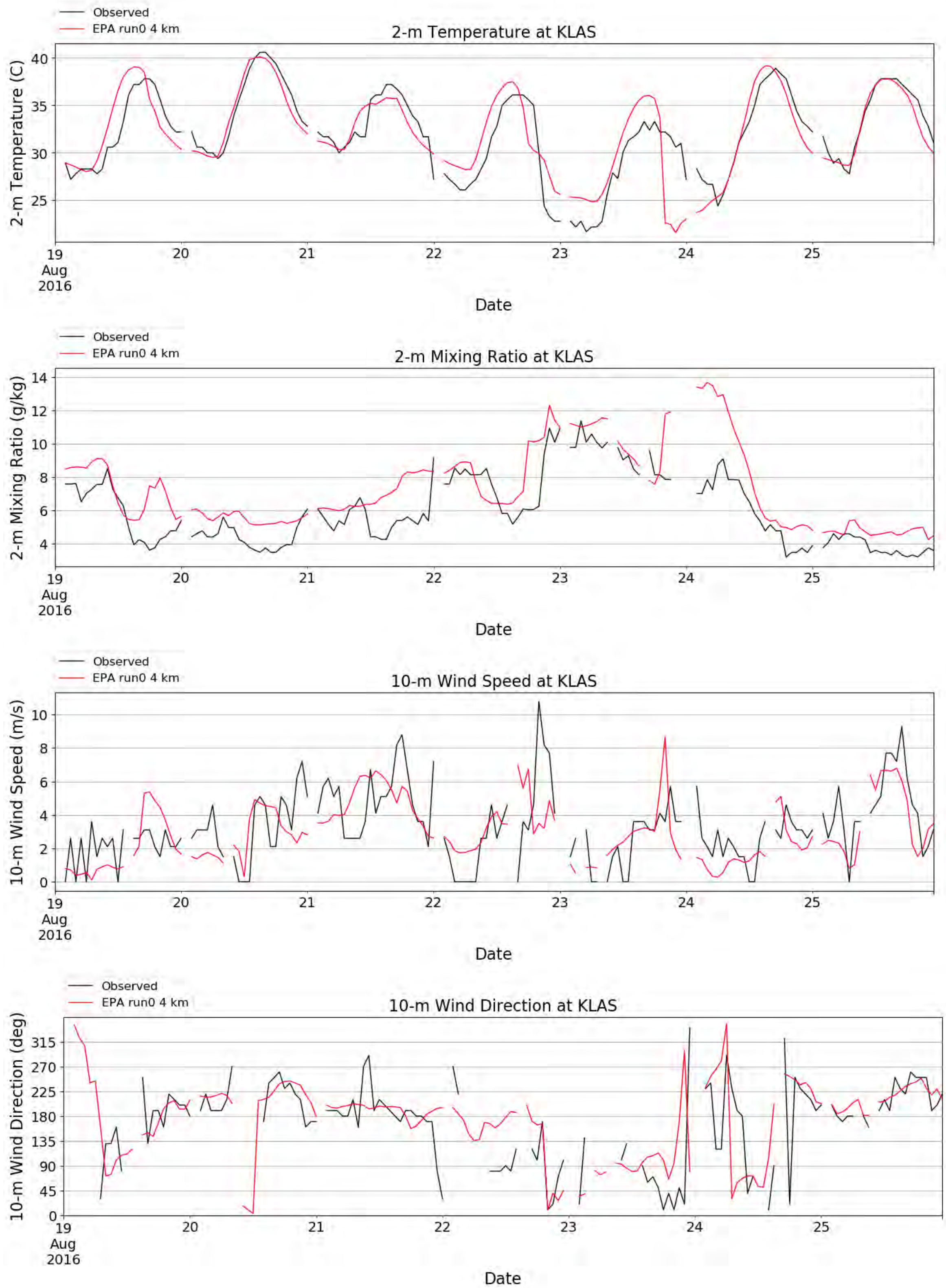


Figure 5-11. Observed (black line) and EPA WRF model (red) 2-m temperature (first panel from top), 2-m water vapor mixing ratio (second panel), 10-m wind speed (third panel) and 10-m wind direction (bottom panel) time series during August 19-25, 2016 at KLAS.

The model characterizes observed variation in wind speed reasonably well, but with a persistent negative bias. During periods of convective activity (see July 28 in Figure 5-9 for an example), the model sometimes shows large spikes in wind speed, which could be the result of resolved convective downburst winds in the model that temporarily lead to large positive wind speed biases. The model appears to capture observed wind direction shifts but does not exhibit as much hourly variation as observed. We note that missing wind direction observations due to calm wind speeds are frequent during high ozone periods.

5.4.3 Vertical Profile Comparisons

We evaluated temperature and humidity profiles from WRF run0 against measurements from the KVEF RAOB (location shown in Figure 5-12). For brevity, this section presents profile comparisons for two high ozone days at 5 PM PDT (00 UTC): July 28 and August 24. We selected these two days as generally representative of best (August 24) and worst (July 28) performance outside of the July 1-2 period.

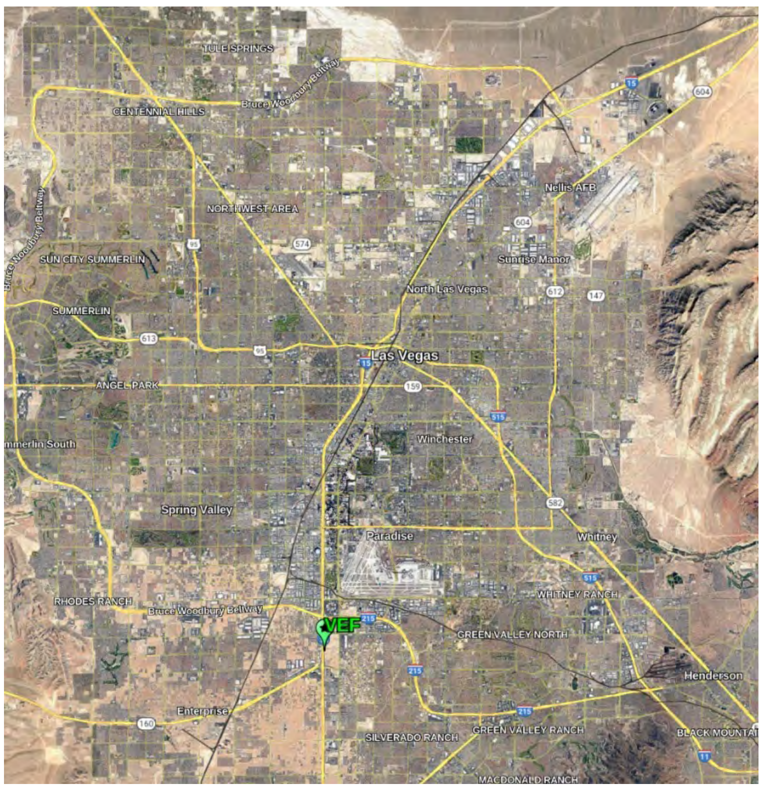


Figure 5-12. Map of Las Vegas showing location of KVEF RAOB site.

Figure 5-13 shows temperature (solid lines) and dewpoint temperature (dashed lines) profiles on August 24, 2016 at 5 PM PDT. Run0 shows good agreement with the RAOB measurements for temperature, with nearly identical profiles from the surface to about 2,400 m above mean sea level (AMSL) or about 1,700 m above ground level (AGL). Run0 dewpoint temperature is nearly identical to the corresponding KVEF observation at the surface but stays nearly constant with increasing height while the observed sounding increases markedly just above the surface, then decreases to match run0 at about 3,200 AMSL (~2,500 AGL).

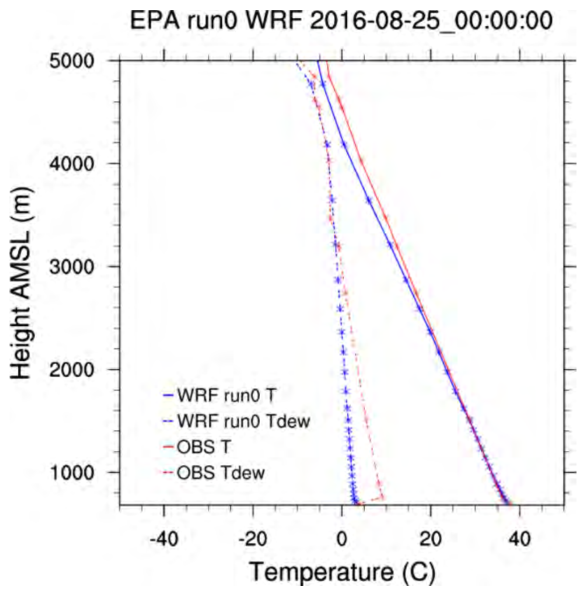


Figure 5-13. Vertical profiles from EPA WRF run0 (blue) and observed (red) temperature (solid lines) and dewpoint temperature (dashed lines) on August 24, 2016 at 5 PM PDT at KVEF.

Figure 5-14 shows the same information on July 28, 2016 at 5 PM PDT. The observed sounding shows a near-surface temperature of 44.2° C (111.6° F), compared to 37.1° C (98.8° F) for run0. The shallow temperature inversion simulated in run0 suggests surface cooling from shading or wet ground resulting from recent or concurrent precipitation. The daily precipitation plot covering this time period does show daily precipitation totaling about 0.1 inches in the vicinity of KVEF (see Figure 5-15 in next section).

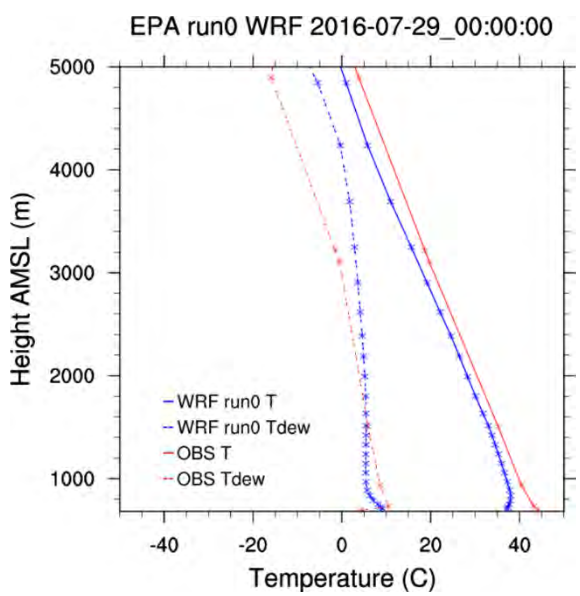


Figure 5-14. Vertical profiles from EPA WRF run0 (blue) and observed (red) temperature (solid lines) and dewpoint temperature (dashed lines) on July 28, 2016 at 5 PM PDT at KVEF.

5.4.4 Qualitative Evaluation for Precipitation

We focused this analysis on the high ozone days when some measurable precipitation was reported in the PRISM data or simulated by WRF run0: July 28-29 and August 23. We present similar precipitation comparisons for EPA's run0 and Ramboll's run1 against PRISM data covering the July 1-2 high ozone period later in this Section.

Figure 5-15 shows daily precipitation patterns from PRISM (left) and run0 (right) for the 24-hour period ending on July 29, 2016 at 5 AM PDT (12 UTC). Both plots show the locations of the DS3505 surface meteorological stations as black circles. The 3 stations in an approximate north/south line are the North Las Vegas Airport (KVGT), McCarran International Airport (KLAS) and Henderson Executive Airport (KHND). The KVEF radiosonde lies just west of KHND and shows daily precipitation around 0.1 inches. The erroneous precipitation in WRF run0 at this location is the likely cause for the substantial near-surface temperature underestimate found in Figure 5-14. Run0 shows better agreement with PRISM throughout most of the LVV with zero or near-zero (< 0.01 inches) precipitation.

Figure 5-16 shows a similar plot for the 24-hour period ending at 5 AM PDT on July 30, 2016. PRISM and run0 are in good agreement (zero or near-zero precipitation) across the LVV, except for an area extending just east and northeast of Nellis Air Force Base (KLSV; just east of VGT) where run0 shows spotty showers resulting in 0.01-0.1 inches of daily precipitation.

Finally, Figure 5-17 shows a daily precipitation comparison plot for the 24-hour period ending at 5 AM PDT on August 24, 2016. PRISM shows shower activity in the western LVV, with heavier amounts to the northwest of Las Vegas. Run0 however, centers shower activity over North Las Vegas, with daily totals exceeding 0.25 inches at KVGT (where PRISM shows < 0.01 inches).

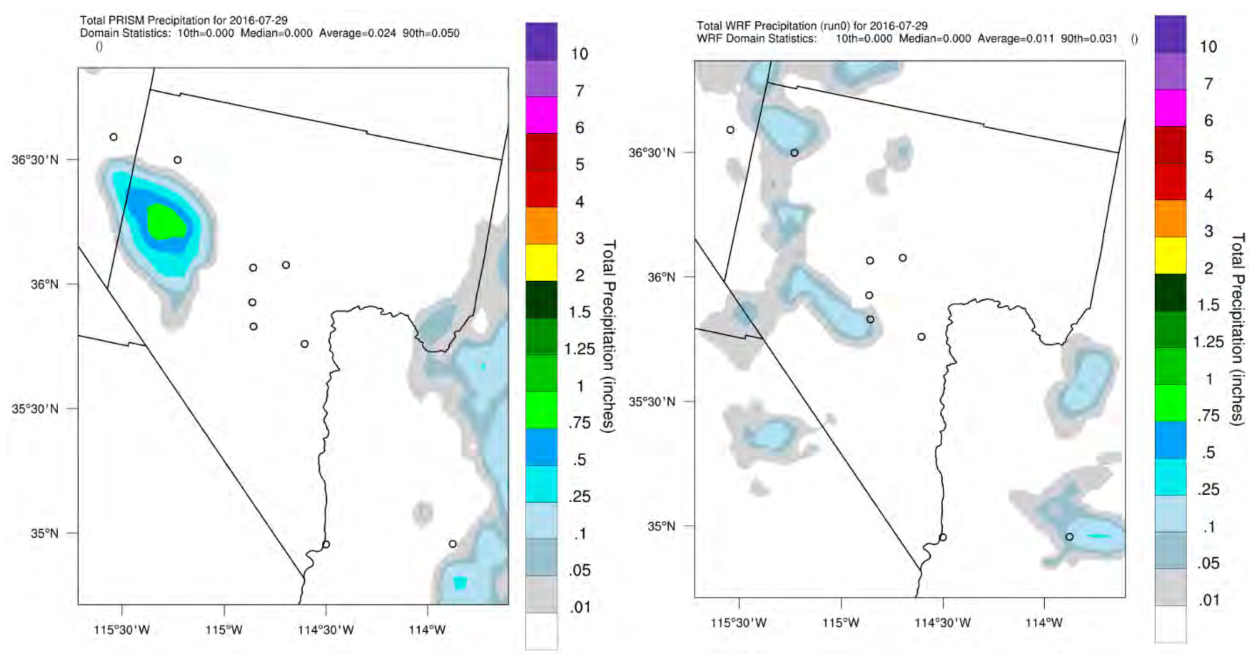


Figure 5-15. Daily precipitation patterns from PRISM based on observations (left) and modeled by EPA WRF run0 (right) for the 24-hour period ending July 29, 2016 at 5 AM PDT.

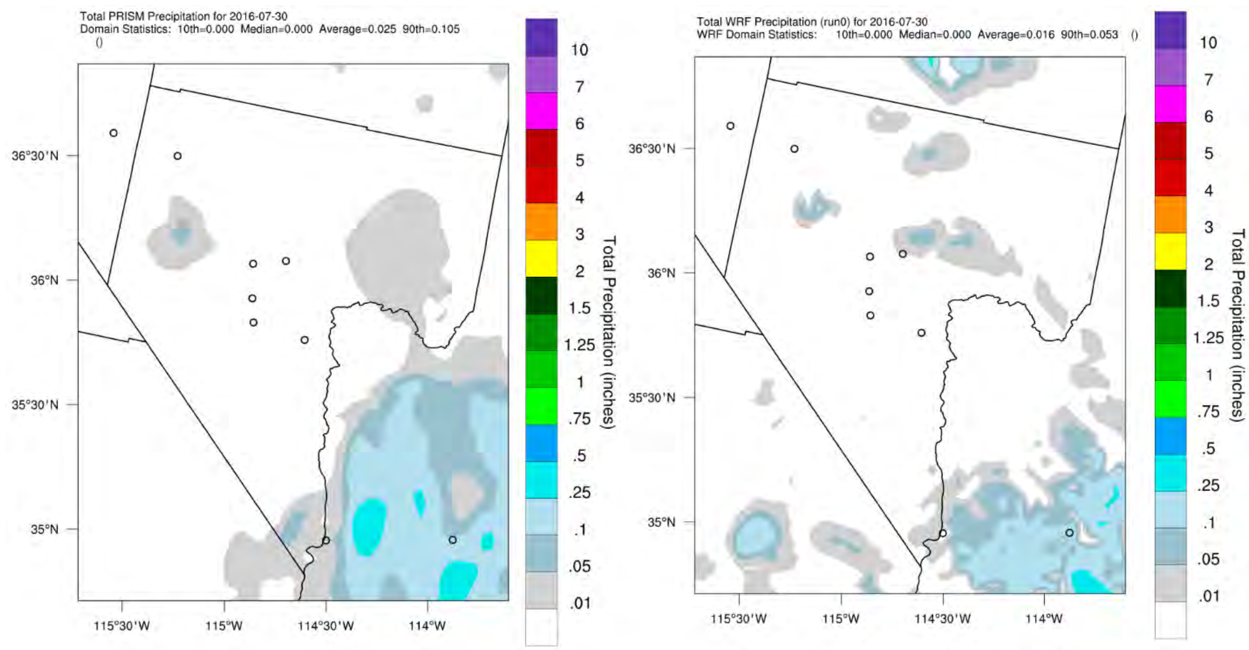


Figure 5-16. Daily precipitation patterns from PRISM based on observations (left) and modeled by EPA WRF run0 (right) for the 24-hour period ending July 30, 2016 at 5 AM PDT.

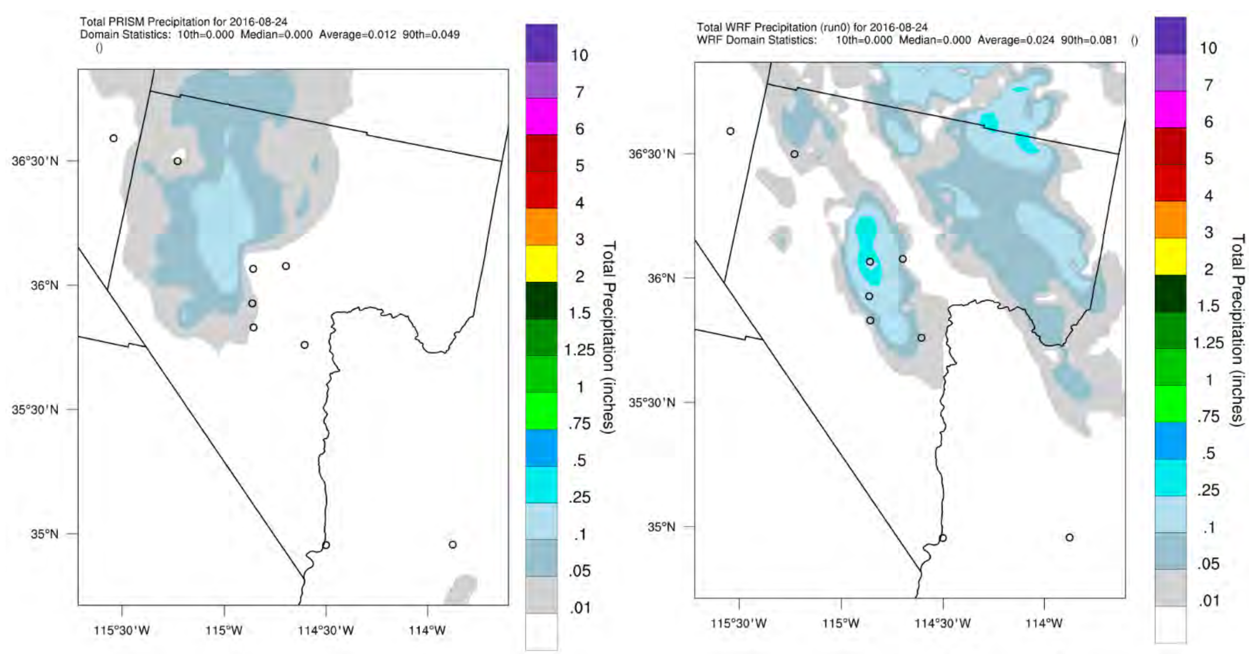


Figure 5-17. Daily precipitation patterns from PRISM based on observations (left) and modeled by EPA WRF run0 (right) for the 24-hour period ending August 24, 2016 at 5 AM PDT.

5.4.5 Phenomenological Evaluation

EPA's modeling guidance (EPA, 2018a) recommends a phenomenological or an event-based meteorological evaluation as part of any air modeling study. As part of the phenomenological evaluation for this study, we evaluated how large-scale meteorological features above terrain are simulated in WRF via observational analyses. Figure 5-18 shows an example comparison of a 700 mb upper air analysis chart (left panel; height contours in grey; temperature contours shown as red dashed lines; dewpoint temperatures exceeding -4°C shown as green lines) and 700 mb WRF 4 km run0 (right) height contours (purple), wind vectors and temperature on June 23, 2016 at 5 PM PDT. Figure 5-19 shows a similar comparison at the 500 mb level over North America from the WRF 12 km run on June 24, 2016 at 5 AM PDT. The orientation of WRF run0 height contours generally agree with those shown on the analysis chart. WRF winds tend to agree qualitatively with the upper air stations in both speed and direction. Over the southwestern US and LVV specifically, WRF winds indicate more stagnation and therefore a larger deviation in wind direction than is observed as the trough moves through Southern California and Nevada. Our examination of similar comparison plots throughout the summer 2016 modeling period revealed generally good qualitative agreement between WRF and the height contours and wind vectors as depicted on the analysis charts.

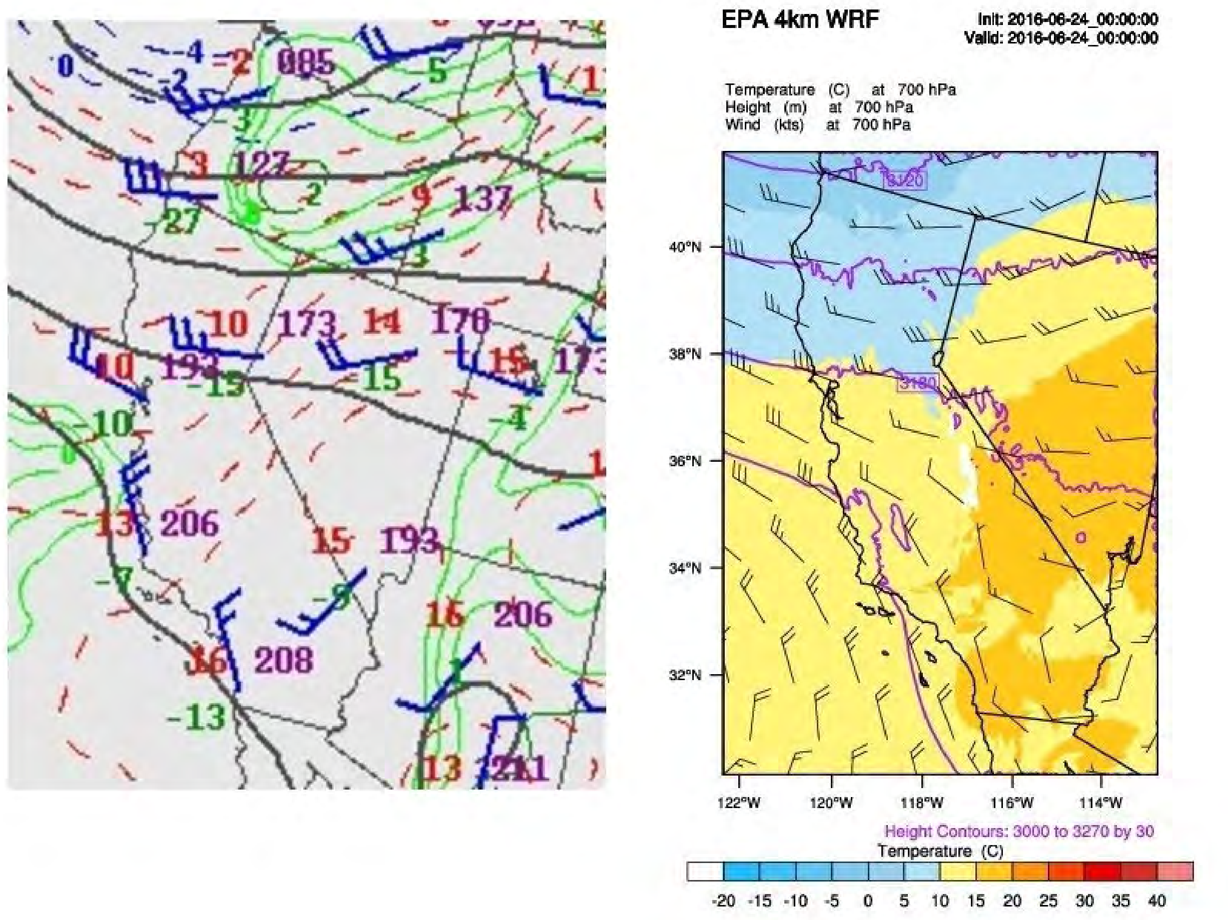


Figure 5-18. 700 mb upper air analysis chart (left; height contours in grey; temperature contours shown as red dashed lines; dewpoint temperatures exceeding -4°C shown as green lines) and 700 mb WRF 4 km run0 (right) height contours (purple), wind vectors and temperature on June 23, 2016 at 5 PM PDT.

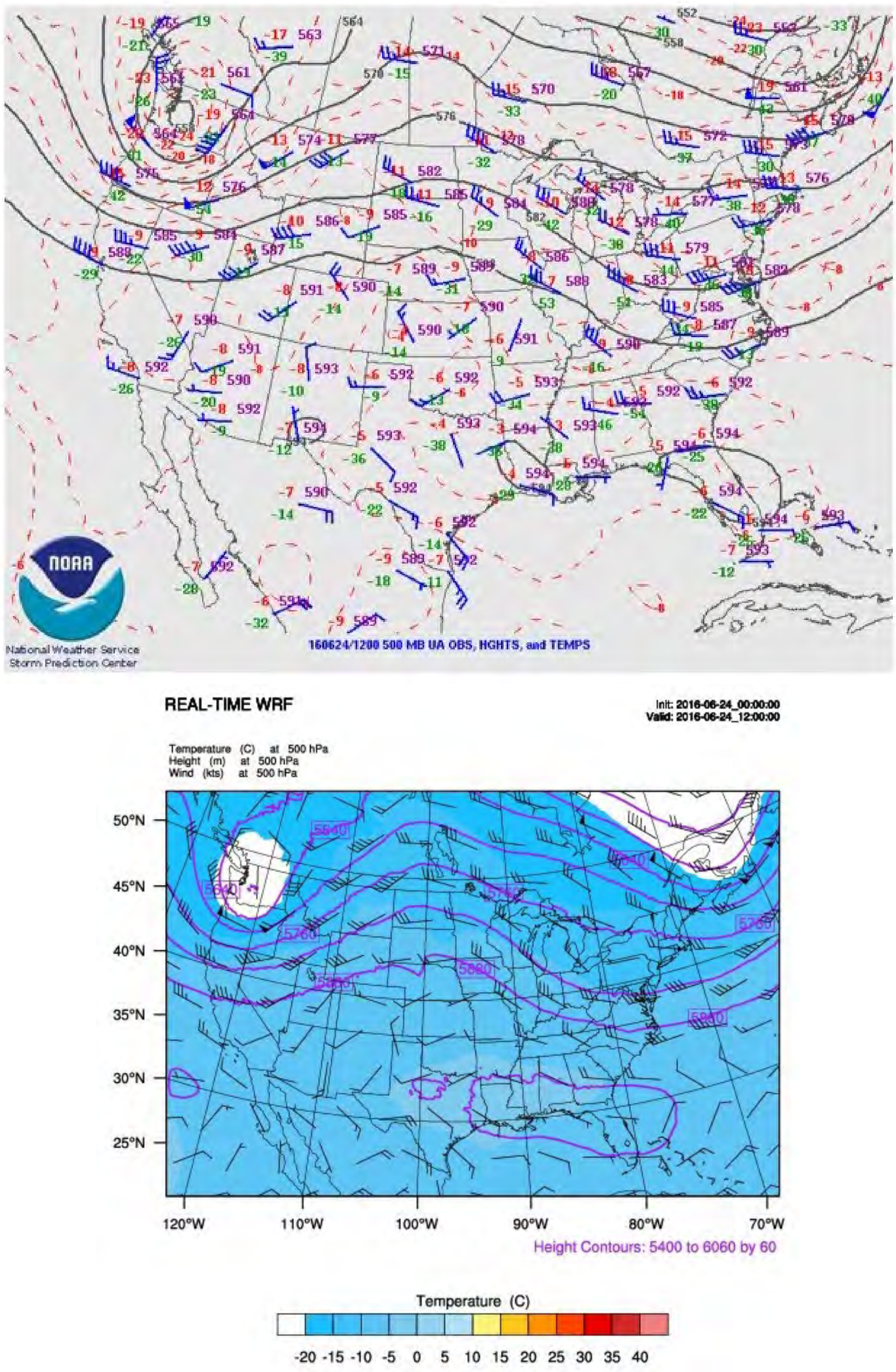


Figure 5-19. 500 mb upper air analysis chart (top; height contours in grey; temperature contours shown as red dashed lines) and 500 mb WRF 12 km (bottom) height contours (purple), wind vectors and temperature on June 24, 2016 at 5 AM PDT.

5.5 Evaluation of WRF 4 km Bridge Run

We compared WRF run1 performance for the June 30 – July 4, 2016 period against the WRF run0 results. As described previously, we configured this alternative WRF simulation in an attempt to improve overall performance during the July 1-2, 2016 high ozone days. These days are considered key to ozone modeling as they represent a period believed to involve mostly local ozone production with perhaps some regional transport.

5.5.1 Surface Statistical Performance

Table 5-3 presents daily 2-m temperature bias and error statistics from run0 and run1 for the June 30 – July 4, 2016 bridge period across the four airport sites within the LVV. The table shows complex benchmarks for bias and error as defined in Table 5-2 and as shown on the soccer plots. We again note that these benchmarks were designed for monthly evaluations across multiple sites within a region. Since we are focusing on daily statistics over an episode that exhibits the worst performance of the entire 4-month modeling period, we would not expect the models to achieve these benchmarks consistently or in unison. Bold text in the table indicates statistics within the complex benchmarks, while green highlighting denotes when daily run1 performance statistics are better (smaller absolute bias or smaller error) than run0. The low biases for run0 during July 1 (+0.8 K) and July 2 (+0.7 K) are misleading as they are the result of some large hourly positive biases nearly "cancelling out" other large hourly negative biases within the same day. This effect is clearly seen in the hourly time series in the next section. Therefore, it is more important to compare unsigned error. Run1 shows a substantially better error statistic on July 1 (2.2 K compared to 4.6 K for run0) and slightly better error statistic on July 2 (4.4 K compared to 5.0 K for run0). Run1 also exhibits a better error statistic for July 3 (0.7 K compared to 1.3 K for run0), but the errors are identical on July 4.

Table 5-3. Daily temperature bias and error statistics for WRF run0 and WRF run1 for June 30 – July 4, 2016 across the LVV. Bold text indicates statistics meeting complex benchmarks, while green highlighted cells show days where run1 outperforms run0.

	Mean Bias (K)					Mean Error (K)				
	6/30	7/01	7/02	7/03	7/04	6/30	7/01	7/02	7/03	7/04
Benchmark	≤ ± 2	≤ ± 2	≤ ± 2	≤ ± 2	≤ ± 2	≤ 3.5	≤ 3.5	≤ 3.5	≤ 3.5	≤ 3.5
run0	1.9	0.8	0.7	-0.2	0.0	2.4	4.6	5.0	1.3	0.8
run1	3.1	2.2	4.4	0.0	-0.3	3.8	2.2	4.4	0.7	0.8

Tables 5-4 through 5-6 show similar statistics for humidity, wind speed and wind direction, respectively. Run1 shows substantially better bias and error statistics for humidity (Table 5-4) during the July 1-2 period. The positive biases in run0 (July 1: +1.0 g/kg; July 2: +2.6 g/kg) result from overactive convection in the LVV, which is corroborated by the time series and precipitation analyses discussed later. Aside from July 1 (+0.2 g/kg), run1 exhibits negative mixing ratio biases on July 2 (-3.2 g/kg) and for the other 3 days. Despite these rather substantial dry biases, run1 results in better agreement with observed precipitation and near-surface temperature during this period.

Run1 exhibits generally better or similar wind speed (Table 5-5) bias and RMSE for June 30 – July 2, though the statistical differences from run0 are not large. Relative performance for wind direction (Table 5-6) is mixed and no clear conclusions can be drawn from the statistics alone. We also note that observed wind direction is flagged as missing (and therefore hourly statistics are not calculated) at low/variable wind speeds and these occurrences are generally more frequent during high ozone periods.

Table 5-4. Daily water vapor mixing ratio bias and error statistics for EPA WRF run0 and Ramboll WRF run1 for June 30 – July 4, 2016 across the LVV. Bold text indicates statistics meeting complex benchmarks, while green highlighted cells show days where run1 outperforms run0.

	Mean Bias (g/kg)					Mean Error (g/kg)				
	6/30	7/01	7/02	7/03	7/04	6/30	7/01	7/02	7/03	7/04
Benchmark	≤ ± 1	≤ ± 1	≤ ± 1	≤ ± 1	≤ ± 1	≤ 2	≤ 2	≤ 2	≤ 2	≤ 2
run0	0.7	1.0	2.6	-0.7	-1.0	1.8	1.4	3.0	1.7	1.0
run1	-0.8	0.2	-3.2	-4.8	-2.5	1.9	0.8	3.3	4.8	2.5

Table 5-5. Daily wind speed bias and error statistics for EPA WRF run0 and Ramboll WRF run1 for June 30 – July 4, 2016 across the LVV. Bold text indicates statistics meeting complex benchmarks, while green highlighted cells show days where run1 outperforms run0.

	Mean Bias (m/s)					RMSE (m/s)				
	6/30	7/01	7/02	7/03	7/04	6/30	7/01	7/02	7/03	7/04
Benchmark	≤ ±1.5	≤ ±1.5	≤ ±1.5	≤ ±1.5	≤ ±1.5	≤ 2.5	≤ 2.5	≤ 2.5	≤ 2.5	≤ 2.5
run0	-1.0	-1.6	-1.2	-0.4	-0.5	3.3	3.6	2.8	1.4	1.5
run1	-0.2	-0.8	1.2	0.9	-0.2	3.3	2.9	3.1	1.8	2.1

Table 5-6. Daily wind direction bias and error statistics for EPA WRF run0 and Ramboll WRF run1 for June 30 – July 4, 2016 across the LVV. Bold text indicates statistics meeting complex benchmarks, while green highlighted cells show days where run1 outperforms run0.

	Mean Bias (m/s)					Mean Error (m/s)				
	6/30	7/01	7/02	7/03	7/04	6/30	7/01	7/02	7/03	7/04
Benchmark	≤ ±10	≤ ±10	≤ ±10	≤ ±10	≤ ±10	≤ 55	≤ 55	≤ 55	≤ 55	≤ 55
run0	8	-17	32	11	11	64	84	98	44	30
run1	26	46	19	13	13	75	73	74	47	34

5.5.2 Time Series Comparison

Figure 5-20 shows time series at KLAS for WRF run0 (red), WRF run1 (blue) and observations (black) for 2-m temperature (1st panel from top), 2-m water vapor mixing ratio (2nd panel), 10-m wind speed (3rd panel) and 10-m wind direction (bottom panel) during June 30 – July 4, 2016. On June 30, apparent convective activity is reflected in the KLAS observations, with a sudden temperature drop around midday paired with spikes in observed mixing ratio. Run0 appears to capture the timing of the onset of convective activity as evidenced by the concurrent sharp temperature decrease and mixing ratio increase. However, run0 temperatures quickly rebound (while mixing ratio decreases), signifying an end to shower activity in the model, which contrasts with the observations that support continued shower activity in the region (temperature continues to drop while mixing ratio spikes). Run1 performs worse than run0 on June 30, with midday peak temperatures substantially overestimated (and mixing ratio underestimated) with no obvious daytime convective signal as seen in the observations and run0.

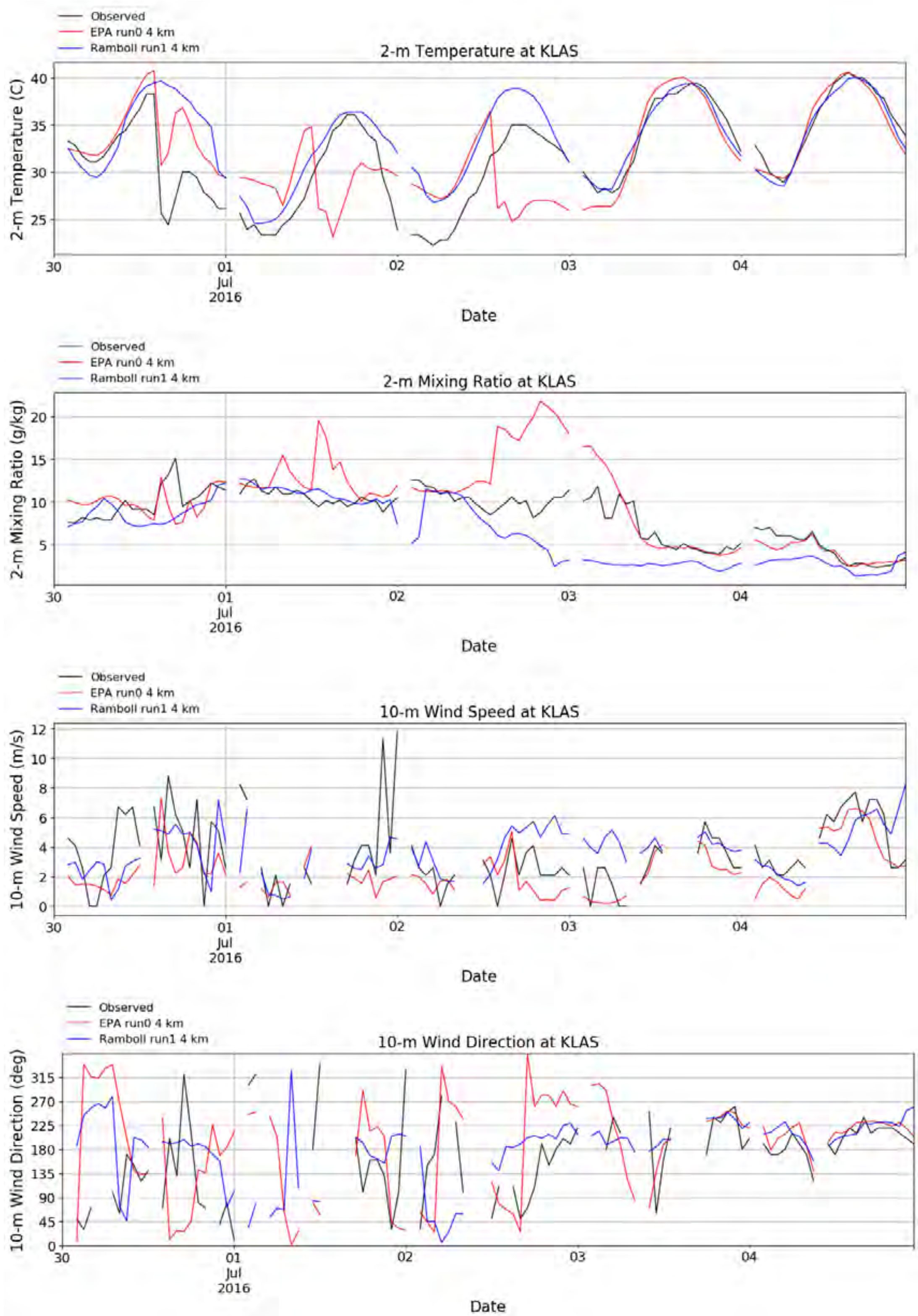


Figure 5-20. Observed (black line), EPA WRF run0 (red) and Ramboll WRF run1 (blue) 2-m temperature (first panel from top), 2-m water vapor mixing ratio (second panel), 10-m wind speed (third panel) and 10-m wind direction (bottom panel) time series for June 30 – July 4, 2016 at KLAS.

On July 1 and 2, run0 again shows daytime temperature crashes paired with large spikes in mixing ratio, indicating convective activity that does not occur in the observations. We verified that these convective events result in dramatic collapses in mixing depth, which have implications for ozone modeling in CAMx. Run1 does not exhibit such convective activity on July 1 and 2 and matches the midday temperature peak reasonably well on July 1. Overnight temperatures into July 2 for run1 remain considerably higher than observed and this positive temperature bias persists into midday, where the run1 daytime peak is about 4° C higher than observed. At the same time, run1 mixing ratio begins a downward trend around midday on July 2 leading to substantial negative biases through July 4. Temperature performance is similar between the two runs for July 3 and 4, with run1 matching observations slightly better than run0.

Wind speed and wind direction time series show no clear winner and there are many missing observations during the July 1-2 high ozone period, apparently due to calm/variable winds below measurement thresholds. From these results, we were confident that replacing run0 meteorology with run1 would not substantially degrade wind performance during the July 1-2 high ozone period.

5.5.3 Vertical Profile Comparisons

Figures 5-21 through 5-29 show vertical profiles of WRF (blue) and observed (red) temperature (soild lines) and dewpoint temperature (dashed lines) at 00Z and 12Z (5 AM and PM PDT) at the KVEF RAOB from June 30, 2016 at 5 AM PDT (Figure 5-21) through July 4, 2016 at 5 AM PDT (Figure 5-29). Solid lines in the left panels show WRF run0 profiles and solid lines in the right panels show WRF run1 profiles. The first two figures spanning June 30 (Figure 5-21 and 5-22) show that WRF run0 better matches the observed profiles than run1, but the differences are not substantial. On July 1 (Figures 5-23 and 5-24), large differences build; run0 substantially underpredicts afternoon near-surface temperature, while run1 matches the observations quite well for both temperature and dewpoint. On July 2 at 5 AM PDT (Figure 5-25), model differences decrease, and both runs show similar positive temperature biases near the surface while matching the observed dewpoint quite well. On that afternoon, however, near-surface temperatures in run0 (Figure 5-26) again exhibit a substantial underestimate, while run1 shows a smaller temperature overestimate coupled with a much drier profile than observed. Both runs do a better job matching the observed temperature profiles through the remaining soundings covering July 3 and 4, while run1 continues the trend toward much drier profiles than observed.

5.5.4 Qualitative Evaluation for Precipitation

Figure 5-30 shows the precipitation patterns from PRISM based on observations (left) and modeled by WRF run0 (middle) and run1 (right) for the 24-hour period ending July 1, 2016 at 5 AM PDT. PRISM shows lighter rain amounts (< 0.1 inches) in the northern LVV and heavier amounts to the south, including a local maximum surrounding KLAS and KHND, with over 0.5 inches. Both WRF runs show similar patterns to each other, with a general underestimate of precipitation in the LVV and overestimates to the east.

Figure 5-31 shows the same information ending on July 2, 2016 at 5 AM PDT. WRF run0 does a reasonable job matching the magnitude of PRISM precipitation amounts in the LVV. Because the time series show signatures of overstated precipitation (sudden increases in mixing ratio paired with sudden decreases in temperature relative to observations), we conclude that run0 produces precipitation at spurious times/locations during the day. Run1 is mostly dry throughout the LVV (right panel of Figure 5-31).

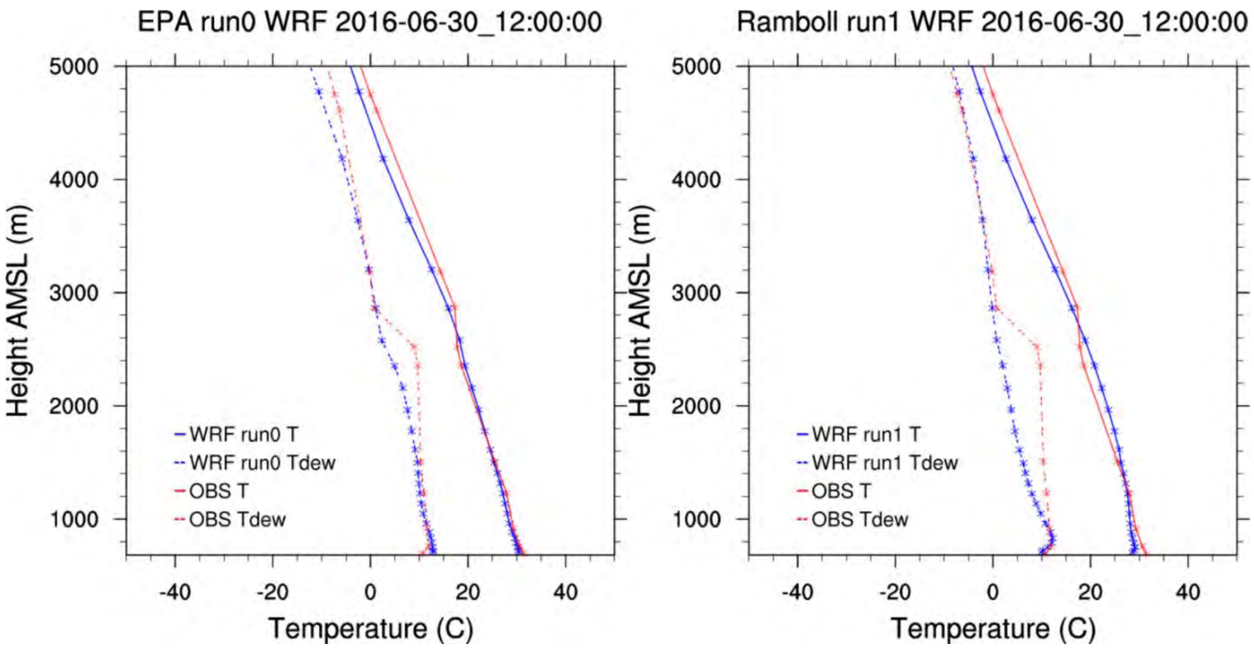


Figure 5-21. Vertical profiles at KVEF from WRF run0 (blue lines in left panel), WRF run1 (blue lines in right panel) and observed (red) temperature (solid lines) and dewpoint temperature (dashed lines) on June 30, 2016 at 5 AM PDT.

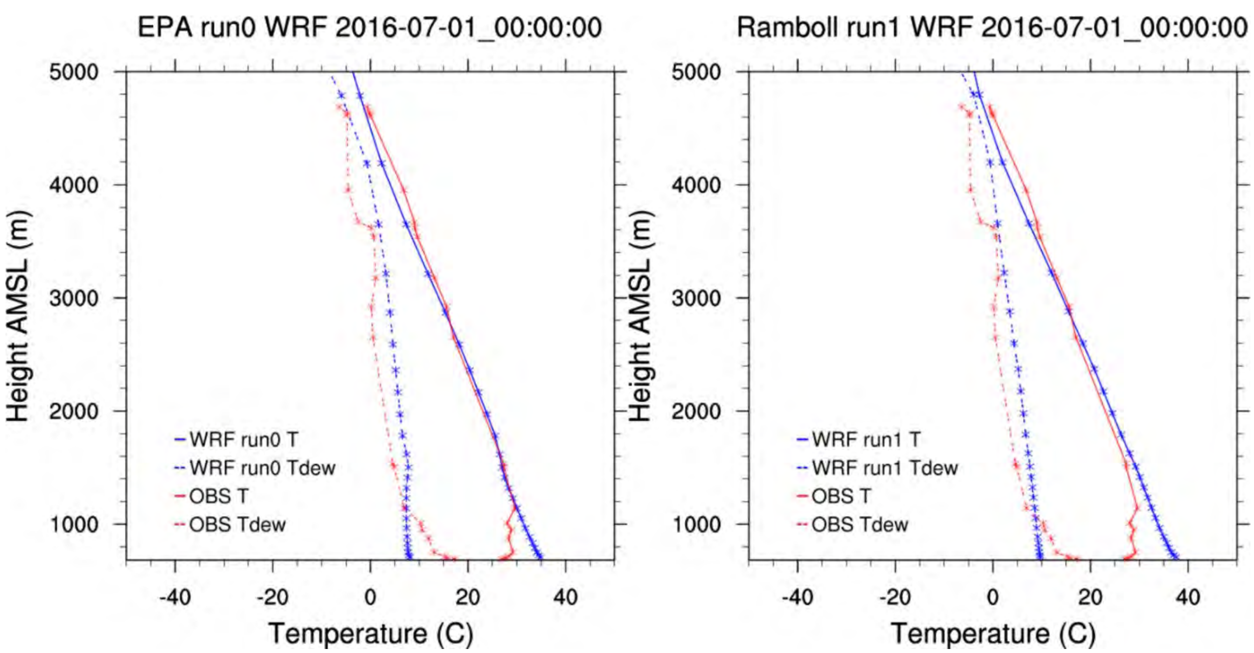


Figure 5-22. Vertical profiles at KVEF from WRF run0 (blue lines in left panel), WRF run1 (blue lines in right panel) and observed (red) temperature (solid lines) and dewpoint temperature (dashed lines) on June 30, 2016 at 5 PM PDT.

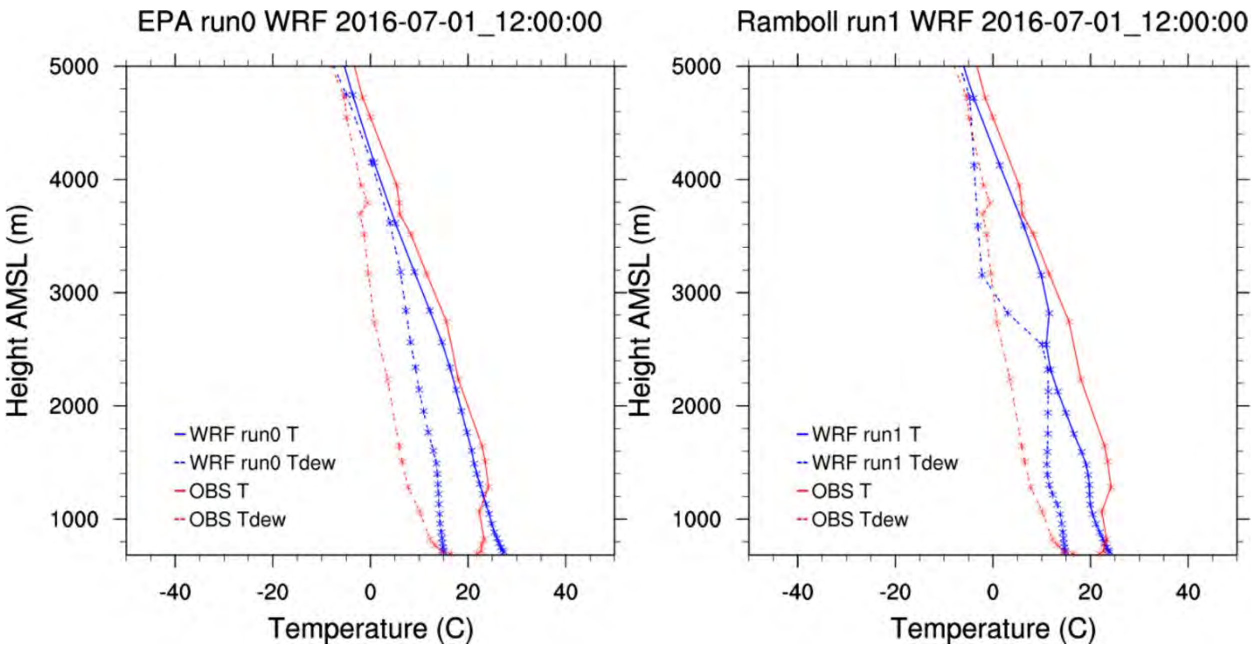


Figure 5-23. Vertical profiles at KVEF from WRF run0 (blue lines in left panel), WRF run1 (blue lines in right panel) and observed (red) temperature (solid lines) and dewpoint temperature (dashed lines) on July 1, 2016 at 5 AM PDT.

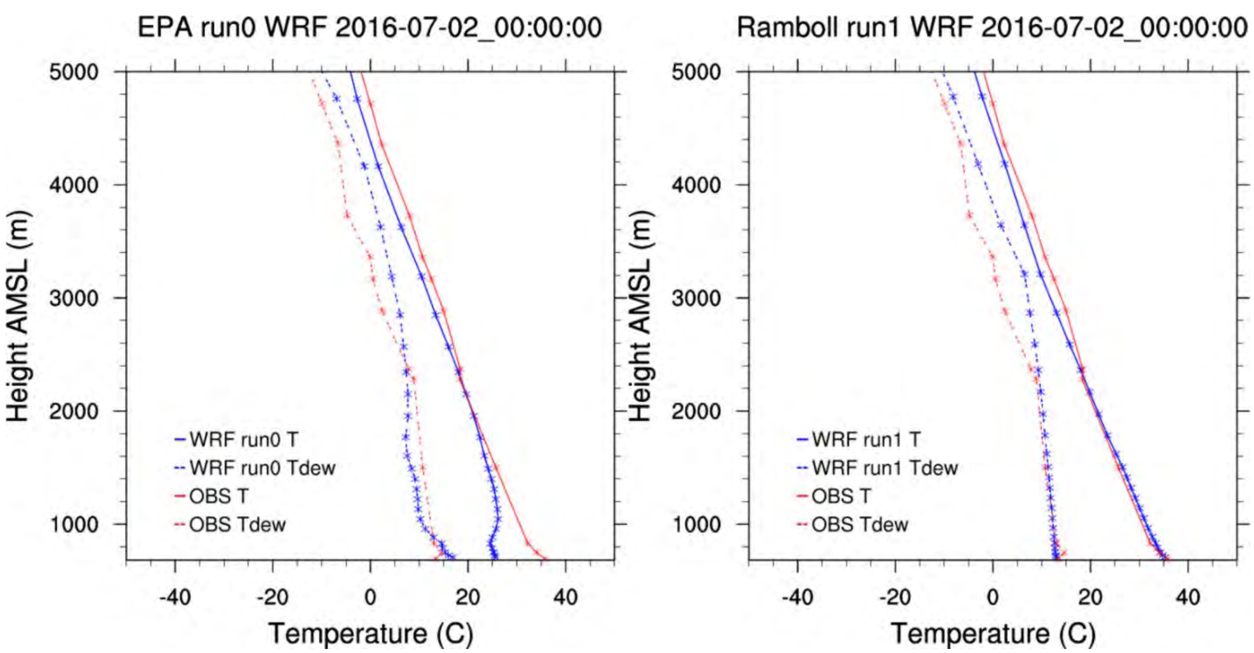


Figure 5-24. Vertical profiles at KVEF from WRF run0 (blue lines in left panel), WRF run1 (blue lines in right panel) and observed (red) temperature (solid lines) and dewpoint temperature (dashed lines) on July 1, 2016 at 5 PM PDT.

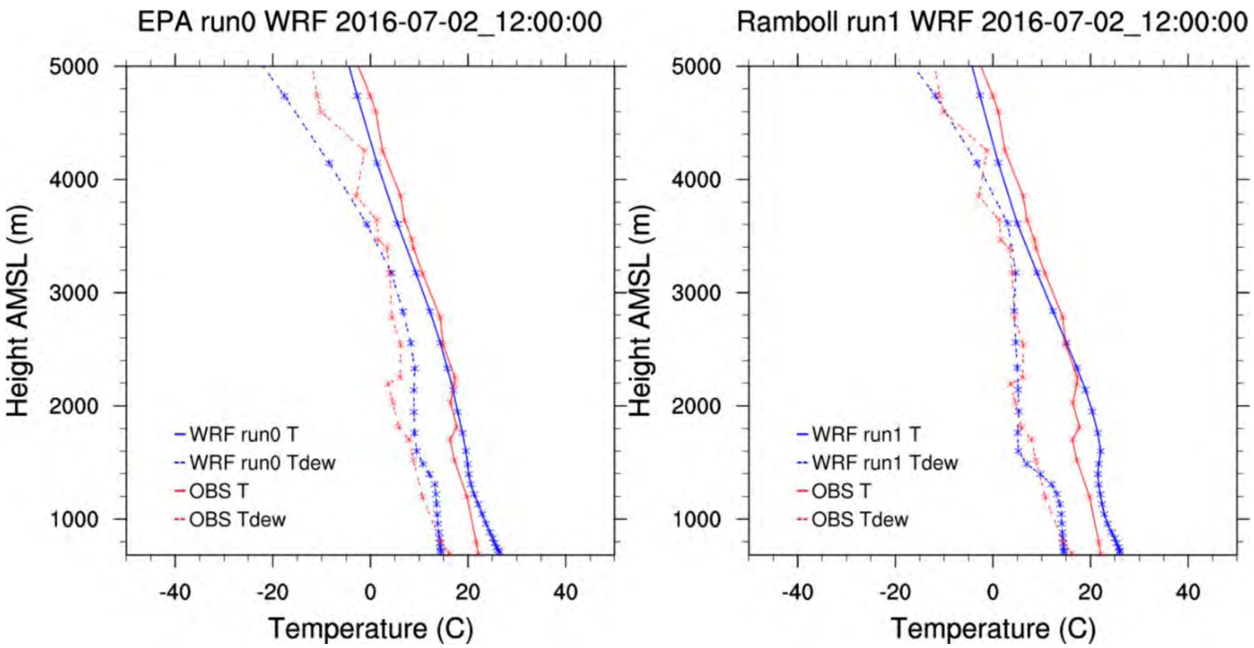


Figure 5-25. Vertical profiles at KVEF of WRF run0 (blue lines in left panel), WRF run1 (blue lines in right panel) and observed (red) temperature (solid lines) and dewpoint temperature (dashed lines) on July 2, 2016 at 5 AM PDT.

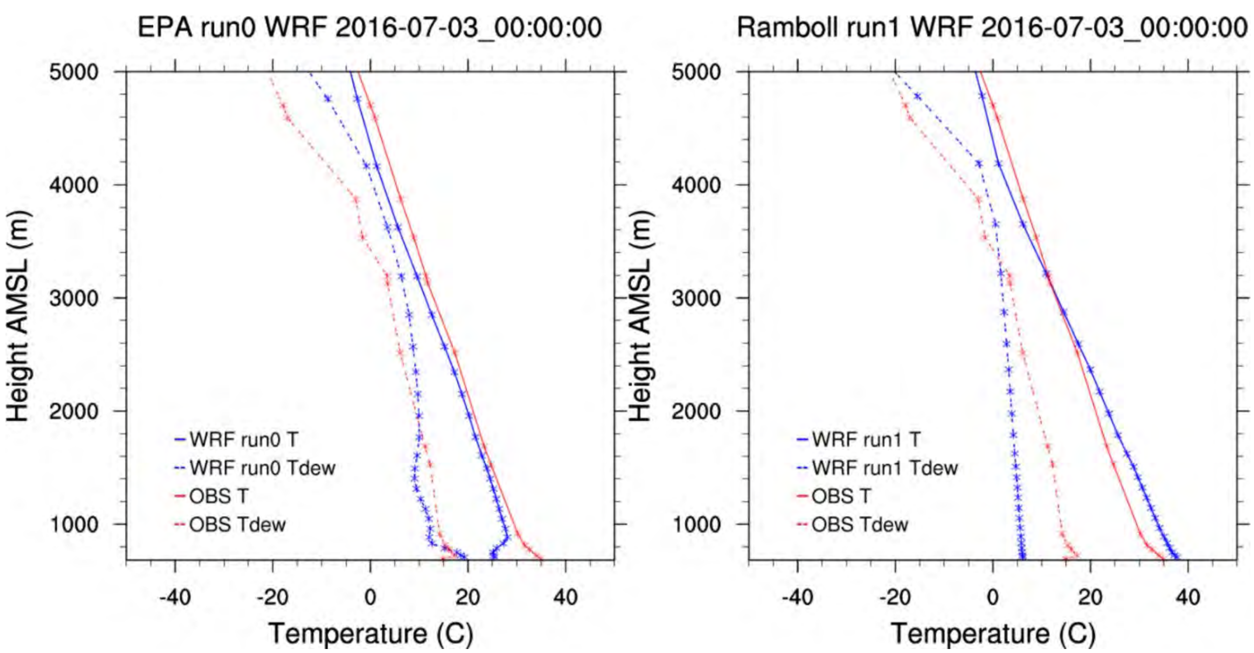


Figure 5-26. Vertical profiles at KVEF from WRF run0 (blue lines in left panel), WRF run1 (blue lines in right panel) and observed (red) temperature (solid lines) and dewpoint temperature (dashed lines) on July 2, 2016 at 5 PM PDT.

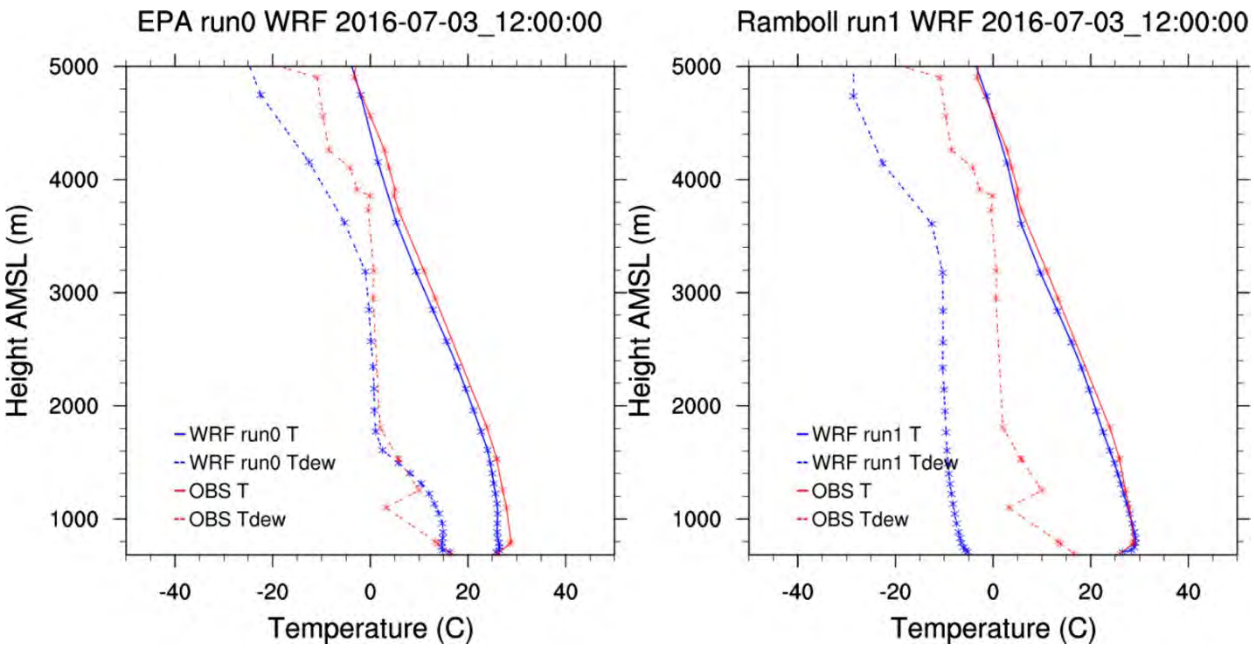


Figure 5-27. Vertical profiles at KVEF from WRF run0 (blue lines in left panel), WRF run1 (blue lines in right panel) and observed (red) temperature (solid lines) and dewpoint temperature (dashed lines) on July 3, 2016 at 5 AM PDT.

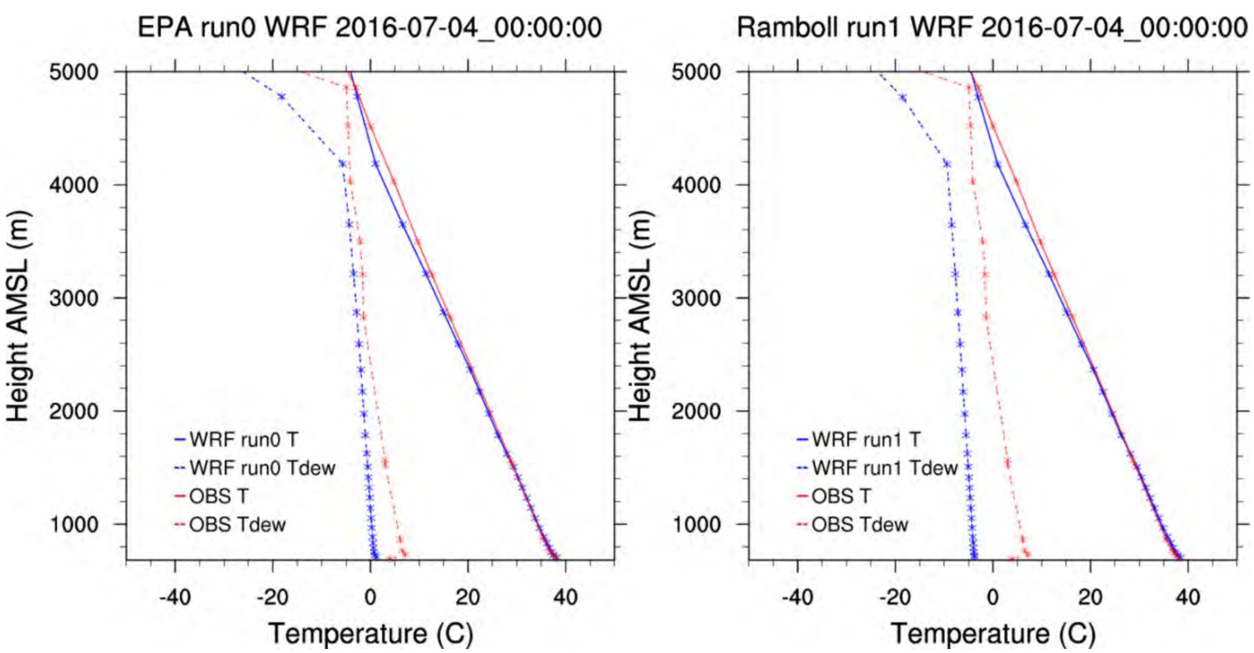


Figure 5-28. Vertical profiles at KVEF from WRF run0 (blue lines in left panel), WRF run1 (blue lines in right panel) and observed (red) temperature (solid lines) and dewpoint temperature (dashed lines) on July 3, 2016 at 5 PM PDT.

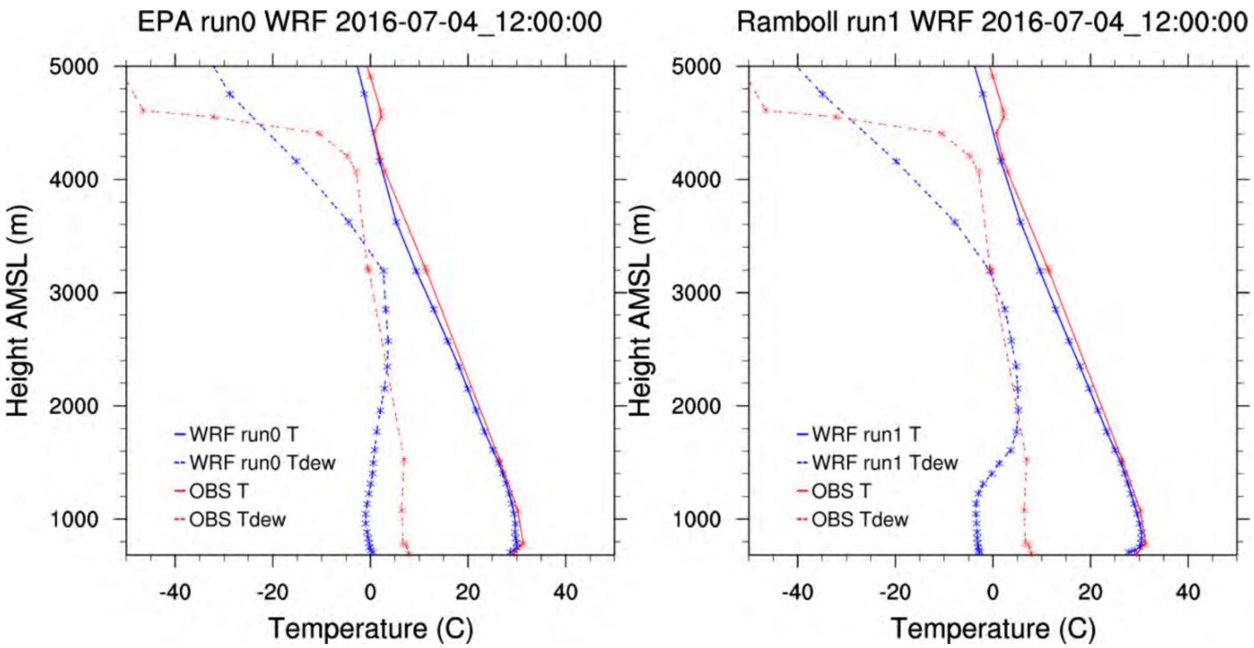


Figure 5-29. Vertical profiles at KVEF from WRF run0 (blue lines in left panel), WRF run1 (blue lines in right panel) and observed (red) temperature (solid lines) and dewpoint temperature (dashed lines) on July 4, 2016 at 5 AM PDT.

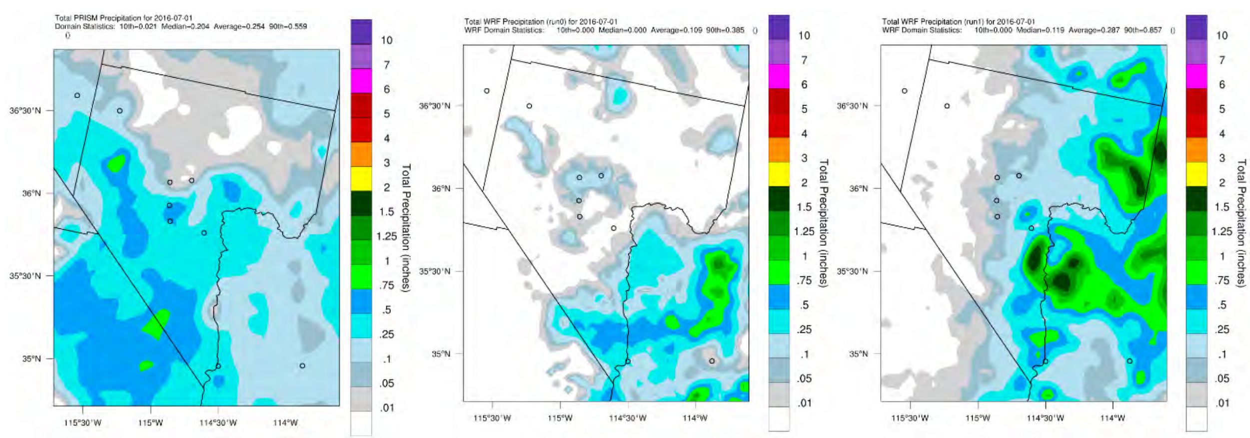


Figure 5-30. Precipitation patterns from PRISM based on observations (left) and modeled by EPA WRF run0 (middle) and Ramboll WRF run1 (right) for the 24-hour period ending July 1, 2016 at 5 AM PDT.

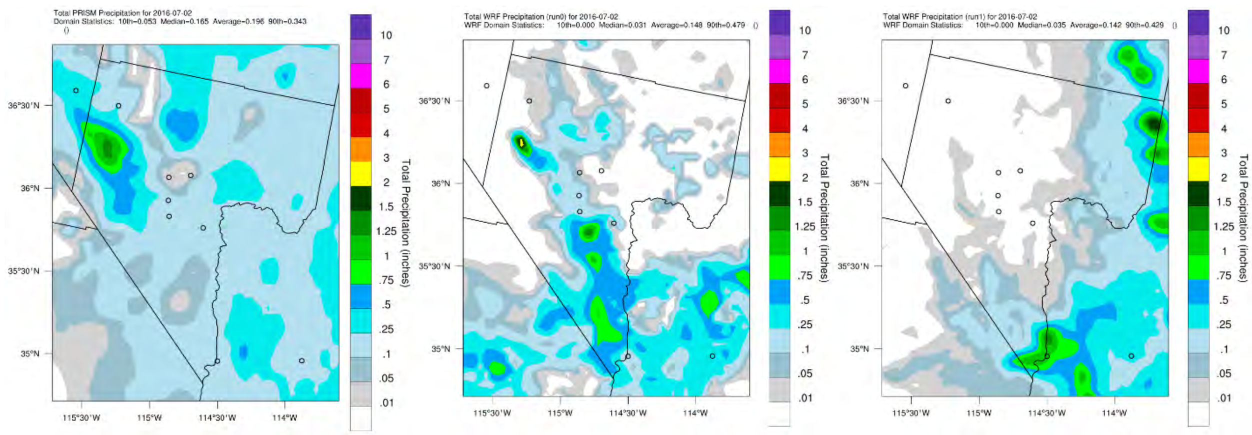


Figure 5-31. Precipitation patterns from PRISM based on observations (left) and modeled by EPA WRF run0 (middle) and Ramboll WRF run1 (right) for the 24-hour period ending July 2, 2016 at 5 AM PDT.

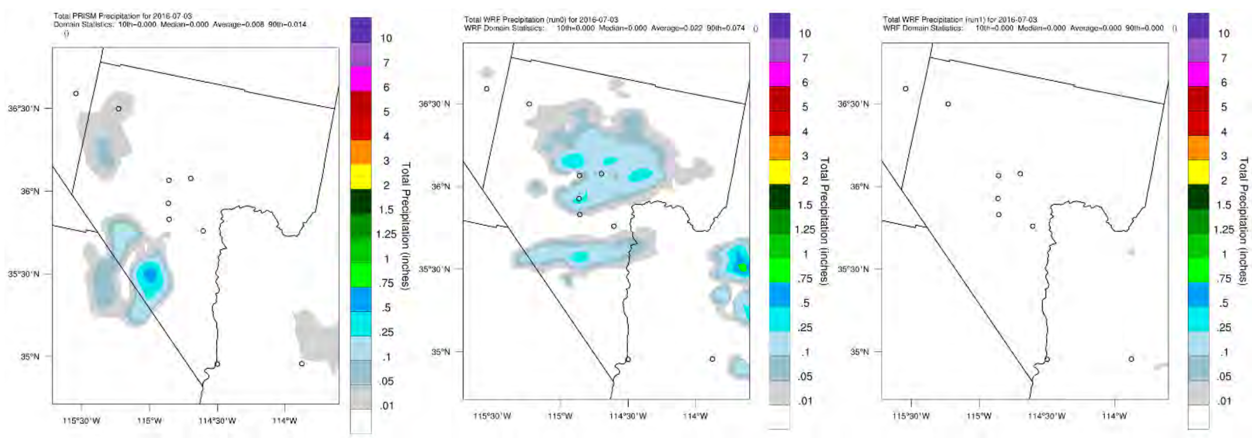


Figure 5-32. Precipitation patterns from PRISM based on observations (left) and modeled by EPA WRF run0 (middle) and Ramboll WRF run1 (right) for the 24-hour period ending July 3, 2016 at 5 AM PDT.

Finally, Figure 5-32 shows the same information ending July 3, 2016 at 5 AM PDT. PRISM shows the LVV as mostly dry during this period, while run0 continues to generate several local showers throughout the LVV with rain amounts exceeding 0.25 inches. By contrast, run1 shows no precipitation in the LVV, in better agreement with PRISM. We exclude PRISM precipitation plots for July 3-4 due to near-zero precipitation in PRISM and zero precipitation across the domain in both run0 and run1.

5.5.5 Phenomenological Evaluation

Figure 5-33 shows a comparison of the 700 mb upper air analysis chart (left panel; height contours in grey; temperature contours shown as red dashed lines; dewpoint temperatures exceeding -4°C shown as green lines) and 700 mb WRF 4 km run0 (center) and WRF 4 km run1 (right) height contours (purple), wind vectors and temperature on July 1, 2016 at 5 PM PDT. The orientation of both WRF run0 and WRF run1 height contours generally agree with those shown on the analysis chart, which indicates a broad region of flat height gradient and weak winds surrounding a weak upper-level low pressure system. Similarly, WRF run0 and WRF run1 wind speed and direction tend to agree qualitatively with the upper air stations. The evaluation of WRF run0 and run1 at specific locations in the LVV reveal discernable performance differences on this day. Because the large-scale features seem to be represented reasonably well in both WRF simulations, we conclude that these performance differences are primarily due to mesoscale and local scale influences (e.g., convection and interactions with elevated terrain, which influence winds at 700 mb) given the rather weak synoptic scale patterns.

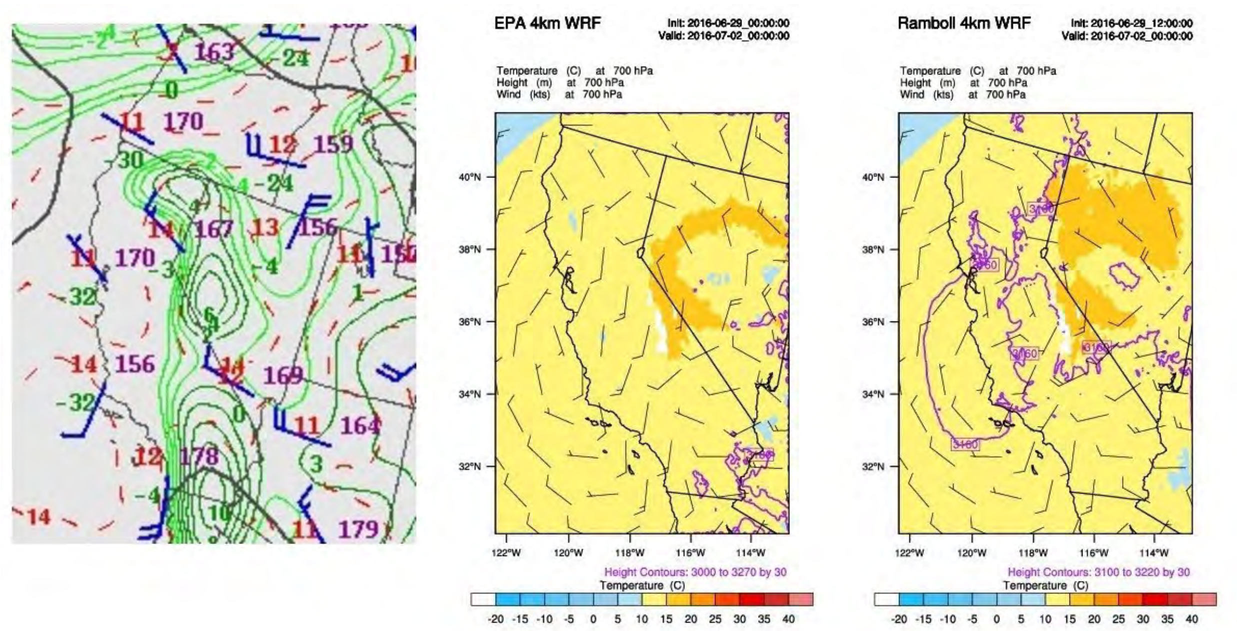


Figure 5-33. Left panel: 700 mb upper air analysis chart (height contours in grey; temperature contours shown as red dashed lines; dewpoint temperatures exceeding -4° C shown as green lines). Center panel: 700 mb WRF 4 km run0 height contours (purple), wind vectors and temperature. Right panel: same as center panel but for WRF 4 km run1. All panels show results for July 1, 2016 at 5 PM PDT.

6.0 BASE AND FUTURE YEAR EMISSION INPUTS

6.1 Emissions Data and Methods

The EPA recently developed the 2016v2 emissions modeling platform (EMP)[14], which includes a full suite of the base year (2016) and future year inventories, ancillary emissions data, and scripts and software for preparing emissions to support air quality modeling. The 2016v2 EMP incorporates emissions based on the updated MOVES3 mobile source model, the 2017 NEI non-point inventory, the WRAP oil and gas inventory, and updated inventories for Canada and Mexico. In addition, the 2016v2 EMP uses a new approach and data to estimate emissions for VCPs implemented in the VCPy framework (Seltzer et al., 2021). For this project, the EMP's 2016fj and 2023fj emission inventories were the primary sources of the CAMx emission inputs (EPA, 2022b)[15]. However, locally specific emissions data from Clark County were used for the CC4c2 modeling domain wherever feasible.

CAMx requires hourly emissions of both anthropogenic and natural sources that have been spatially allocated to the modeling grid cells and chemically speciated for the Carbon Bond version 6 (CB6; Ramboll, 2022b) chemical mechanism used in the model. The anthropogenic source categories include stationary point sources, stationary non-point (area) sources, on-road mobile sources, non-road mobile sources, airports, locomotives, ocean-going vessels, and agricultural sources. The natural sources include biogenic, lightning, oceanic, and wildfires. We processed and prepared the modeling emissions for CAMx using EPA's SMOKE software, version 4.8.1 (UNC, 2020). The sections below describe the development of the 2016 Base Case and 2023 Future Year emission inputs for CAMx modeling.

6.1.1 2016 Base Case Emissions

The sources of 2016 Base Case emissions data for each source category and each grid are presented in Table 6-1. For the 36US3 and 12US2 domains, 2016v2 CMAQ-ready emission inputs were simply converted to CAMx formats using the CMAQ2CAMx processor. Ramboll has previously conducted extensive quality assurance evaluations on these files to ensure proper conversion without loss or gain of emissions and proper formatting. These emission files have been, and continue to be, used extensively by Ramboll in other projects.

For the CC4c2 domain, the 2016fj inventory served as the primary source of emission inputs, augmented with locally specific data for airports and on-road mobile sectors provided by the Clark County DES/DAQ. Ramboll applied EPA's standard 4 km US-wide spatial surrogates to facilitate grid allocation, which EPA developed on the same Lambert map projection and grid system as their 2016 MP and thus exactly aligns with the CC4c2 grid definition. Development of the 2016 CC4c2 domain anthropogenic emission inputs is summarized below:

- On-road mobile source emissions were developed using the SMOKE-MOVES processor with:
  (1) 2016 emission factors generated by EPA's MOVES3 run provided by the 2016v2 EMP;
  (2) County-level vehicle activity data from the 2016v2 EMP; and
  (3) CC4c2 gridded hourly WRF meteorological data.
- Non-road emissions were developed from the 2016v2 EMP using SMOKE.
- 2016fj point source electric generating unit (EGU) emissions included hourly 2016 Continuous Emissions Monitoring System (CEMS) values for NOx and SO_2.

[14] https://www.epa.gov/air-emissions-modeling/2016v2-platform

[15] Technical Support Document: https://www.epa.gov/system/files/documents/2022-02/2016v2_emismod_tsd_february2022.pdf

Table 6-1. Sources of 2016 Base Case inventory sectors by domain.

Source Category	CC4c2 (Clark County 4 km Domain)	12US2 (12 km Domain)	36US3 (36 km Domain)
Area: *ag, rwc, afdust, nonpt, solvents*	EPA 2016fj inventory	EPA 2016fj model-ready files	EPA 2016fj model-ready files
Oil & Gas: *np_oilgas, pt_oilgas*	N/A	EPA 2016fj model-ready files	EPA 2016fj model-ready files
On-road Mobile: *onroad*	SMOKE-MOVES with EPA 2016fj MOVES3 emission factors, VMT, vehicle population and CC4c2 MCIP met.	EPA 2016fj model-ready files	EPA 2016fj model-ready files
Non-road: *Nonroad*	EPA 2016fj inventory	EPA 2016fj model-ready files	EPA 2016fj model-ready files
Airports: *airports*	2017 airport emissions provided by Clark County	EPA 2016fj model-ready files	EPA 2016fj model-ready files
CMV: *cmv_c1c2, cmv_c3*	N/A	EPA 2016fj model-ready files	EPA 2016fj model-ready files
Locomotives: *rail*	EPA 2016fj inventory	EPA 2016fj model-ready files	EPA 2016fj model-ready files
EGU Point: *ptegu*	EPA 2016fj model-ready files: all emissions in this sector are elevated (no low-level contribution)	EPA 2016fj model-ready files	EPA 2016fj model-ready files
Point: *ptnonipm*	EPA 2016fj model-ready files: all emissions in this sector are elevated (no low-level contribution)	EPA 2016fj model-ready files	EPA 2016fj model-ready files
Non-US: *Canada/Mexico/Offshore*	N/A	EPA 2016fj model-ready files	EPA 2016fj model-ready files
Fires	EPA 2016fj PTFIRE3D model-ready files	EPA 2016fj PTFIRE3D model-ready files	EPA 2016fj PTFIRE3D model-ready files
Biogenic	2016 BEIS4/BELD6 with CC4c2 MCIP met	2016 BEIS4/BELD6 with 12US2 MCIP met	2016 BEIS4/BELD6 with 36US3 MCIP met
Lightning NOx	12-km virtual point sources from Ramboll's LNOx processor and EPA 2016 12US2 WRF meteorology		N/A

- Non-point emissions from the EPA 2016v2 EMP were processed with SMOKE. The non-point source category includes area-wide residential, commercial, and industrial emissions, VCPs, agricultural sources, and other non-point sectors. As noted above, the 2016v2 EMP used a new approach and data to estimate emissions for VCP sources. EPA back-casted all other non-point emissions inputs from the 2017 NEI to the year 2016.
- The Clark County Department of Aviation (DOA) provided 2017 emissions for commercial aviation, which includes Harry Reid (McCarran) International Airport, North Las Vegas Airport, and Henderson Executive Airport. Federal aviation emissions consist entirely of emissions from Nellis Air Force Base (NAFB), which provided 2017 emissions to DES/DAQ. The 2017 emissions from aircraft operations were used directly for the 2016 Base Case and processed with SMOKE.

6.1.2 Biogenic Emissions

Biogenic VOC and NOx emissions were initially based on BEIS3.7 to be consistent with the EPA 2016v2 MP. BEIS is built into SMOKE and can be downloaded from the SMOKE website. The inputs to BEIS include: (1) landcover distributions that define emission factors according to biomass type, and (2) gridded hourly meteorology as biogenic VOC emissions are sensitive to temperature and solar radiation. BEIS3.7 was used in conjunction with the Biogenic Landcover Database version 5 (BELD5) and gridded hourly meteorology from the WRF 2016 simulation as described in Section 5. BELD5 data are provided by EPA covering the entire US at 4-km grid scale that exactly matches the 12US2 mapping conventions and the CC4c2 grid specifications. Therefore, no special mapping of BELD5 data to the CC4c2 grid was necessary.

BEIS3.6/BELD4, BEIS4/BELD6, and MEGAN3.2 were later evaluated as alternatives for CAMx sensitivity testing (see Section 8.4). Each of these models resulted in substantially different estimates in biogenic VOC emissions in Clark County. While modeled biogenic NOx and VOC emission rates have trended downward with succeeding versions from BEIS3.6 to BEIS4, the huge range of emission rates among these versions illustrates the remaining uncertainty in desert biogenic emission estimates and related vegetative characterization over just the last few years. Most notably, VOC emissions varied by nearly 1000-fold between BEIS3.6 and MEGAN3.2. Ultimately, we replaced BEIS3.7/BELD5 with the latest BEIS4/BELD6 biogenic emissions platform, which reduced both rural and urban isoprene emissions below both of its predecessors, in agreement with reports from EPA's early testing for the western US (Ramboll, 2022c). EPA graciously processed BELD6 vegetative cover datasets for the 12US2 and CC4c2 grids for our use with BEIS4. Ramboll processed BEIS4 biogenic emissions on the 36US3/12US2/CC4c2 grid system for the entirety of the April-August modeling period.

Table 6-2 lists 2016 summer monthly average biogenic emissions (TPD) on the CC4c2 grid as determined from the four different biogenic emission platforms. Section 8.4.10 provides additional details on biogenic emission comparisons and modeling results.

6.1.3 Other Natural Source Emissions

EPA did not develop NOx emissions from lightning for their 2016v2 MP. Therefore, Ramboll independently developed lightning NOx emissions using a CAMx processor called LNOx available from the CAMx website[16]. The LNOx processor uses WRF output fields defining convective activity (cloud top heights and convective available potential energy) to determine location, timing, and frequency of lightning to generate three-dimensional NOx emissions. LNOx emissions are developed as virtual point sources.

[16] https://www.camx.com/download/support-software/

Table 6-2. 2016 summer monthly biogenic emissions (TPD) estimated for the CC4c2 modeling domain from four biogenic modeling systems.

Biogenic Model	May	June	July	August	Average
	NOx				
BEIS3.6/BELD4 (2016v1)	6	9	9	9	8
BEIS3.7/BELD5 (2016v2)	5	7	8	7	7
BEIS4/BELD6	5	7	8	7	7
MEGAN3.2	17	32	30	27	27
Biogenic Model	VOC				
BEIS3.6/BELD4 (2016v1)	850	1,936	2,128	1,737	1,663
BEIS3.7/BELD5 (2016v2)	288	654	717	586	561
BEIS4/BELD6	71	154	167	139	133
MEGAN3.2	2	3	15	26	12
Biogenic Model	Isoprene				
BEIS3.6/BELD4 (2016v1)	145	294	304	258	250
BEIS3.7/BELD5 (2016v2)	57	114	118	101	97
BEIS4/BELD6	13	23	22	20	19
MEGAN3.2	1	1	7	2	3
Biogenic Model	Terpene				
BEIS3.6/BELD4 (2016v1)	253	582	653	534	505
BEIS3.7/BELD5 (2016v2)	64	148	165	135	128
BEIS4/BELD6	16	36	40	33	31
MEGAN3.2	1	1	4	2	2

Given potentially very different meteorological realizations of convective activity between the 12US2 and CC4c2 grids (as described in Section 5 for July 1-2), we adopted 12US2 LNOx emissions developed previously for another Ramboll project, which were based on EPA's WRF data. As grid-independent point sources, LNOx emits into both the 12US2 and CC4c2 grids. LNOx data are sparse in time and space and therefore the use of 12 km LNOx emissions within the CC4c2 grid does not materially affect the CC4c2 ozone results.

Open land fires (e.g., wildfires) were based on the EPA 2016v2 inventory. For fires within the United States, EPA estimated emissions using the Satellite Mapping Automated Reanalysis Tool for Fire Incident Reconciliation version 2 (SMARTFIRE2) and the BlueSky Framework (EPA, 2022b). EPA developed fire emissions from outside of the United States using the Fire Inventory from NCAR (FINN[17]). The 2016v2 platform provides three-dimensional layered CMAQ model-ready fire emissions with plume rise calculated by SMOKE. These emission files were converted into CAMx point format using the CMAQ2CAMx converter, which retained the layer-by-layer distribution of smoke emissions.

6.2 2023 Future Case Emissions

The procedures used to develop the Clark County CAMx 2023 emission inputs were similar to those for the 2016 Base Case. The sources of 2023 Future Case emissions data for each source category and each grid are presented in Table 6-3.

[17] https://www2.acom.ucar.edu/modeling/finn-fire-inventory-ncar.

Table 6-3. Sources of 2023 Future Year inventory sectors by domain.

Source Category	CC4c2 (Clark County 4 km Domain)	12US2 (12 km Domain)	36US3 (36 km Domain)
Area: *ag, rwc, afdust, nonpt, solvents*	EPA 2023fj inventory	EPA 2023fj model-ready files	EPA 2023fj model-ready files
Oil & Gas: *np_oilgas, pt_oilgas*	N/A	EPA 2023fj model-ready files	EPA 2023fj model-ready files
On-road Mobile: *onroad*	SMOKE-MOVES with EPA 2023fj MOVES3 emission factors, Clark County VMT, vehicle population and CC4c2 MCIP met.	EPA 2023fj model-ready files	EPA 2023fj model-ready files
Non-road: *Nonroad*	EPA 2023fj inventory	EPA 2023fj model-ready files	EPA 2023fj model-ready files
Airports: *airports*	2023 airport emissions provided by Clark County	EPA 2023fj model-ready files	EPA 2023fj model-ready files
CMV: *cmv_c1c2, cmv_c3*	N/A	EPA 2023fj model-ready files	EPA 2023fj model-ready files
Locomotives: *rail*	EPA 2023fj inventory	EPA 2023fj model-ready files	EPA 2023fj model-ready files
EGU Point: *ptegu*	EPA 2023fj model-ready files: all emissions in this sector are elevated (no low-level contribution)	EPA 2023fj model-ready files	EPA 2023fj model-ready files
Point: *ptnonipm*	EPA 2023fj model-ready files: all emissions in this sector are elevated (no low-level contribution)	EPA 2023fj model-ready files	EPA 2023fj model-ready files
Non-US: *Canada/Mexico/Offshore*	N/A	EPA 2023fj model-ready files	EPA 2023fj model-ready files
Fires	EPA 2016fj PTFIRE3D model-ready files	EPA 2016fj PTFIRE3D model-ready files	EPA 2016fj PTFIRE3D model-ready files
Biogenic	2016 BEIS4/BELD6 with CC4c2 MCIP met	2016 BEIS4/BELD6 with 12US2 MCIP met	2016 BEIS4/BELD6 with 36US3 MCIP met
Lightning NOx	12-km virtual point sources from Ramboll's LNOx processor and EPA 2016 12US2 WRF meteorology		N/A

The 2023 36US3 and 12US2 emissions were based on EPA's CMAQ-ready 2023fj emissions, converted to CAMx using the CMAQ2CAMx processor. Natural emissions and fires were held constant at 2016 values. Development of the 2023 CC4c2 domain anthropogenic emission inputs is summarized below:

- On-road mobile source emissions were developed using the SMOKE-MOVES processor using:
  (1) 2023 emission factors generated by EPA's MOVES3 run provided by the 2016v2 EMP;
  (2) Clark County 2023 vehicle miles traveled (VMT) and vehicle population data provided by DES/DAQ based on travel demand modeling;
  (3) Clark County 2023 vehicle starts and hours of off-network idling calculated using VMT ratios;
  (4) 2023 county-level vehicular activity data for all other counties from the 2016v2 EMP; and
  (5) CC4c2 gridded hourly WRF meteorological data.
- Non-road emission inputs were developed from the 2016v2 EMP for 2023 using SMOKE.
- Non-point emissions from the 2016v2 EMP for 2023 were processed with SMOKE. The non-point source category includes the same sources as those for the 2016 Base Case and was projected using various trends and procedures by EPA (2022b).
- The Clark County DOA provided 2023 projected emissions for commercial aviation and NAFB provided 2022 emissions, which were projected to 2023 by DES/DAQ. Both commercial and Federal aviation emissions from aircraft operations were processed with SMOKE.
- For other anthropogenic source categories, SMOKE was used to process the 2023fj emissions for the CC4c2 domain.

6.3 Quality Assurance

Quality assurance (QA) of emissions datasets is a critical step in performing air quality modeling studies. Because emissions processing is time consuming and involves complex manipulation of many different types of large databases, rigorous QA measures are a necessity to prevent errors in emissions processing from propagating to the PGM application. Ramboll performed a multistep emissions QA approach as developed for the WRAP 2002 modeling (Adelman, 2004) and following the procedures in EPA's modeling guidance (EPA, 2018a, pp. 60) and Section 2.20 of the SMOKE User's Manual (UNC, 2020, pp. 92). The following specific steps were performed to assure data quality:

1. The EPA 2016v2 platform data were reviewed and summarized to compare against any corresponding local inventory data compiled by Clark County for representativeness.
2. SMOKE is designed with flexible QA capabilities to generate standard and custom reports for checking the emissions modeling process. It includes reporting features to keep track of the adjustments at each processing stage and ensure that data integrity is not compromised. SMOKE-generates diagnostic files and summary reports were carefully reviewed for error and warning messages.
3. Visual displays were generated that include: (1) spatial plots of the emissions for each ozone precursor species (e.g., NOx, VOC, and CO); (2) summary tables of emissions for ozone precursors by major source category. This QA information was examined against the original point and area source data and summarized in an overall QA assessment.
4. Each set of biogenic emissions were carefully reviewed to ensure reasonable results consistent with input data, other modeling projects in the western US, and Ramboll's direct experience.

6.4 Summary of Emissions Results

Tables 6-4 and 6-5 present the 2016 and 2023 July weekday daily average anthropogenic emissions across the entirety of Clark County in tons per day (TPD). We calculated the average ozone season day emissions by averaging the daily emissions over the weekdays (Monday through Friday) in July excluding July 4th holiday, which was modeled as if it was a Sunday. The results were compared against the EPA 2016v2 daily county-level emission reports[18] for QA checks, and they matched well for all sectors except on-road mobile and airports, which are based on local data developed in this study. Figure 6-1 compares daily average NOx and VOC emissions by major anthropogenic category. On-road and non-road mobile sectors were the dominant anthropogenic categories for NOx in 2016, followed by airports and industrial point source categories. There is a significant decline in on-road mobile NOx emissions between 2016 and 2023 (-59%), primarily due to fleet turnover. There are also reductions in NOx emissions between 2016 and 2023 for non-road mobile, locomotives, and industrial point sources. NOx emissions from airports and non-point area source categories increased slightly in 2023.

For VOCs, the non-point sector was the dominant anthropogenic category, followed by non-road and on-road mobile sources in 2016. On-road and non-road mobile VOC emissions decrease the most (-44% and -6%, respectively) between 2016 and 2023. VOC emissions increased slightly for the non-point category in 2023.

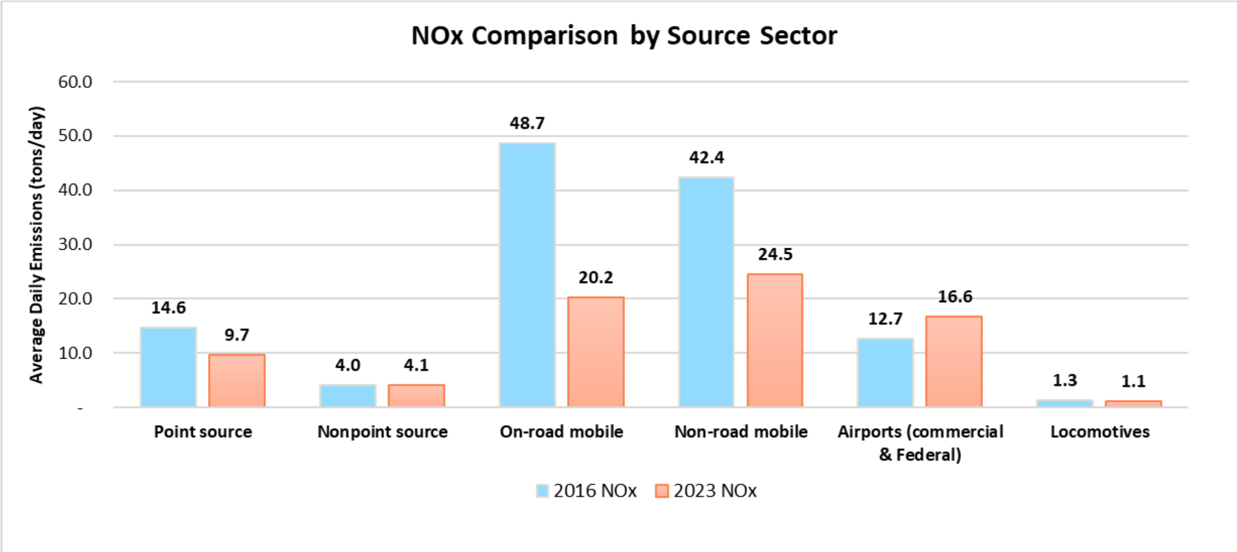
Table 6-4. July weekday average 2016 and 2023 anthropogenic NOx emissions (TPD) over the entirety of Clark County by major source sector.

Source Category	2016 NOx	2023 NOx
Point source	14.6	9.7
Nonpoint source	4.0	4.1
On-road mobile	48.7	20.2
Non-road mobile	42.4	24.5
Airports (commercial & Federal)	12.7	16.6
Locomotives	1.3	1.1
Fires	0.0	0.0
TOTAL	123.7	76.2

Table 6-5. July weekday average 2016 and 2023 anthropogenic VOC emissions (TPD) over the entirety of Clark County by major source sector.

Source Category	2016 VOC	2023 VOC
Point source	2.1	1.8
Nonpoint source	57.0	60.8
On-road mobile	27.8	17.7
Non-road mobile	29.5	27.6
Airports (commercial & Federal)	2.3	3.1
Locomotives	0.1	0.0
Fires	0.3	0.3
TOTAL	119.1	111.3

[18] Available at https://gaftp.epa.gov/Air/emismod/2016/v2/reports/county_daily/



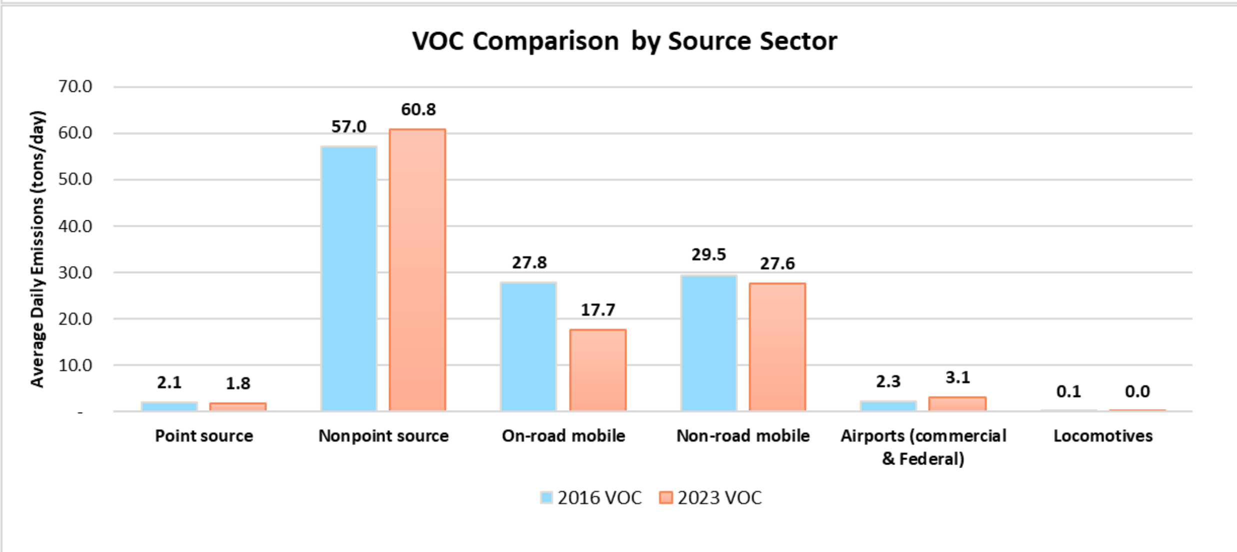


Figure 6-1. Comparison of July weekday average anthropogenic NOx (top) and VOC (bottom) emissions (TPD) between 2016 and 2023 over the entirety of Clark County by major source sector.

Figures 6-2 through 6-6 show the spatial distribution of 2016 NOx and VOC emissions and their differences in 2023. Figure 6-2 displays emissions for the on-road mobile category. The emissions are seen along major roadways, which confirms correct spatial allocation and decline in the future year. Figure 6-3 shows emissions for the non-road category, with most occurring over the populated urban area and a decline in 2023. Figure 6-4 displays emissions for the non-point category with hotspots over the Las Vegas Valley and emission increases for 2023. Figures 6-5 and 6-6 show emissions for airport and locomotive sectors, respectively.

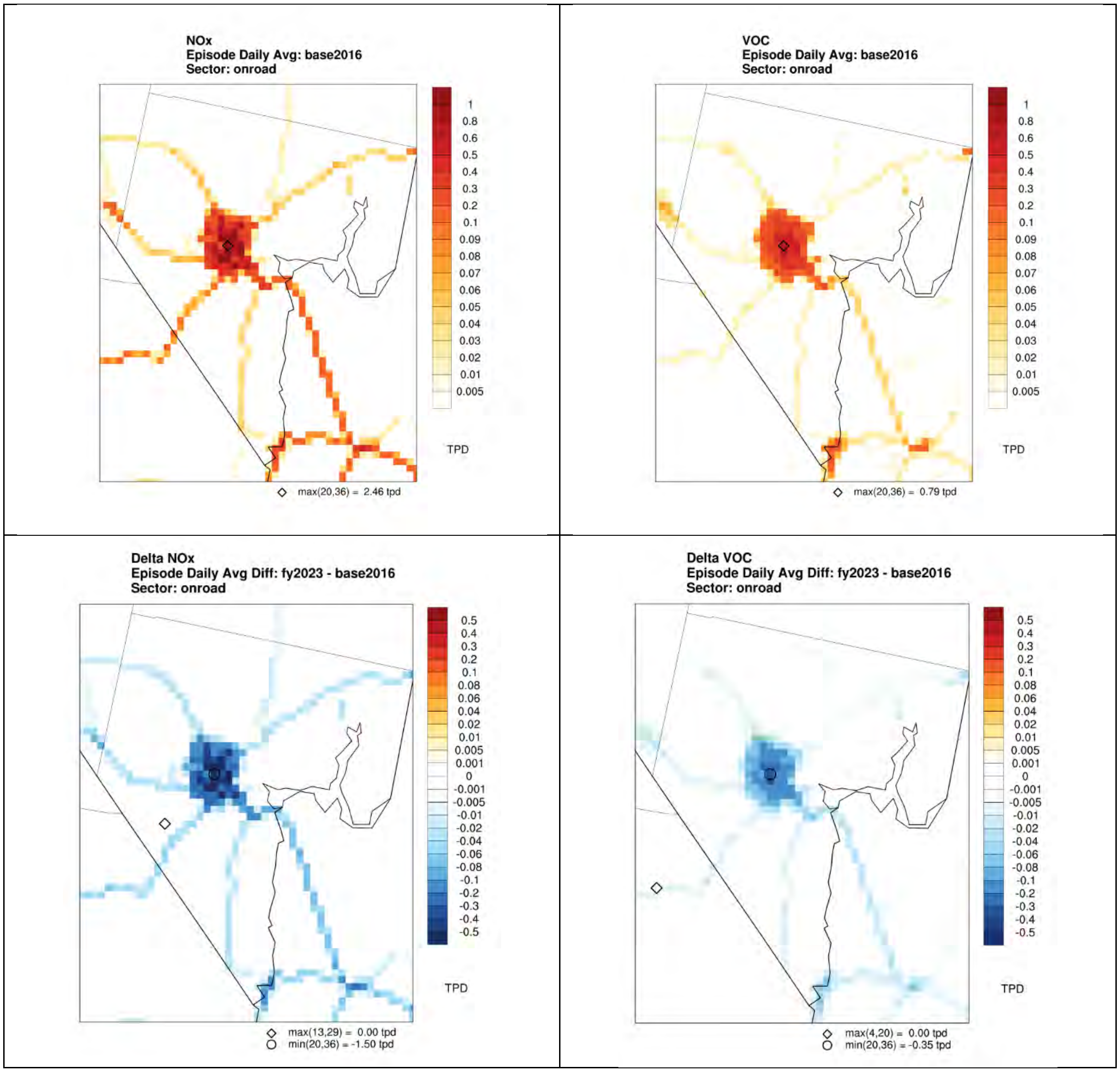


Figure 6-2. Spatial map of daily average NOx (left) and VOC (right) emissions for the on-road mobile category over the CC4c2 grid; 2016 (top) and differences between 2023 and 2016 (2023-2016, bottom).

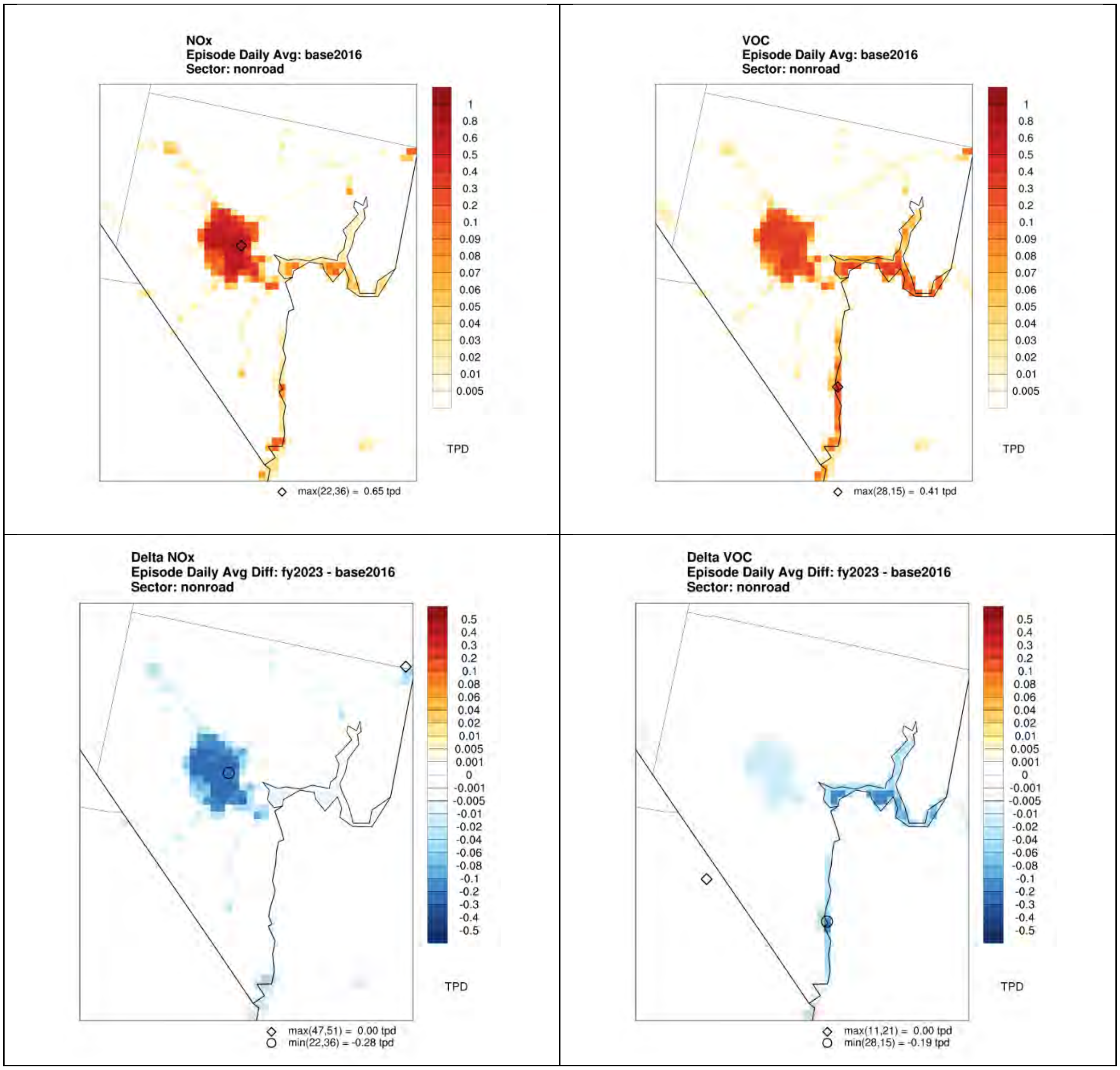


Figure 6-3. Spatial map of daily average NOx (left) and VOC (right) emissions for the non-road category over the CC4c2 grid; 2016 (top) and differences between 2023 and 2016 (2023-2016, bottom).

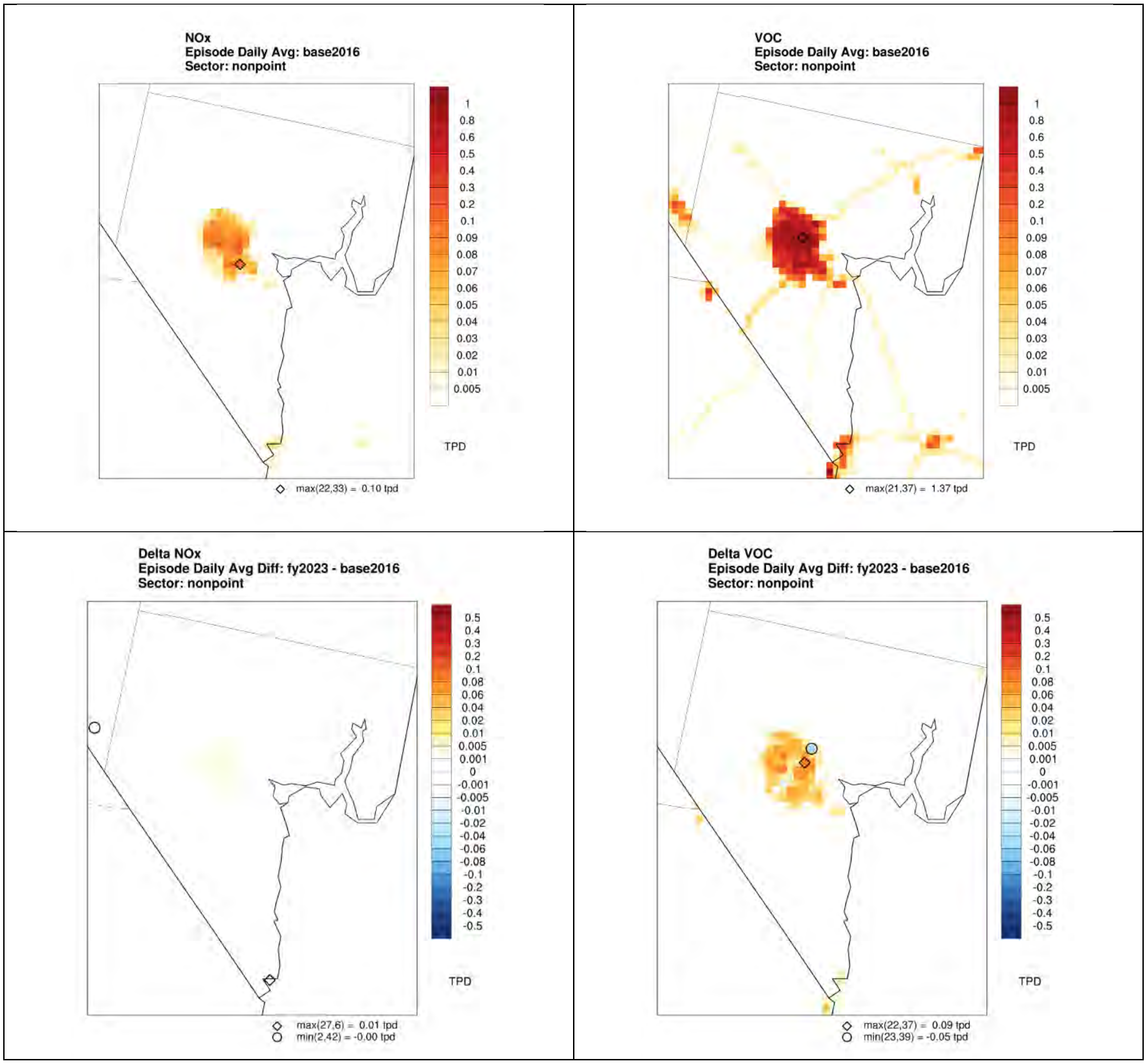


Figure 6-4. Spatial map of daily average NOx (left) and VOC (right) emissions for the non-point category over the CC4c2 grid; 2016 (top) and differences between 2023 and 2016 (2023-2016, bottom).

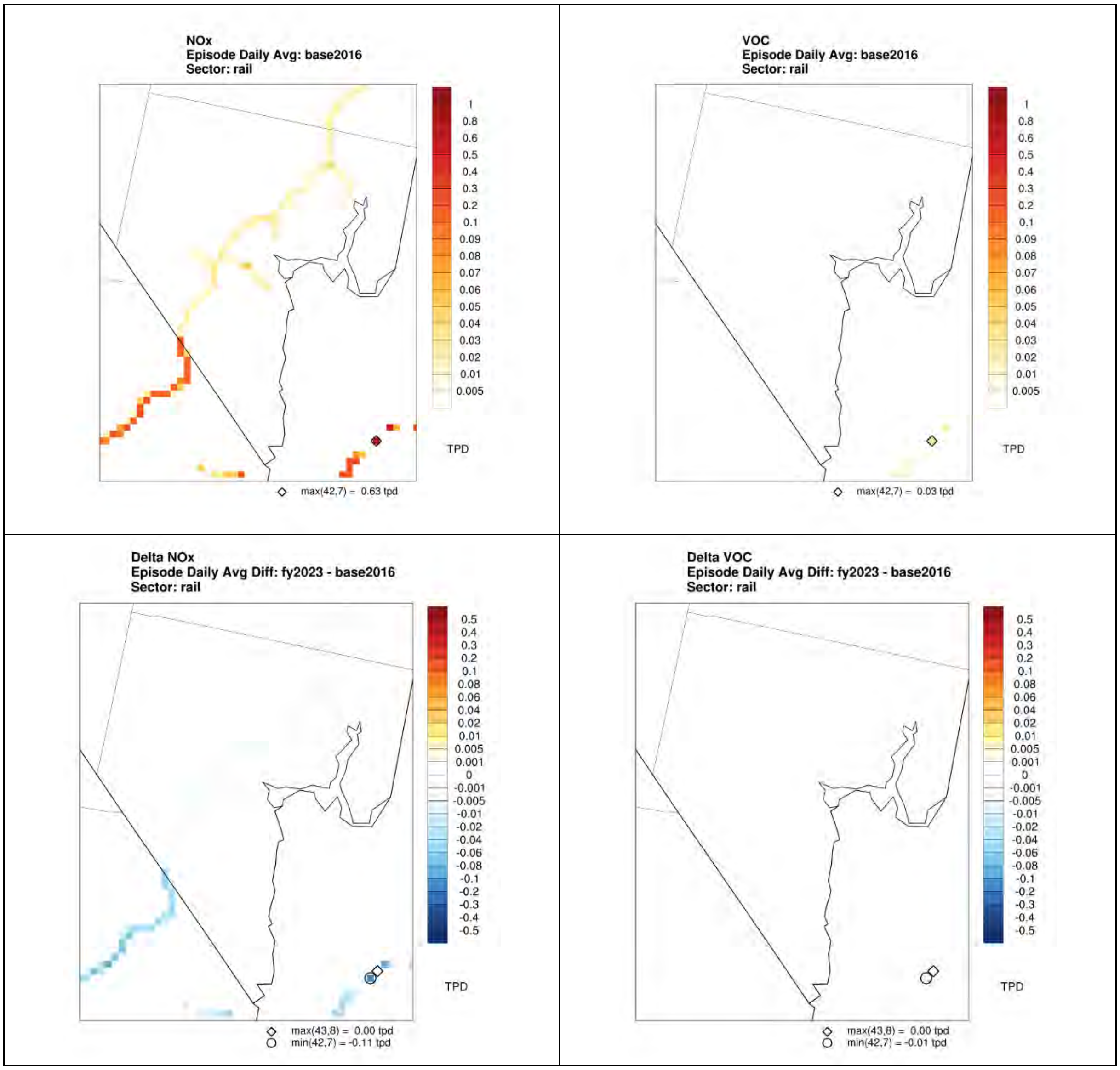


Figure 6-5. Spatial map of daily average NOx (left) and VOC (right) emissions for locomotives over the CC4c2 grid; 2016 (top) and differences between 2023 and 2016 (2023-2016, bottom).

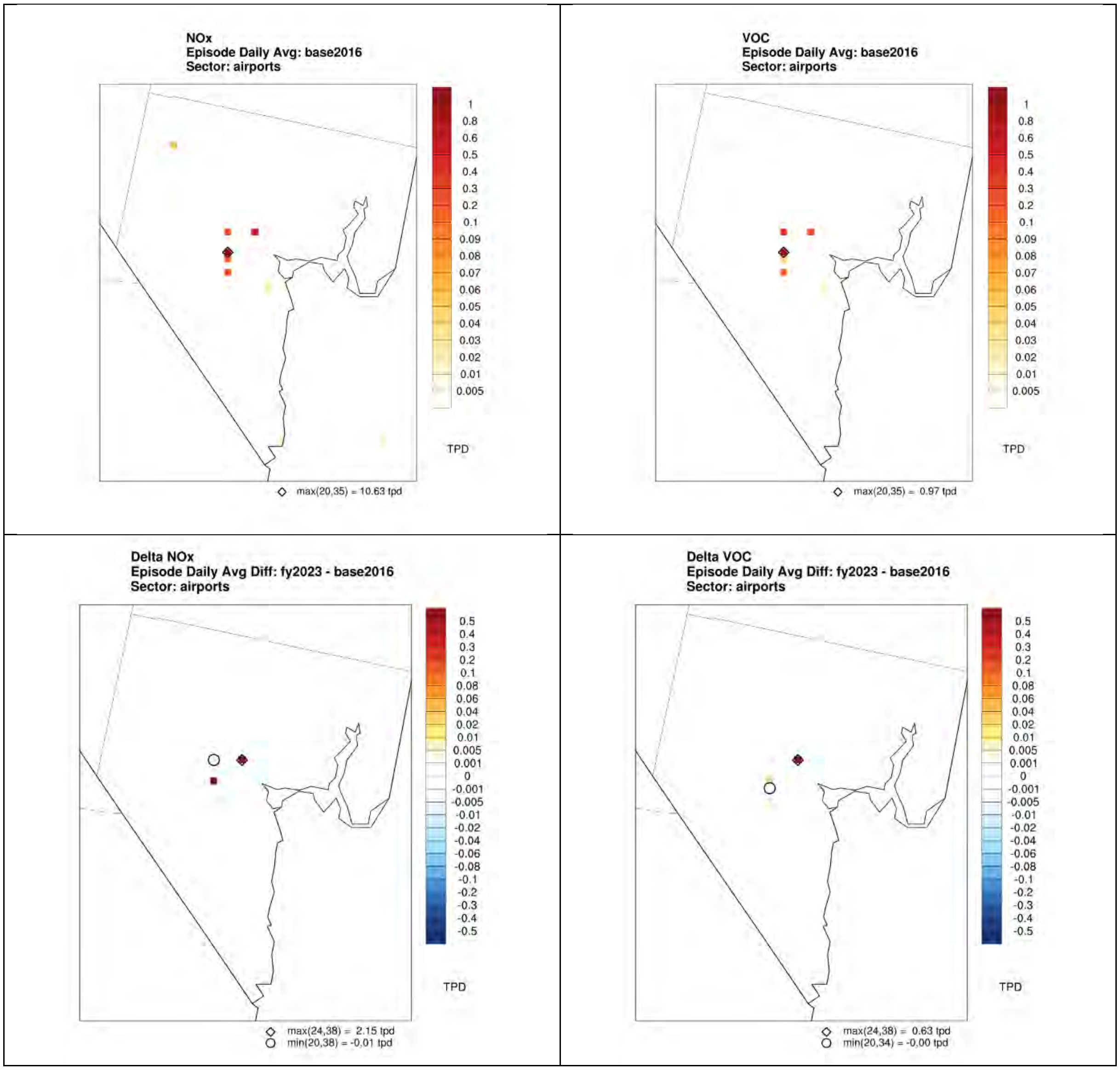


Figure 6-6. Spatial map of daily average NOx (left) and VOC (right) emissions for airports in the CC4c2 domain; 2016 (top) and differences between 2023 and 2016 (2023-2016, bottom).

7.0 OTHER MODEL INPUTS

7.1 CAMx-Ready Meteorological Inputs

As part of the development of the 2016v2 modeling platform, EPA generated CAMx-ready meteorological inputs for the 36US3 and 12US2 grids using WRF v3.8 and WRFCAMx v4.7. Ramboll has reviewed and used these meteorological inputs for several other projects. For this project, we used the most recent version of WRFCAMx (v5.2) to map the 4 km meteorological output data from the large WRF domain (Figure 5-1) onto the CC4c2 domain (Figure 4-2).

WRFCAMx is a program that translates WRF meteorological output fields into the input format required by CAMx. Additionally, WRFCAMx calculates turbulent vertical exchange coefficients (Kv) that define the rate and depth of vertical mixing in CAMx. Finally, WRFCAMx also maps specific fractional land use/landcover (LU/LC) categories from WRF to the categories defined within CAMx. WRFCAMx processing steps include:

- Reading the meteorological model output files and translating from the Coordinated Universal Time (UTC) to local time zones (if specified).
- Extracting (and interpolating as needed) meteorological data to the CAMx modeling domain.
- Aggregating or "collapsing" meteorological data from the WRF vertical layer structure to a coarser CAMx vertical grid (if specified).
- Computing Kv fields, mapping LU/LC, and diagnosing other variables specifically needed by CAMx or its pre-processors.
- Generating the CAMx-ready meteorological fields.

In addition to various updates, a novel aspect of WRFCAMx v5.2 is the ability to produce CAMx-ready meteorology in netCDF format, which is more versatile to manipulate and view than the original Fortran binary format generated with version v4.7. CAMx is able to read a mix of binary and netCDF input files. Table 7-1 summarizes the WRFCAMx option settings used for the CC4c2 domain in this study.

Table 7-1. WRFCAMx settings for Clark County CC4c2 domain.

WRFCAMx Option	Settings
CAMx nested grid	True: automatically adds nested grid buffer cells
Diagnostic fields	True: to support QA/QC and certain emission programs
Sea ice adjustment	False: no sea ice in the domain
KV Method	All: up to 3 methods are allowed depending on the WRF configuration (MYJ, YSU, CMAQ)
Sub-grid Convection	None: diagnoses sub-grid convective cloud cover (usually for grid resolution > 10 km)
Sub-grid stratiform	False: diagnoses sub-grid stratiform cloud cover (usually for grid resolution > 10 km)
Time zone	UTC
Layer mapping	Use all WRF layers, no collapsing

WRFCAMx diagnoses the vertical eddy diffusivity (Kv) values from WRF wind, temperature, and boundary layer parameters when turbulent kinetic energy (TKE) is not available in the WRF output (as is the case in all EPA WRF runs). Often the boundary layer treatments in WRF do not resolve urban landscapes sufficiently or correctly to maintain elevated mixing during the night, therefore another program is used to address this limitation. The program KVPATCH is a CAMx pre-processor that applies spatially varying minimum Kv profiles near the surface to account for the effects of the urban heat island that can result in enhanced vertical mixing near the surface. KVPATCH first sets a minimum Kv value in the surface layer (layer 1) between 0.1 to 1.0 m^2/s depending on the fraction urban land use present in a grid cell. Then a second treatment diagnoses a minimum vertical Kv profile above that through a user-specified depth, usually 100 to 200 m.

For the 12US2 domain, EPA selected the “YSU” Kv scheme for the 2016v2 CAMx modeling platform with a minimum Kv of 0.1 m^2/s. They applied KVPATCH to reset a minimum Kv profile for urban grid cells within the lowest 200 m of the surface. To be consistent, Ramboll also selected the YSU mixing scheme, however we set the depth of the Kv adjustment to 100 m to reflect stronger nightly inversions in cold, dry air reflective of western US desert environments. Also, as part of our quality assurance and quality control (QA/QC) steps, we found that WRF designates highways as “urban” land use. Since the grid cell areas covered by highways are very small (much less than 1%), KVPATCH was modified to apply the patch only to regions where urban land use is greater than 10% of grid cell area.

KVPATCH also includes an option that enhances Kv profiles through the depth of convective clouds. The purpose of this is to increase afternoon vertical mixing when and where convective clouds occur within the grid. WRF often collapses boundary layer depths during the afternoon under such convection due to surface cooling, when in fact such clouds enhance vertical turbulent exchange. A clear example of this is described below. We configured KVPATCH to bypass this convective mixing patch.

7.2 CMAQ-Ready Meteorological Inputs

WRF output was also processed using MCIP v5.2.1 to generate CMAQ-ready inputs for the CC4c2 domain. These inputs are necessary to develop weather-sensitive on-road and biogenic emissions using SMOKE-MOVES, BEIS and/or MEGAN, respectively. We also conducted QA reviews on the resulting MCIP dataset.

7.3 Quality Assurance

7.3.1 WRFCAMx

We performed a qualitative analysis of the WRFCAMx data from the EPA WRF application (referred to as “run0” in Section 5) for selected days to ensure the results were reasonable and consistent with WRF data. Selected fields such as the surface temperature, 10-meter winds, precipitation, YSU planetary boundary layer (PBL) depth, and total cloud optical depth generated from WRFCAMx were plotted for selected days (July 1 and 2, 2016), a period noted for poor meteorological replication in the LVV. This analysis should not be construed as a meteorological model performance, as there are no comparisons to observed conditions, but rather it served a visual check for obvious numerical or translation problems between WRF and CAMx.

On June 30 simulated precipitation occurred over Lake Mead and Arizona, southeast of Las Vegas, at around 4 PM Pacific Standard Time (PST), which moved south to southeast before leaving the CC4c2 domain at around 10 PM. Figure 7-1 shows the start of this precipitation episode with the wind vector field overlaid. Wind vectors show that surface wind divergence can be attributed in part to the down drafts associated with the precipitation event (Figure 7-1), as well as convergence/divergence patterns associated with terrain-induced flow. Horizontal wind speeds in the LVV affected by downdrafts exceeded 15 m/s. However, during the hours when high ozone concentrations are expected (11 AM to 3 PM), some stagnation occurred in the region.

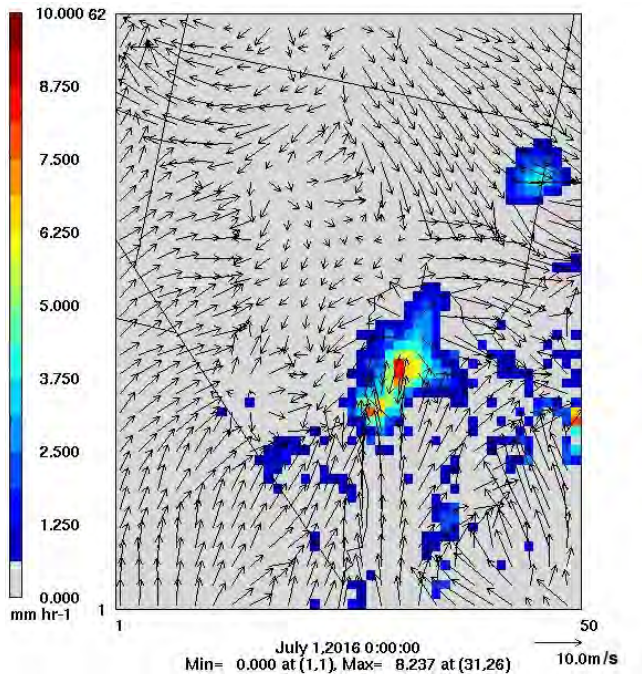


Figure 7-1. Surface precipitation and wind vectors in the CC4c2 domain on July 1, 2016, at 00 UTC (June 30, 2016, at 4 PM PST). Precipitation is shown in units of mm/hr, and wind vectors are in m/s.

A second simulated convective event started at 10-11 AM PST on July 1 near southwest Las Vegas (not shown). This convective area also moved in a southeast direction and left the domain at about 4 PM. On July 2, from 10 AM to 5 PM LST, southerly winds reestablished with the potential to transport air masses from beyond the southern portion of the domain into the LVV. In summary, the wind patterns responding to the precipitation cells are consistent with expectations, and no obvious errors or flaws stemming from WRFCAMx were identified.

In general, the simulated PBL exhibited low values (less than 200 m) at night. During 11 AM to 1 PM, the PBL increased to an excess of 2000 meters. However, on July 1 and July 2, the PBL collapsed dramatically in the middle of the day in apparent response to the development of a convective cell that caused thermal cooling of the surface (Figure 7-2). As suggested earlier in explaining KVPATCH, this suggests a high degree of complexity in the PBL dynamics, and it may be worth examining it as part of CAMx evaluations during ozone events. WRF commonly develop such features during convective events, and no problems associated with WRFCAMx were apparent.

Simulated temperature ranged between 12°C to 48°C (54°F to 118°F) during July 1 and 2, with lower values at night and higher temperatures during the day. On July 1, the maximum temperatures in the LVV occurred around 11 AM PST. Lower temperatures occurred in the higher elevations of the Sheep and Spring Mountains to the west and northwest of the LVV, respectively. WRF appeared to accurately capture the urban heat island effect. On July 1 at midnight, the highest temperatures were simulated in Las Vegas, and this persisted through the overnight hours. Some grid cells along the eastern border of Clark County with Arizona showed constant temperatures around 70° F. These cells are co-located with the Colorado River and Lake Mead, which act as a heat reservoir, explaining the constant temperature. Around Lake Mead temperature gradients can be observed on July 2 at 21 UTC (1 PM PST) when temperatures surrounding the lake were around 118°F and cells within the lake remained around 70°F (Figure 7-3). No problems associated with WRFCAMx were apparent.

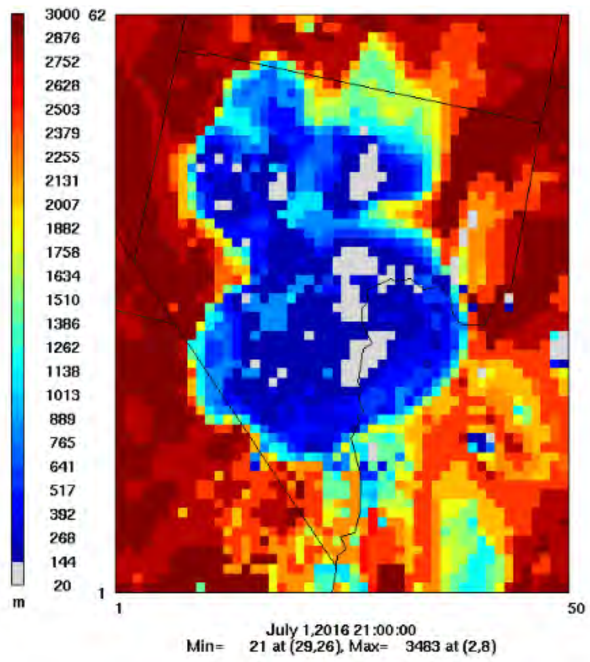


Figure 7-2. Planetary boundary layer (PBL) depth in the CC4c2 domain on July 1, 2016, at 21 UTC (July 1, 2016, at 1 PM PST). PBL is shown in meters (m) above ground.

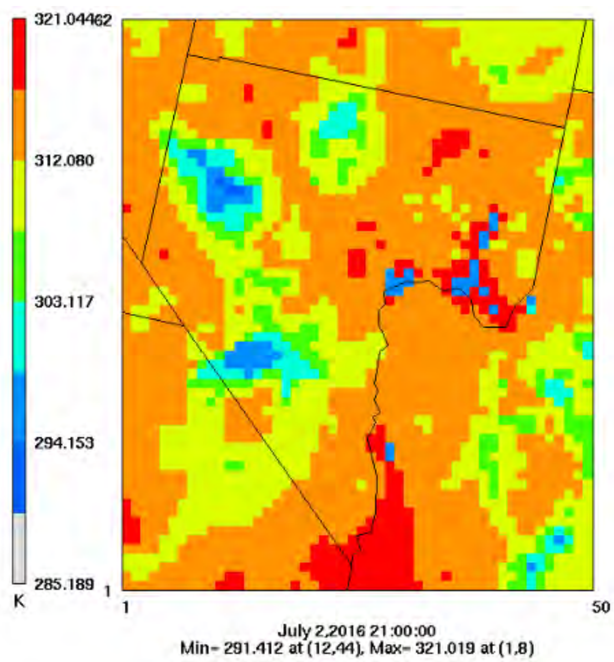


Figure 7-3. Temperature in the CC4c2 domain on July 2, 2016, at 21 UTC (July 2, 2016, at 1 PM PST). Temperature is shown in Kelvin (K).

During July 1 and 2 simulated cloud cover was generally sparse, however large cloud optical depth values were correlated to convective precipitation cells. During the hours of high ozone formation (11 AM to 3 PM) on July 2, spotty cloud cover conditions were simulated over the domain (Figure 7-4). No problems associated with WRFCAMx were apparent. It is highly likely that invoking the sub-grid convective diagnosis in WRFCAMx would have increased the amount of cloudiness during the daytime hours.

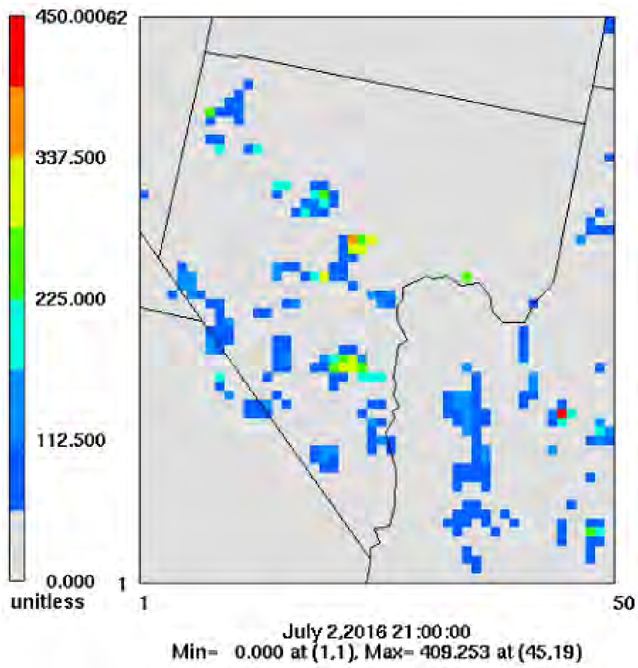


Figure 7-4. Cloud optical depth in the CC4c2 domain on July 2, 2016, at 21 UTC (July 2, 2016, at 1 PM PST).

In addition to CAMx-ready meteorological inputs, WRFCAMx processed the WRF LU/LC dataset to CAMx LU/LC inputs fields with proper mapping to CAMx categories. We conducted QA/QC on the resulting CAMx-ready landcover files to ensure reasonable characterization throughout the CC4c2 domain. LU/LC extractions from WRF were plotted and compared to the topography in Clark County. The largest two elevations in Clark County correspond to the Spring Mountains and Sheep Range. Mountains, urban areas, and vegetative type were consistent with known topography and landcover in the region (Table 7-2). The urban landcover clearly shows Las Vegas and highways. Deciduous shrubs cover most of Clark County and the rest of the CC4c2 domain. Evergreen needleleaf forests cover the mountain ranges in the region (Figures 7-5 through 7-7). No problems associated with WRFCAMx were apparent.

Table 7-2. CAMx LU/LC coverages over the CC4c2 domain.

LU/LC Variables	Description	Coverage
urban	Urban	Shows Las Vegas
dshrub	Deciduous shrub	Covers most of the 4km domain
eneedl	Evergreen needleleaf forest	Covers the Sheep Range and Spring Mountains
water	Water	Follows the Colorado River and Lake Mead
mwood	Mixed woodland	Small to negligible
desert	Desert (barren)	Small to negligible
swamp	Swamp	Small to negligible
cropland	Cropland	Small to negligible
lgrass	Long grass	Small to negligible
tforest	Transitional forest	No values
tundra	Tundra	No values
icrops	Irrigated cropland	No values
cotton	Cotton	No values
maize	Maize	No values
sugar	Sugar	No values
rice	Rice	No values
sgrass	Short grass	No values
tshrub	Thorn shrub	No values
eshrub	Evergreen shrub	No values
ddecid	Drought deciduous trees	No values
tbroad	Tropical broadleaf forest	No values
dbroad	Deciduous broadleaf forest	No values
dneedl	Deciduous needleleaf forest	No values
ebroad	Evergreen broadleaf forest	No values
Lake	Lake	No values
Ice	Ice	No values

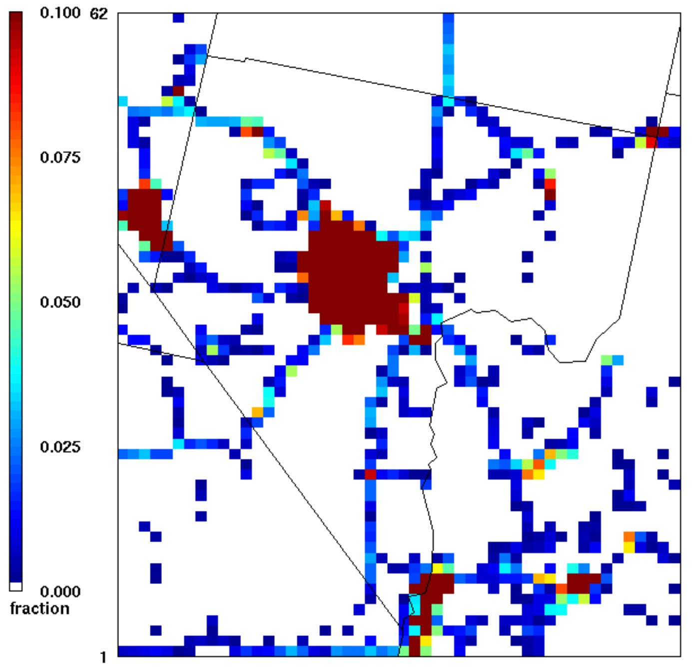


Figure 7-5. Land use categorized as “urban” in the CC4c2 domain.

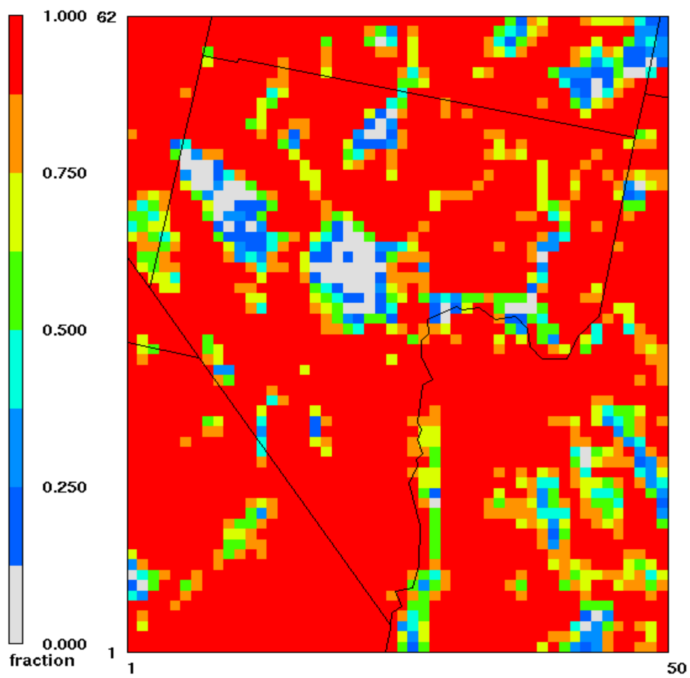


Figure 7-6. Land use categorized as “deciduous shrub” in the CC4c2 domain.

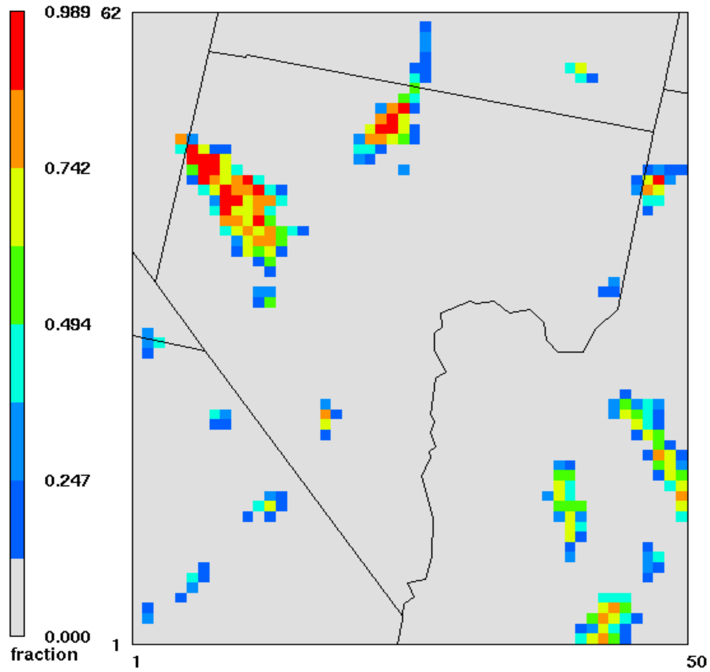


Figure 7-7. Land use categorized as "evergreen needleleaf forest" in the CC4c2 domain.

7.3.2 KVPATCH

Vertical diffusivity (Kv) fields modified with KVPATCH were compared to the original Kv fields from WRFCAMx. Figure 7-8 shows an example of nighttime Kv differences arising from the use of KVPATCH and illustrates that the adjustment was correctly applied to the urban areas around Las Vegas and Fort Mojave Reservation just east of Clark County. Note that only some areas needed an upward adjustment to reflect the minimum Kv profile.

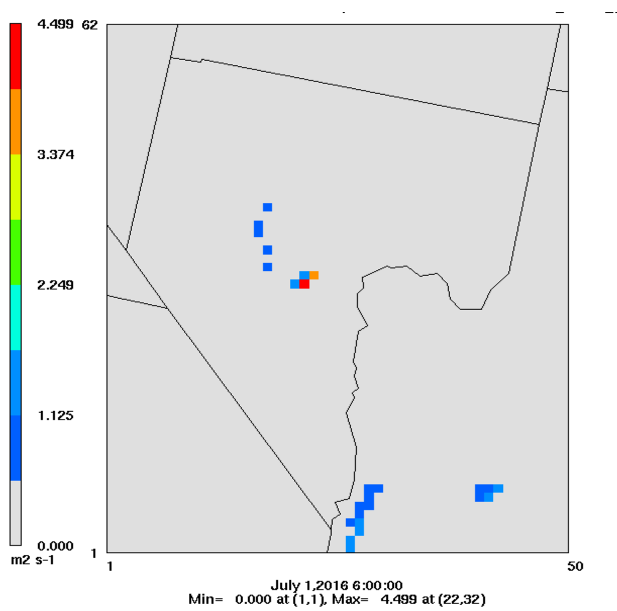


Figure 7-8. Enhancements generated from applying KVPATCH in layer 3 on July 1, 2016, at 6 UTC (June 30, 2016, 10 PM PST)

7.3.3 MCIP

We found that MCIP results were reasonable and similar to WRFCAMx. MCIP results were quality assured by comparing a few meteorological fields such as surface winds and temperature against the corresponding WRFCAMx extraction for selected days. Figure 7-9 shows a comparison between WRFCAMx and MCIP surface temperature on June 30 at 4 PM PST and it illustrates that the spatial variation in both is very similar if not identical, which is expected. Notice that the WRFCAMx domain is larger than the MCIP domain by extra rows and columns around the perimeter because CAMx requires meteorological inputs to include nested grid buffer cells.

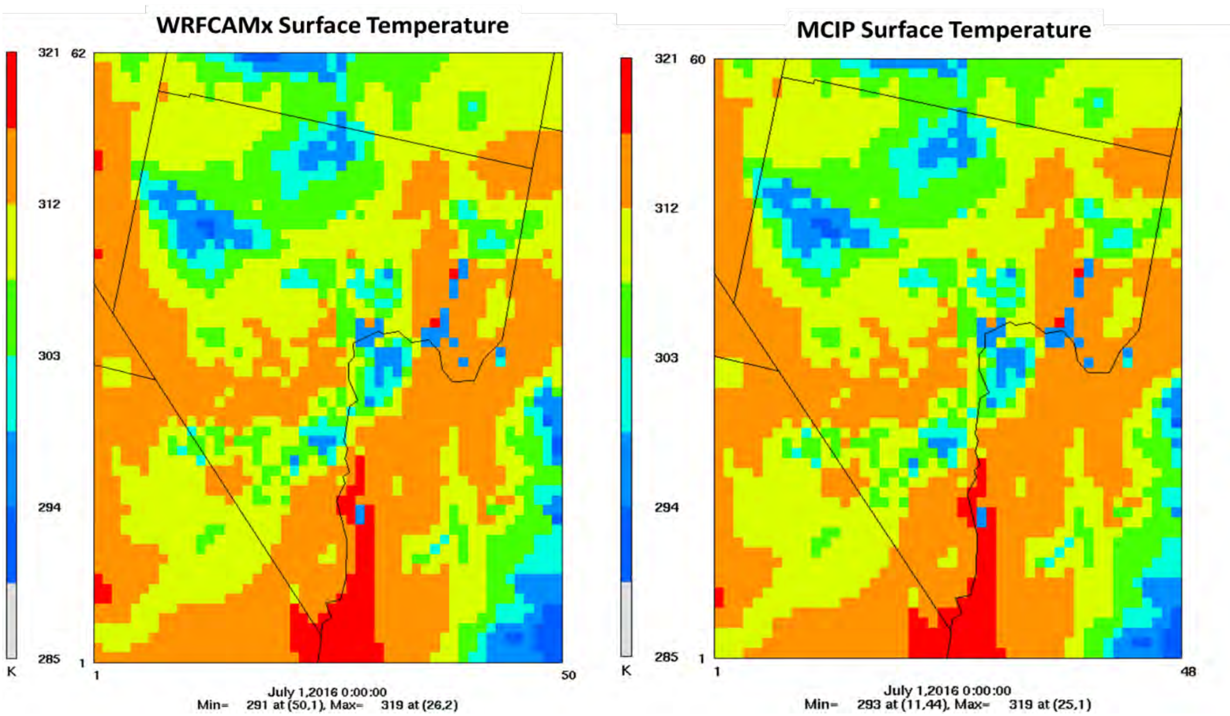


Figure 7-9. WRFCAMx and MCIP surface temperatures for July 1, 2016, at 0 UTC (June 30, 2016, 4 PM PST).

7.4 Initial and Boundary Conditions

Initial and boundary conditions (IC/BC) for the 36US3 and 12US2 domains were obtained from the EPA 2016v2 modeling platform (EPA, 2022a,c). The 36US3 IC/BCs were developed by EPA from version 3.1.1 of the hemispheric version of the Community Multi-scale Air Quality Model (H-CMAQ). The resulting BCs were generated at one-hour intervals. Three-dimensional concentration output fields from EPA's 2016_fj and 2023_fj 36US3 CAMx simulation were then used to generate BCs for the 2016_fj and 2023_fj 12US2 base case scenarios, respectively. Ramboll has reviewed and used these IC/BC inputs for several other projects. Note that alternative sources of BC were tested in CAMx as described in Section 8.4.

7.5 Ozone Column and Photolysis Rates

Total atmospheric ozone column data are needed to derive clear-sky photolysis rate inputs for CAMx. Typically, 24-hour ozone column data retrieved from the Ozone Monitoring Instrument (OMI) aboard the Aura satellite are available on FTP sites supported by the National Aeronautics and Space Administration (NASA, 2022) and used for this purpose. In this project, however, ozone column and photolysis rate values for the 36US3 and 12US2 domains were obtained from the 2016v2 EPA Modeling platform. Ramboll has reviewed and used these chemical data inputs for several other projects. In 2-way nested grid applications, CAMx interpolates master grid ozone column inputs to all nested grids; i.e., the ozone column dataset prepared by EPA for the 12US2 grid was used for the entire 12US2/CC4c2 grid system. EPA developed photolysis rates for the Carbon Bond version 6, release 4 (CB6r4) photochemical mechanism. For this project, we applied CAMx v7.20 using the latest Carbon Bond mechanism (CB6r5), which is fully compatible with photolysis rates developed for CB6r4.

8.0 BASE YEAR AND SENSITIVITY MODELING

This Section describes the CAMx 2016 base year modeling configuration, initial and sensitivity applications, and model performance evaluation. Seven CAMx runs were conducted:

1. An initial base case running only gas-phase ozone chemistry;
2. Inclusion of aerosol chemistry and an improvement in the spatial characterization of emissions from Harry Reid International Airport;
3. Alternative North American boundary conditions using output from the GEOS-Chem global chemistry model;
4. A series of short tests with modified vertical diffusion coefficients;
5. Replacement of biogenic emissions from BEIS3.7/BELD5 with emissions from BEIS3.6/BELD4;
6. Replacement of biogenic emissions from BEIS3.7/BELD5 with emissions from BEIS4/BELD6;
7. Alternative North American boundary conditions using output from the CAM-Chem global chemistry model.

8.1 CAMx 2016 Modeling Platform

Clark County's photochemical modeling is based on the EPA's 2016v2 MP, which includes CAMx-ready emissions, meteorology, initial/boundary conditions (IC/BC), and other model input datasets. The historical base year is 2016 and the future base planning year is 2023. EPA input datasets are available for two nested grids: 36US3 covering North America and 12US2 covering the conterminous US. A third CC4c2 grid has been added covering the CCNAA, the entirety of Clark County, and portions of surrounding areas in southern Nevada and southeastern California (see Figures 4-1 and 4-2). All grids run with the full 35 layer vertical grid structure (see Table 4-3).

Model simulations were conducted using CAMx v7.2, which was publicly released in May 2022 (Ramboll, 2022b), and employed the Carbon Bond version 6 (CB6) photochemical mechanism to be consistent with the EPA 2016v2 databases. The Clark County modeling period spans from May 1 through August 31, 2016. A one-month spin up period in April is run without the 4 km grid to initialize the model from ICs.

Table 8-1 lists the initial 2016 base case model configuration. This configuration is identical to the EPA 2016v2 MP except for the following:

- The CC4c2 grid is added with associated meteorological and emission inputs.
- The modeling period is May 1 through August 31 (with April spin-up) instead of a full calendar year.
- CB6 gas-phase ozone chemistry is run exclusively without aerosols to shorten CAMx runtimes.
- Vertical advection is solved using the "Piecewise Parabolic Method" (PPM), a new and less numerically diffusive option in CAMx v7.2, instead of the original implicit hybrid method in earlier CAMx versions used by EPA.

Table 8-1. CAMx model configuration for the CCNAA 2016 initial base case simulation.

Model Component	CCNAA Application	Comment
Model Code	CAMx v7.20 - May 2022	
Horizontal Grids		
Map Projection	Lambert Conic Conformal	EPA 2016 MP
36 km (36US3)	172 x 148 cells	EPA 2016 MP (1-way nesting)
12 km (12US2)	396 x 246 cells (no buffer cells)	EPA 2016 MP (2-way nesting)
4 km (CC4c2)	50 x 62 cells (with buffer cells)	CCNAA grid (2-way nesting)
Vertical Grid	35 layers	EPA 2016 MP, defined by WRF
Initial Conditions	30-day spin-up on 12US2 grid from "clean" ICs using 2016 emissions	Start 12US2/CC4c2 2-way nests on May 1
Boundary Conditions	EPA 2016 MP 12US2 BCs	
Time Zone	UTC	EPA 2016 MP
Emissions		
36/12 km Data Sources	EPA 2016v2 MP	
4 km Data Sources	EPA 2016v2 MP + Clark County Data	
Models/Processing Tools	SMOKE, MOVES3, SMOKE-MOVES, BEIS3.7/BELD5	CCNAA grid
Plume-in-Grid	Off	No large point sources in high-resolution CCNAA grid
In-line Ix emissions	On	Oceanic halogens
Chemistry		
Gas Phase Chemistry	CB6r5	Latest mechanism available
Aerosol Chemistry	None	Gas phase only
Meteorological Interface	WRFCAMx v5.2	
Horizontal Diffusion	Smagorinsky	Spatially variant K-theory
Vertical Diffusion	YSU Kv formulation	Minimum Kv 0.1 to 1.0 m^2/s
ACM2	Off	Boundary layer convection
Sub-grid Cloud Convection	Off	
Deposition		
Dry Deposition	Zhang03	
Wet Deposition	On	rain/snow/graupel
Surface Chemistry Model	Off	
Bi-directional Ammonia	Off	For aerosol chemistry
Numeric Solvers		
Gas Phase Solver	Euler Backward Iterative(EBI)	Default fast and accurate solver
Vertical Advection	Piecewise Parabolic Method (PPM)	Default
Horizontal Advection	Piecewise Parabolic Method (PPM)	Default
Integration Time Step	Wind speed dependent	~0.5-1 min (4 km), 1-5 min (12 km), 5-15 min (36 km)
Super Stepping	On	Maximizes time step selection

8.2 Evaluation Approach

The CAMx performance evaluation followed procedures recommended by EPA (2018a). An important purpose of the evaluation is to judge the reliability of the model in predicting ozone and related compounds and to establish a level of confidence that modeled ozone responses to changes in emissions within the CCNAA are sufficiently accurate and reliable. The CAMx 2016 results were compared against observed ambient ozone and precursor concentrations, as available, to establish the extent to which the model is capable of reproducing conditions that actually occurred. The model performance evaluation included many types of graphical and statistical comparisons between predicted and observed concentrations, as documented in the Modeling Protocol (Ramboll, 2022a). Following the evaluation, diagnostic tests were undertaken to investigate model sensitivity to key inputs, such as emissions, meteorology, chemistry, and boundary conditions, and to improve model performance in replicated observed conditions.

Statistical metrics involved comparing simulated surface ozone and NO_2 concentrations paired in space and time with measurements archived in EPA's Air Quality System (AQS) database[19]. Figure 8-1 shows the location of AQS sites operating within central Clark County during the summer of 2016.

Figure 8-1. Map of air quality monitoring sites that operated within central Clark County during the summer of 2016. Ozone sites are noted in green, the high elevation site in the Spring Mountains is noted in yellow, and NOx monitoring sites are noted in blue (which are co-located with ozone sites at Jerome Mack and Joe Neal). Additional sites not contained within the image include: Jean to the southwest, Indian Springs to the Northwest, and Mesquite far to the northeast.

[19] http://www.epa.gov/air/data/.

The Atmospheric Model Evaluation Tool (AMET[20,21]; EPA, 2022f) is a suite of software designed to facilitate the analysis and evaluation of model predictions against observations. AMET matches model output from grid cells with observations from monitoring sites operating within one or more networks. AMET also maps individual modeled species to corresponding compounds reported in the observation database. Model and observation data pairings are then used to analyze the model's performance using a variety of statistical and graphical techniques. AMET v1.5 is the latest version, released in August 2022.

EPA has deemphasized the use of statistical goals because of a historical tendency to focus on achieving such goals in lieu of assessing whether a model properly simulates atmospheric processes. Models may often look correct but for the wrong reasons, a result of compensatory errors. However, model performance goals are still useful for interpreting model performance and putting the performance into context. Building off the work of Simon et al. (2012), Emery et al. (2016) developed a set of performance goals and criteria based on the variability in past US photochemical modeling exercises. "Goals" indicate statistical values that the top one-third of applications have met and should be viewed as the best a model can be expected to achieve. "Criteria" indicate statistical values that about two thirds of past applications have met and should be viewed as a performance level that models should be able to achieve. Statistical results outside the criteria indicate that the model performs poorly. We compared CAMx 2016 ozone performance statistics for normalized mean bias (NMB), normalized mean error (NME) and correlation coefficient (r) against the goals and criteria proposed by Emery et al. (2016), as listed in Table 8-2.

Table 8-2. Recommended benchmarks for ozone statistical performance (Emery et al., 2016). These goals apply in cases with and without the use of an observed minimum cutoff concentration (e.g., 60 ppb).

Statistic	Goal	Criteria
NMB	$< \pm 5\%$	$< \pm 15\%$
NME	$<15\%$	$<25\%$
R	>0.75	>0.50

8.3 Initial Base Case Model Performance Evaluation

The initial base case evaluation focused on statistical comparisons involving maximum daily 8-hour average (MDA8) ozone and hourly NOx in the CCNAA to assess overall predictive skill in reproducing day-to-day variability of observed air quality at key monitors and to identify any fatal flaws that required corrective action. The evaluation also included an ozone performance evaluation across the Mojave desert region to assess transport from California.

8.3.1 Summary of Results

Results from the evaluation of the initial 2016 base case simulation are summarized below:

- MDA8 ozone was under predicted for most months and most Clark County sites, but generally remained within statistical benchmark criteria.
  - Model bias transitioned from large under predictions in May to near zero bias by August;
  - Performance was reflective of the inputs provided by the EPA 12US2 2016v2 database, and not surprisingly EPA results showed similar performance;
  - Under prediction bias was relatively larger on high observed ozone days (>60 ppb);

[20] https://www.cmascenter.org/amet/.
[21] https://www.epa.gov/cmaq/atmospheric-model-evaluation-tool.

  - Regional upwind performance in southern California followed similar patterns, with generally larger under prediction bias than in Clark County.
- NO_2 concentrations in Las Vegas transitioned from over prediction to under prediction from May to August.
  - This was an opposite trend from ozone and presented an early indication that NOx reductions may lead to ozone increases (a so-called "NOx-disbenefit");
  - The predicted hourly diurnal NO_2 pattern was overestimated at all hours and "neighborhood" monitors that were not directly sited near freeways.
  - Predictions indicated either too much NOx emissions, improper temporal or spatial allocation, and/or insufficient vertical mixing especially during commute hours.
  - Animations of ozone spatial patterns indicated lower ozone in central Las Vegas and much higher ozone in outlying areas, further suggesting NOx-rich conditions in central Las Vegas that inhibited ozone formation and may lead to NOx-disbenefits.

8.3.2 MDA8 Ozone Bias and Error Performance Statistics

Table 8-3a lists monthly NMB and NME statistical performance for MDA8 ozone over all days and all ozone monitoring sites within the CC4c2 domain. The table compares results from the Clark County initial base case and EPA's 2016v2 12US2 simulation (EPA, 2022c). NMB and NME are color coded for visual reference to statistical goals and criteria benchmarks.

Performance results between the base case and EPA simulation were very similar, showing a consistent and systematic negative bias over all months. A rather large negative bias outside of the criteria benchmark occurred in May, followed by a transition to smaller bias through August well within the statistical goal. The large bias in May also led to higher gross error than other months in both models, while June through August exhibited consistent gross error of just above 10%, which is well within the statistical goal.

Table 8-3a. Monthly model performance statistics for MDA8 ozone over all days and all ozone monitoring sites within the CC4c2 domain that operated during the summer of 2016. Normalized mean bias (NMB) and normalized mean unsigned error (NME, also referred to as gross error) are shown with color coding indicating statistics outside performance criteria (red), between goals and criteria (yellow) and within goals (green). Results from the Clark County initial base case and EPA's 2016v2 12US2 simulation are compared.

Month	MDA8 Ozone (no cutoff)			
	NMB (%)		NME (%)	
	CC4c2	EPA 12US2	CC4c2	EPA 12US2
May	-17.9	-15.9	18.3	16.1
June	-9.2	-6.5	11.2	9.0
July	-8.2	-7.9	11.1	10.7
Aug	0.1	-0.6	10.7	11.5
May-Aug	-8.8	-7.7	12.8	11.8

Table 8-3b presents the same information but limited to sites and days when observed MDA8 ozone exceeded 60 ppb. Similar patterns are evident on high ozone days, but there was a tendency toward larger negative bias even though gross error remained in the low teens during June through August.

Table 8-3b. As in Table 8-3a, but for all sites and days when monitored MDA8 ozone exceeded 60 ppb.

Month	MDA8 Ozone (60 ppb cutoff)			
	NMB (%)		NME (%)	
	CC4c2	EPA 12US2	CC4c2	EPA 12US2
May	-21.5	-19.7	21.5	19.7
June	-11.3	-9.2	12.7	9.6
July	-11.7	-12.0	12.7	12.6
Aug	-4.3	-5.6	11.4	11.8
May-Aug	-11.5	-11.1	13.9	12.8

Table 8-4 breaks out monthly NMB and NME over all days (i.e., no 60 ppb cutoff) at each monitoring site within the CC4c2 domain. Similar color shading is used to visually characterize values relative to goal and criteria benchmarks. The under prediction patterns were consistent across all sites, so there was no single site that influenced the statistics in Table 8-3a. The consistently worst performing site was in California, upstream of Clark County, which monitors air that often arrives directly from the Los Angeles basin. The best performance throughout the modeling period was achieved at Mesquite, far to the northeast of Las Vegas. Within the LVV, Joe Neal and JD Smith were the worst performing sites during May through July.

Table 8-4. Monthly model performance statistics for MDA8 ozone over all days at each monitoring site within the CC4c2 domain that operated during the summer of 2016. Normalized mean bias (NME) and normalized mean unsigned error (NME) are shown with color coding indicating statistics outside performance criteria (red), between goals and criteria (yellow) and within goals (green).

		May		June		July		Aug	
Site_ID	Name	NMB	NME	NMB	NME	NMB	NME	NMB	NME
060711001	California	-24.7	24.7	-17.3	17.3	-17.0	17.9	-11.8	12.4
320030022	Apex	-18.7	18.8	-9.6	9.9	-8.6	11.5	1.5	9.8
320030023	Mesquite	-12.3	13.4	-2.7	7.1	0.4	6.7	12.9	22.9
320030043	Paul Meyer	-18.2	18.4	-10.3	12.0	-9.0	10.9	-2.4	9.5
320030071	Walter Johnson	-17.8	18.0	-8.9	11.4	-8.7	10.8	-0.5	9.4
320030073	Palo Verde	-15.0	16.0	-7.1	10.5	-7.3	10.5	0.3	9.9
320030075	Joe Neal	-20.0	20.1	-11.3	13.2	-11.1	12.1	0.6	9.1
320030298	Green Valley	-15.6	16.6	-10.0	11.4	-6.1	10.2	2.0	11.8
320030540	Jerome Mack-NCORE	-19.5	19.6	-9.6	11.7	-9.4	11.9	-1.1	10.0
320030601	Boulder City	-16.0	16.2	-7.2	8.0	-3.0	10.1	-3.8	10.9
320031019	Jean	-16.5	16.7	-7.9	9.3	-6.9	9.0	-1.6	8.9
320032002	J.D. Smith	-20.9	21.1	-13.4	14.5	-10.6	12.5	-0.7	9.6
320037771	SM Youth Camp	-19.7	19.7	-9.2	11.3	-9.2	10.1	1.6	9.7
320037772	Indian Springs	-15.9	16.6	-5.4	10.6	-4.6	10.0	3.8	10.2
320038000	LV Paiute	-17.3	17.5	-10.0	11.5	-9.3	10.4	4.3	9.7

These results indicated that the model performed poorly in May, marginally well during June, typically well during July, but notably well during August. The systematic under prediction tendency suggested a consistent source of error. Additional graphical and day-specific comparisons described below were analyzed to identify patterns that might uncover or direct further investigation into the source of error. Additionally, sensitivity tests were conducted to assess the influence from different model configuration options and inputs.

8.3.3 Graphical Analyses of Model Performance

Figure 8-2 displays a spatial map of site-specific monthly NMB patterns for MDA8 ozone across the CC4c2 domain. In this case, NMB was determined from all days without the 60 ppb cutoff applied, so the maps are consistent with the data in Table 8-4. These plots show the systematic negative bias in May and the progressive improvement through August. Again, the consistent bias among all LVV core sites is notable.

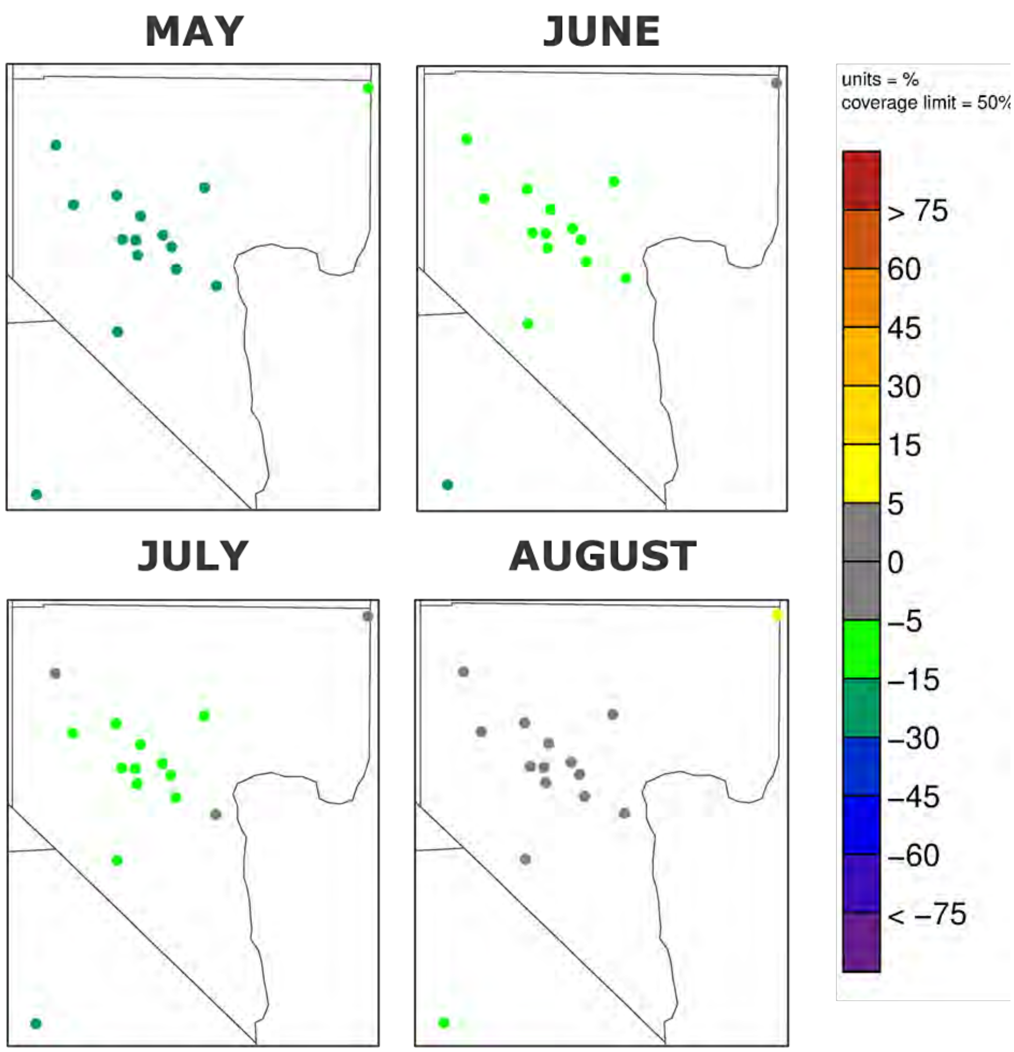


Figure 8-2. Map of site-specific monthly normalized mean bias (NMB) patterns for MDA8 ozone within the CC4c2 domain.

Figure 8-3 presents a similar spatial map of site-specific monthly NMB, but for selected monitoring sites across the Mojave Desert of Southern California. These sites monitor the air mass that is often transported between the Los Angeles basin and the LVV. Simulated MDA8 ozone for these statistics were taken from the 12US2 grid. The plots show the same general pattern of systematic negative bias and month-by-month improvement through August. While performance was fairly consistent among all desert sites, the under prediction bias was much larger than the LVV sites. This implicated a lack of regional ozone and associated transport as a likely contributor to poor performance in the LVV. Such performance issues were previously reported in EPA's 2016v2 model performance evaluation (EPA, 2022c).

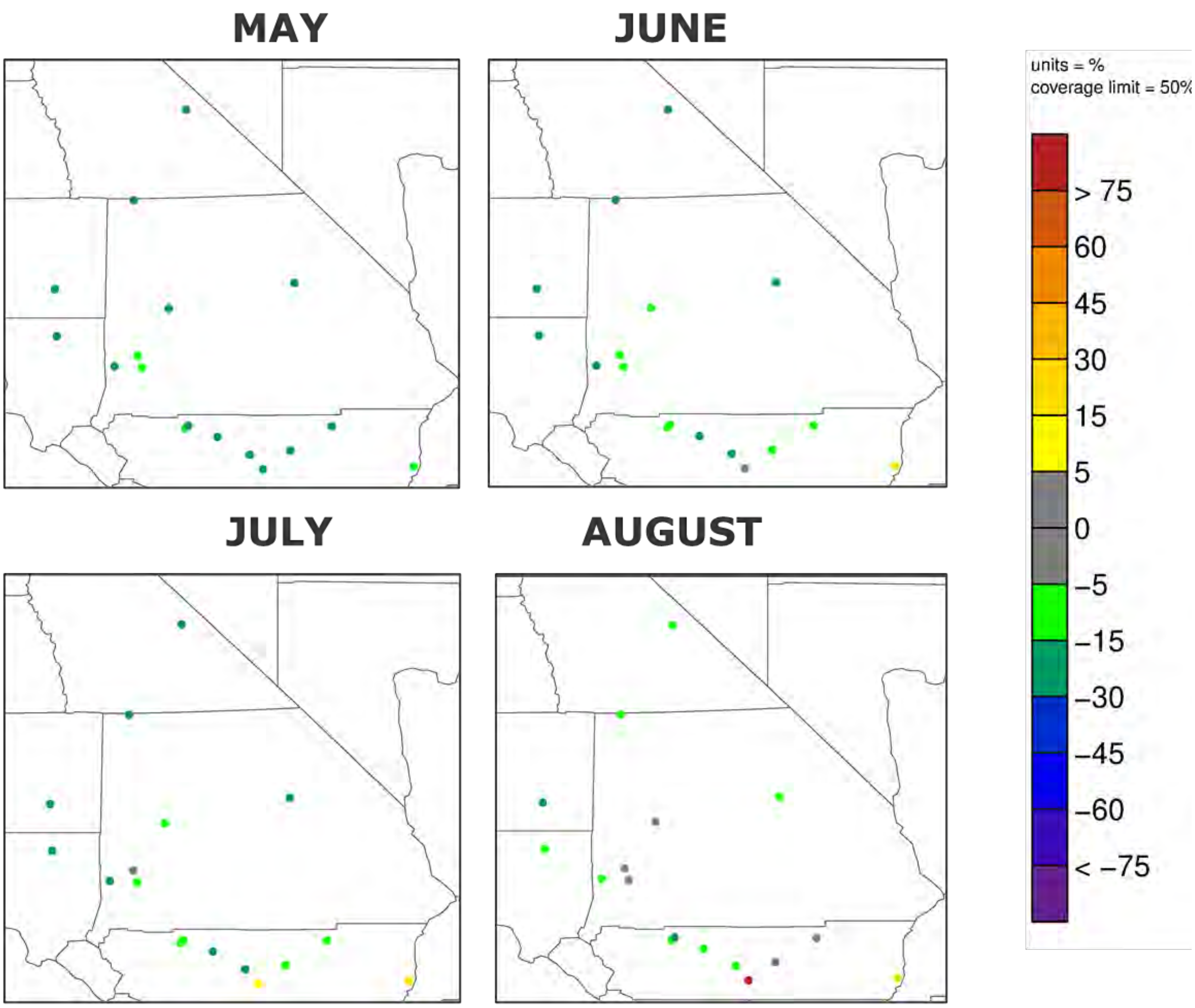


Figure 8-3. Map of site-specific monthly normalized mean bias (NMB) patterns for MDA8 ozone across the Mojave Desert of the southern California portion of the 12US2 domain.

Figure 8-4 presents time series of observed and simulated MDA8 ozone during the May through August modeling period at two representative monitoring sites. Whereas the model performed rather similarly over all LVV sites, Joe Neal (top panel) represents a site where the model performed more poorly during May through July, while Palo Verde (bottom panel) represents a site where the model performed better, though differences are subtle. The trend toward improving model-observation agreement from May to August is notable. Yet performance in replicating the highest peak days was not skillful in any month, and the model occasionally over predicted non-event dates in August (we revisit this issue later in this Section).

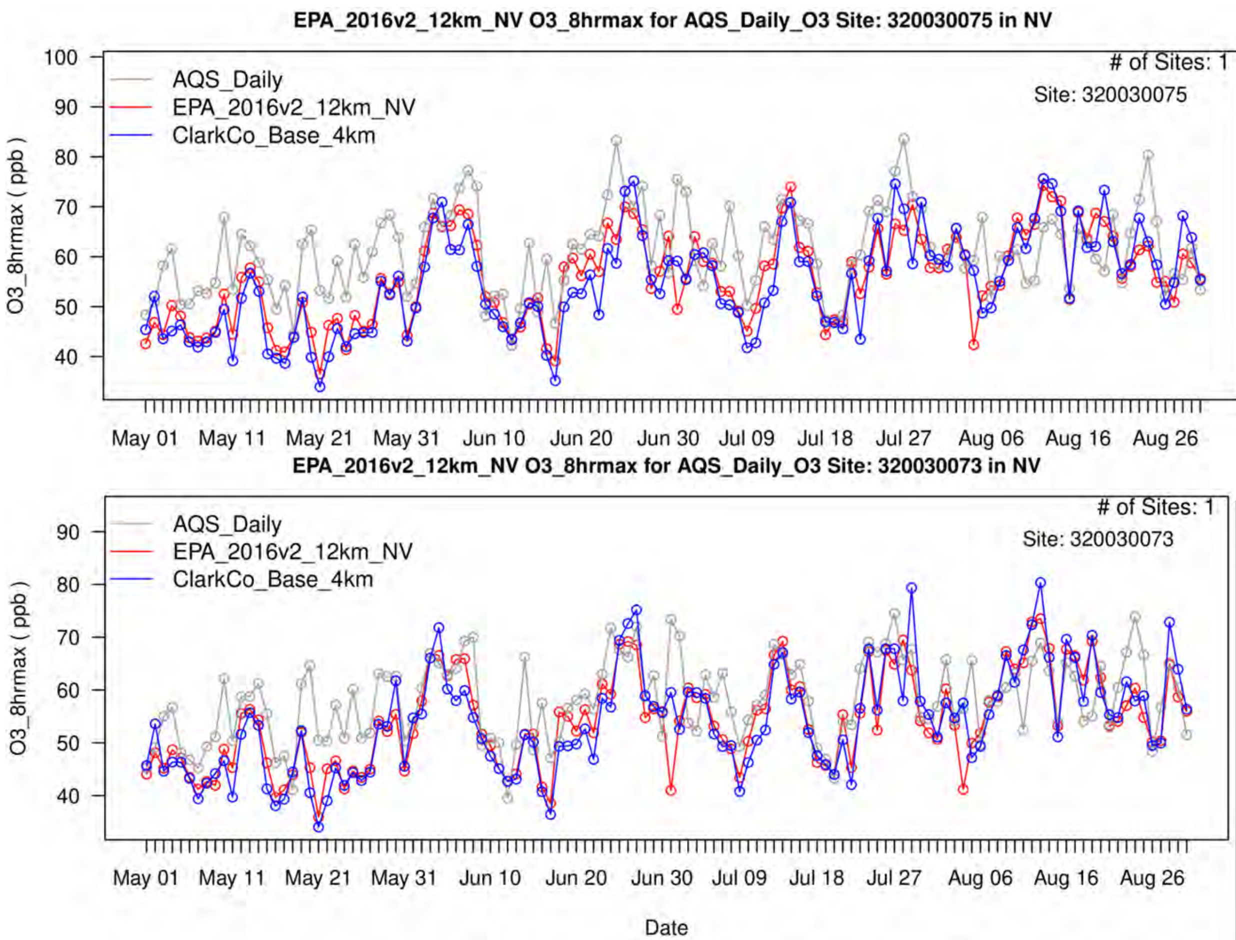


Figure 8-4. Time series of MDA8 ozone over the entire modeling period at the Joe Neal (top) and Palo Verde (bottom) monitoring sites. Daily AQS measurements are shown in grey, the modeled base case CC4c2 results are shown in blue, and EPA's results taken from their 2016v2 simulation on the 12US2 domain (EPA, 2022c) are shown in red.

Comparisons between the initial base case and the EPA 2016v2 12US2 results show that the current simulation tracked EPA's results very closely. This demonstrates that the introduction of the CC4c2 grid with its own emissions and meteorology had a minor influence on overall results. It further suggests that simulated ozone in the LVV were heavily influenced by a poor replication of regional ozone and transport into the LVV on the 12US2 grid (the inputs for which are identical to EPA's 2016v2 MP).

Scatter plots provide a way to visualize model-observation agreement over all days and sites. Figure 8-5 shows MDA8 ozone scatter plots separated by month for all sites within the CC4c2 grid. Again, the transition from under predictions in May to more balanced performance in August is evident. NMB characterizes the relative average difference between all points within the cloud and the 1:1 line that represent a perfect simulation. NME (unsigned error), R^2 (variance, or correlation R), and root mean square error (RMSE) are measures of the degree of scatter of the cloud. The amount of scatter was consistent from June through August and was consistent with or better than typical ozone model performance reported by Emery et al. (2016).

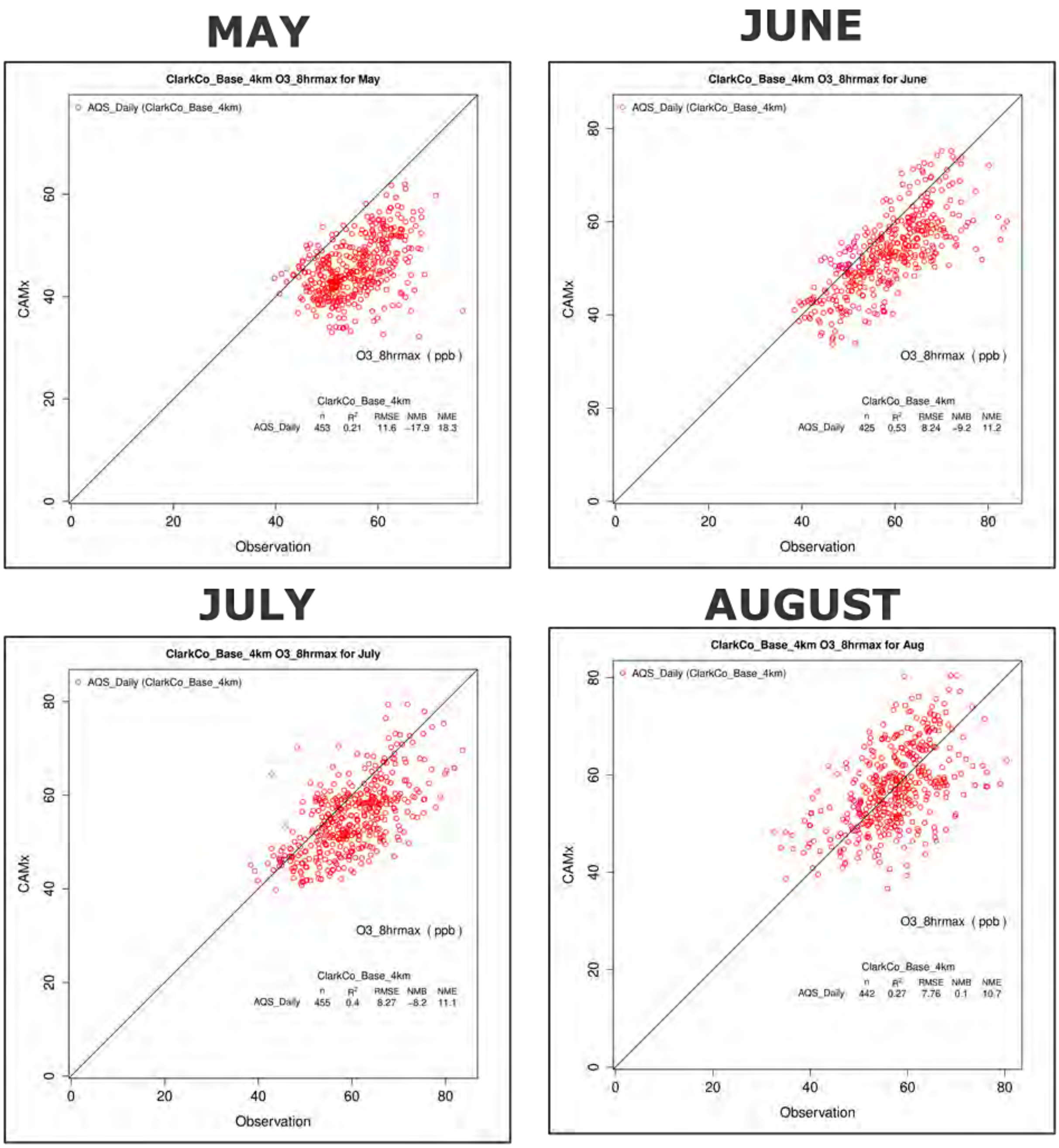


Figure 8-5. Monthly scatter plots of MDA8 ozone over all sites in the CC4c2 domain. Monthly statistics are also indicated on each plot and are described in the text.

Local ozone production depends on the amount of NO_2 available for photolysis and so it is important to assess simulated NO_2 performance against measurements. Figure 8-6 presents scatter plots of 1-hour NO_2 for all hours of the day and all 5 NO_2 monitoring sites within the LVV, arranged similarly to Figure 8-5 (see Figure 8-1 for the location of NOx monitors). The scatter plots show that NO_2 tended to be over predicted in May but transitioned to more under predictions from July through August. As will be shown below, the net bias represents a balance between large under predictions near roadway sites and large over predictions at other “neighborhood” sites. Nevertheless, the NO_2 downward bias trend is opposite from the upward ozone bias trend over the season. This suggests that modeled ozone production in the LVV increases with local NOx reductions (i.e., a NOx-disbenefit).

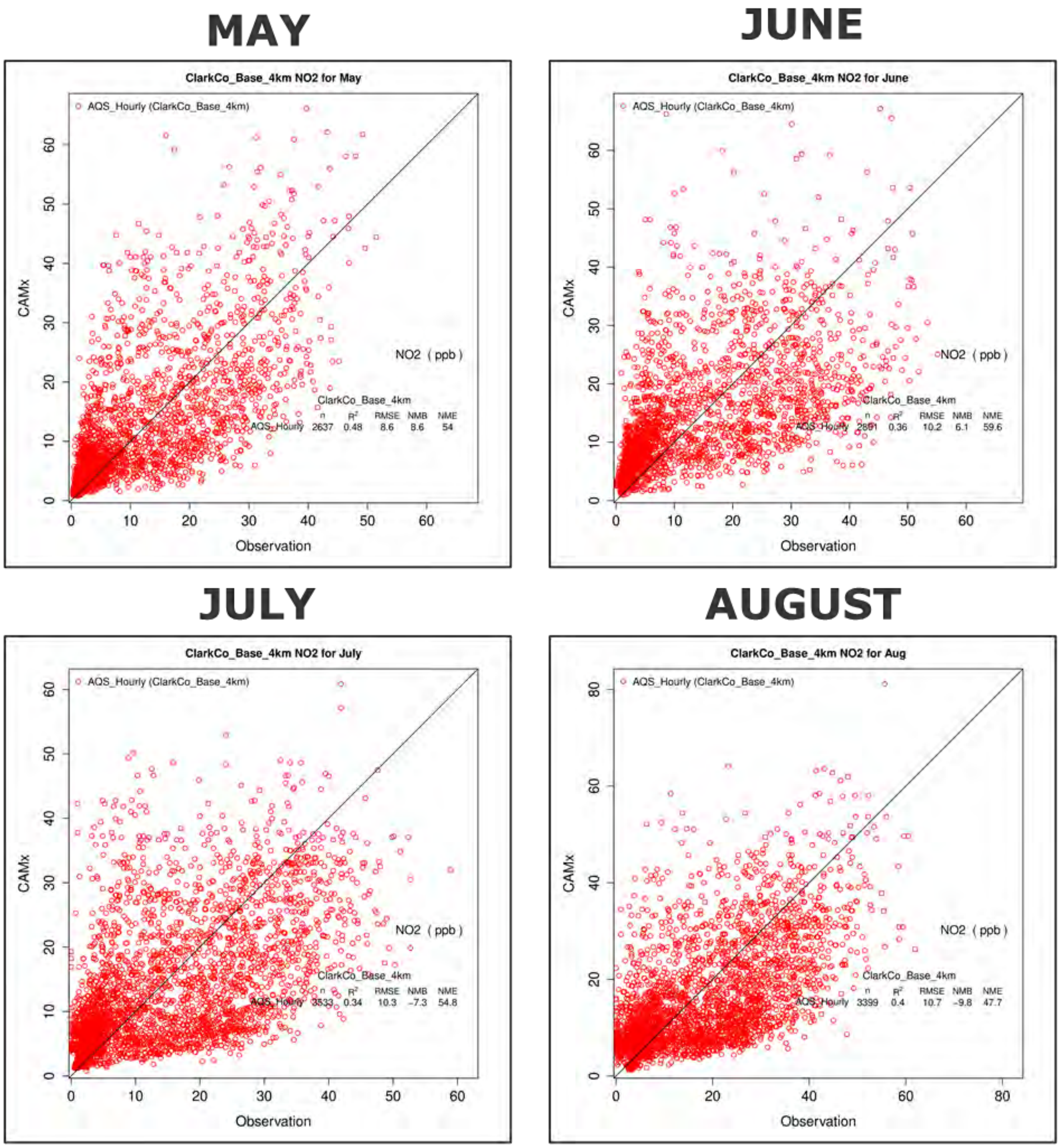


Figure 8-6. Monthly scatter plots of 1-hour NO_2 over all sites within the Las Vegas Valley. Monthly statistics are also indicated on each plot and are described in the text.

The degree of scatter, as visually evident and represented by the statistics on each plot, was rather large and NME consistently ranged from 50% to 60% over the period. This is typical of photochemical model performance for two reasons: (1) the model grid cannot spatially resolve primary NOx emissions at small sub-grid scales that monitors directly sense (near roads, point sources, etc.); (2) secondary NO_2 is derived from NO titration by ozone and local radical production, and so just like ozone, many processes involving emissions, chemistry, and meteorology must be properly simulated to achieve good NO_2 performance. It is therefore difficult to get good performance over all hours of the day, and especially at night when NOx concentrations peak in the stable, low mixing environment. The dependency of NOx performance on grid resolution is one particularly strong reason why no generalized and meaningful model performance benchmarks have been developed for NOx.

Observed time series of hourly NO_2 possess a high degree of noise from local influences, so model performance is difficult to visually interpret in that format. Instead, we used an AMET function to generate "box plots" of observed and predicted NO_2 concentrations that compare period-average and range for each hour of the day (Figure 8-7). The two sites in the top row of Figure 8-7 are located near freeways in central Las Vegas (see Figure 8-1). Here we would expect to see under predictions of NO_2, which was generally the case. The other three sites in Figure 8-7 show consistently large over predictions and ranges over all hours of the day, especially during morning and evening commute hours when emissions peak and the boundary layer is shallow. These features indicate either too much mobile source emissions allocated to commute hours and/or insufficient mixing depths, both of which are common issues seen in many other photochemical modeling exercises. Predicted NO_2 concentrations of 20 to 40 ppb during the early evening indicate ozone suppression via NO titration toward the end of the daily maximum 8-hour averaging period. Perhaps a more concerning issue is the very large over predictions during midday hours, when observations away from major roadways ranged over a few ppb while predicted NO_2 ranged closer to 10 ppb. This further suggests that the model was NOx-rich and inhibited daytime ozone production.

8.3.4 Analysis of Highest Observed Ozone Days

Table 8-5 ranks the highest observed ozone days exceeding 70 ppb during summer 2016 according to peak site concentrations in the LVV. Site- and date-paired model predictions are also listed for comparison. The table notes which days are expected to be influenced by regional wildfires versus local production and regional anthropogenic transport, according to previous analyses conducted by DES/DAQ.

Table 8-5 shows that most exceedance days were not well replicated, with typical under predictions of around 10 ppb. On only 8 of the 26 days listed, model-observation differences were within 5 ppb at these peak sites. Considering all days, the average peak observation was 75.4 ppb versus the average paired prediction of 64.7 ppb (absolute and normalized bias of -10.6 ppb and -14%, respectively). Results are similar when considering only days expected to be influenced by local production and regional transport. On those 9 days, the average peak observation was 75.1 ppb versus the average paired prediction of 63.4 ppb (absolute and normalized bias of -11.7 ppb and -16%, respectively).

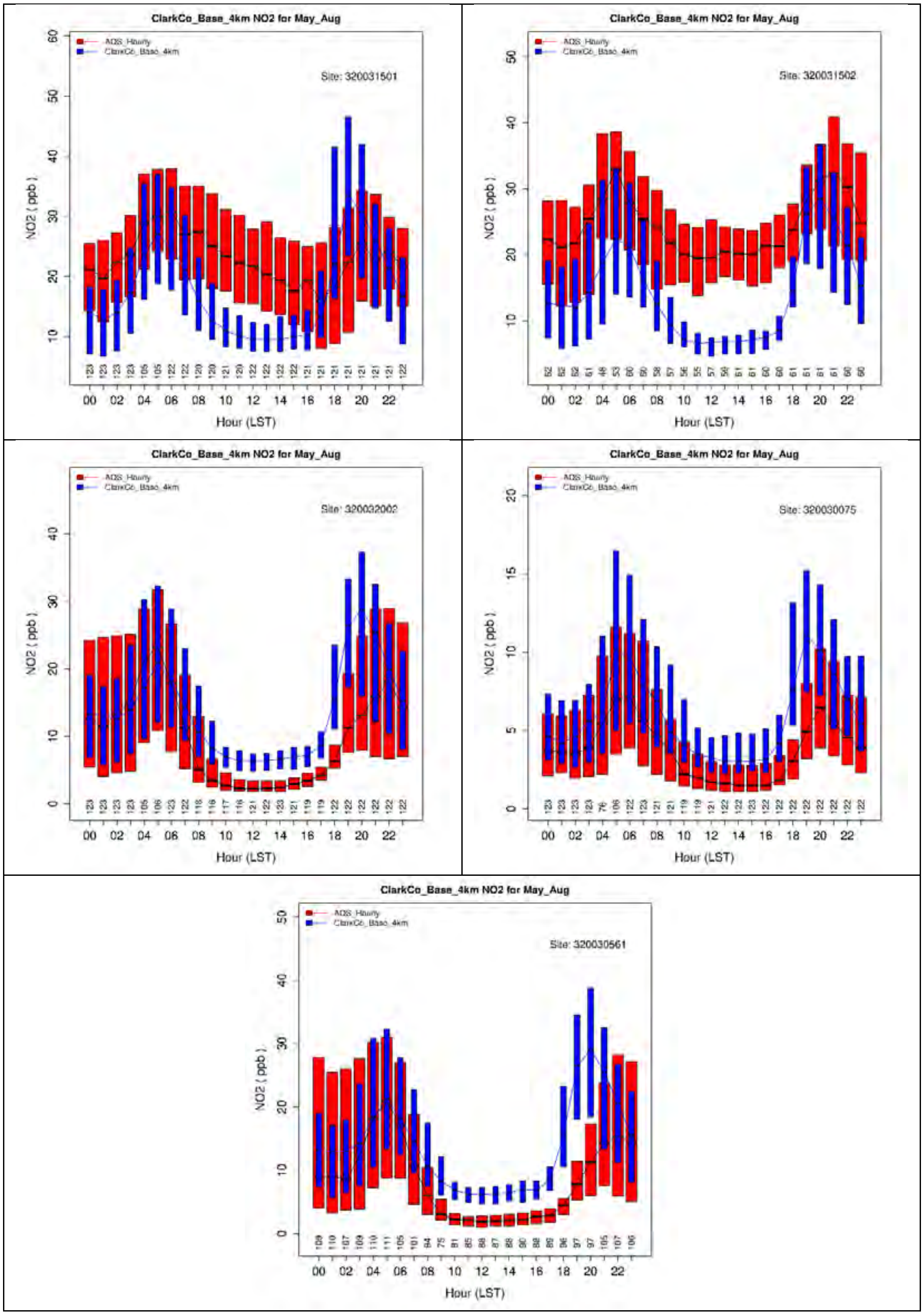


Figure 8-7. Diurnal box plots for observed (red) and predicted (blue) NO_2 at each hour of the day. Averages and ranges are determined over the entire May through August modeling period. "Near-Road" #1 and #2 sites (top row), J.D. Smith (left center), Joe Neal (right center), Sunrise Acres (bottom).

Table 8-5. Observed and predicted MDA8 ozone on days when at least one site monitored an exceedance above 70 ppb. The table shows the observed ozone at the peak site each day, ranked from highest to lowest, and the paired predicted values. Dates noted in red are expected to be influenced by regional wildfires. Dates noted in blue are expected to be caused mainly by local production and upwind transport from anthropogenic sources. Dates noted in black have not been assessed with respect to likely causes.

Site Name	Site ID	Date	Observed	Predicted	Difference
Apex	3200300221	6/24/2016	84.0	60.1	-23.9
Joe Neal	3200300751	7/27/2016	83.6	69.6	-14.1
Joe Neal	3200300751	8/24/2016	80.4	63.0	-17.4
LV Paiute	3200380001	7/1/2016	80.3	65.2	-15.0
LV Paiute	3200380001	6/7/2016	80.1	72.1	-8.1
LV Paiute	3200380001	7/26/2016	79.6	75.2	-4.4
LV Paiute	3200380001	6/8/2016	76.8	60.2	-16.5
SM Youth Camp	3200377714	5/20/2016	76.5	37.2	-39.3
LV Paiute	3200380001	8/23/2016	75.9	71.5	-4.4
Paul Meyer	3200300431	7/29/2016	75.5	77.9	2.4
LV Paiute	3200380001	7/2/2016	75.4	56.2	-19.2
LV Paiute	3200380001	6/25/2016	74.3	73.8	-0.5
Joe Neal	3200300751	6/27/2016	74.1	64.2	-9.9
LV Paiute	3200380001	6/3/2016	74.1	72.4	-1.7
Indian Springs	3200377721	7/25/2016	73.9	61.2	-12.7
Joe Neal	3200300751	6/6/2016	73.8	61.4	-12.4
SM Youth Camp	3200377714	8/25/2016	73.4	61.8	-11.5
Apex	3200320021	7/28/2016	73.0	59.7	-13.3
LV Paiute	3200380001	7/13/2016	73.0	71.3	-1.7
Joe Neal	3200300751	6/23/2016	72.4	61.6	-10.7
LV Paiute	3200380001	6/26/2016	72.4	73.9	1.5
LV Paiute	3200380001	7/14/2016	72.4	72.6	0.3
LV Paiute	3200380001	7/24/2016	72.3	62.2	-10.1
SM Youth Camp	3200377714	6/14/2016	71.5	50.7	-20.8
Paul Meyer	3200300431	8/13/2016	70.8	77.2	6.4
Joe Neal	3200300751	7/7/2016	70.1	50.3	-19.8

8.4 Sensitivity/Diagnostic Tests

These simulations involved assessing ozone impacts from modifying key inputs such as certain emission sectors, meteorological parameters, and chemistry inputs (i.e., mechanisms definitions, boundary conditions, etc.). Such tests help to elucidate sources of poor base case model performance as well as likely influences from future emission changes.

Six sensitivity tests were run that modified the initial 2016 base case configuration:

1. Include aerosols and associated chemical interactions, and elevate landing/takeoff operation (LTO) emissions from Harry Reid International Airport along typical 3-D departure and approach paths (SENS1);
2. Use results from a 2016 GEOS-Chem global chemistry model run (Ramboll, 2022c) to replace EPA's 2016 MP boundary conditions for the 36US3 domain, and run the 36US3 domain alone to develop alternative boundary conditions for the 12US2/CC4c2 domain (SENS2; otherwise, same as SENS1);

3. Conduct a series of short runs over June 20-27, a period of high observed ozone with mixed model performance, in which vertical diffusivity coefficient (Kv) profiles were altered to reduce and increase the rate of mixing at various times of the day (SENS3; otherwise, same as SENS1);
4. Use BEIS3.6/BELD4 biogenic emissions from the 2016v1 MP on the 12US2 domain (without the CC4c2 grid) to investigate LVV ozone sensitivity (SENS4; otherwise, same as the initial base case);
5. Use the latest BEIS4/BELD6 biogenic emissions on the 12US2/CC4c2 grids to investigate LVV ozone sensitivity (SENS5; otherwise, same as SENS1);
6. Use results from a 2016 CAM-Chem global chemistry model run (NCAR, 2022) to replace EPA's 2016 MP boundary conditions for the 36US3 domain, and run the 36US3 domain alone to develop alternative boundary conditions for the 12US2/CC4c2 domain (SENS6; otherwise, same as SENS5).

8.4.1 SENS1 Approach

Independent CAMx testing previously conducted by Ramboll indicated that inclusion of aerosols in the photochemical simulation impacts ozone concentrations to varying degrees depending on many factors, but typically the effect remains within 3-5 ppb regionally. Aerosols influence photolysis rates by altering the scattering and absorption of solar radiation. Additionally, aerosols play an important role in the chemical processing of nitrogen oxides and their products (i.e., "NOz"), a portion of which ultimately feeds back to ozone production at regional scales. Given that EPA ran their 2016v2 MP with aerosols, we decided in SENS1 to test the impact of including aerosols on ozone model performance in the LVV.

The base case model performance evaluation described above showed a tendency to over predict NOx (as NO_2) in the central LVV. The 2016 base year emissions processing placed all airport sector emissions into the single surface grid cell that each airport occupies. While most Clark County airports are not major emission sources, Harry Reid (formally McCarran) International Airport is a major source situated near central Las Vegas. Total 2017 emissions from Reid Airport were estimated to be: 2371 TPY CO, 403 TPY VOC, and 3618 TPY NOx. Of these totals, LTOs comprised 19% CO, 14% VOC, and 68% NOx (2443 TPY). Expecting that the large amount of LTO NOx within a single surface grid cell contributed to overestimates at the central LVV NOx monitors, we developed a program to elevate model-ready LTO emissions to higher model layers along assumed typical departure and approach paths, resulting in a vertical "V" shaped emissions profile centered on the Reid Airport surface grid cell. As a result, this modification removed 7.5 TPD NOx from the Reid Airport cell during a typical summer weekday.

Separate vertical profiles were determined for departure and approach segments. For departure, we applied a typical average climb rate of 2250 feet/minute (i.e., between 2000 and 2500 feet/minute) at 250 knots. We assumed a straight-out departure from runway 26R through 10,000 feet (~3 km – roughly the depth of the maximum afternoon boundary layer). For approach, we applied a typical average decent rate of 1000 ft per 3 nautical miles (1388 feet/minute at 250 knots). We also assumed a straight-in final approach to runway 26L from 10,000 feet. Certain details in our approach deviate from the actual Reid Airport flight pattern, but the purpose of the exercise was to remove LTO emissions from the single 20 m deep grid cell and distribute them three-dimensionally in an arguably realistic manner. A program was constructed that allocates fractions of total model-ready hourly, speciated LTO emissions to each cell along the V-shaped pattern. Resulting emissions were written to a CAMx 3-D emissions input file.

8.4.2 SENS2 Approach

SENS2 was conducted to assess how the source of global boundary conditions influence simulated ozone in the LVV. The EPA developed boundary conditions for their 36US3 domain from a 2016 hemispheric application of the Community Multiscale Air Quality (CMAQ) photochemical model (EPA, 2022a). EPA ran the 36US3 domain separately, then extracted resulting 3-D concentrations for all chemical species to generate boundary conditions for the 12US domain, which EPA ran for all of their subsequent analyses. For SENS2, Ramboll developed a new set of 36US3 boundary conditions from a preexisting 2016 GEOS-Chem dataset generated during our projects supporting the Denver ozone SIP (Ramboll, 2022c). Following EPA's approach, we ran the 36US3 with the alternative boundary conditions, then extracted new 12US2 boundary conditions for the April-August modeling period. The 12US2/CC4c2 grid system was then rerun to complete SENS2. Otherwise, SENS2 was configured the same as SENS1.

8.4.3 SENS3 Approach

SENS3 involved several short tests during late June 2016 in which Kv vertical profiles were altered to reduce the rate of daytime mixing through the boundary layer without altering the depth of mixing. According to aerosol backscatter profiles measured during a summer 2021 field study (NOAA, 2022), the deep afternoon boundary layer is not uniformly well mixed, but instead consistently exhibits vertical pollutant gradients. We postulated that WRF-derived Kv profiles are perhaps too large, over mixing the boundary layer, rapidly resulting in uniform ozone and precursor profiles, and thereby contributing to under predictions of surface ozone. In each test, varying amounts of Kv reductions were applied within the daytime boundary layer. In a separate test, we raised the minimum boundary layer depth during nighttime and morning hours to 300 m in an attempt to reduce the degree of NOx over predictions during commute hours and to assess impacts on ozone production rates. Otherwise, all SENS3 tests were configured the same as SENS1.

8.4.4 SENS4 Approach

SENS4 replaced BEIS3.7/BELD5 biogenic emissions from the 2016v2 MP with BEIS3.6/BELD4 biogenic emissions from the 2016v1 MP. Results from the initial base case indicated that simulated isoprene concentrations often exceeded 1 ppb within the LVV during the daytime. These represent large over predictions relative to 2021 field study measurements (NOAA, 2022) that indicate isoprene should range over a few tenths of a ppb. EPA's analyses undertaken for Denver (Ramboll, 2022c) showed that western statewide biogenic isoprene emissions from BEIS3.6 are about twice as high as BEIS3.7 but urban emissions are lower. Only the 12US2 domain was run for this test as BEIS3.6/BELD4 biogenic emissions from the 2016v1 MP were readily available on that grid. Otherwise, SENS4 was configured the same as the initial base case, with no aerosols and no adjustment to Reid Airport LTO emissions since that was applied only on the CC4c2 grid.

8.4.5 SENS5 Approach

SENS5 replaced BEIS3.7/BELD5 biogenic emissions with the latest BEIS4/BELD6 biogenic emissions platform. Reports from EPA's early testing for the western US (Ramboll, 2022c) indicated that BEIS4 resulted in lower biogenic emissions than BEIS3.6. EPA graciously processed BELD6 vegetative cover datasets for the 12US2 and CC4c2 grids for our use with BEIS4. Ramboll processed BEIS4 biogenic emissions on the 36US3/12US2/CC4c2 grid system for the entirety of the April-August modeling period and ran CAMx with the same configuration as SENS1.

8.4.6 SENS6 Approach

SENS6 was conducted to assess another alternative source of global model boundary conditions. The Community Atmosphere Model with Chemistry (CAM-chem) is a component of the NCAR Community

Earth System Model (CESM) and is used for simulations of global tropospheric and stratospheric atmospheric composition (NCAR, 2022). CAM-chem uses the MOZART chemical mechanism, with various choices of complexity for tropospheric and stratospheric chemistry. CESM2, including CAM6-chem, is the current version. NCAR has run CAM-Chem and archives 6-hourly output on a ~1 degree resolution global grid from January 1, 2001 to December 31, 2020. Portions of the grid can be downloaded from NCAR for chemical model downscaling to support regional applications (Buchholz et al., 2019).

Ramboll developed a new set of 36US3 boundary conditions from existing 2016 CAM-Chem datasets archived at NCAR (NCAR, 2022). We developed graphical comparisons of ozone fields across North America and at several altitude from GEOS-Chem and CAM-Chem and noted that the latter simulated much higher ozone patterns throughout the mid- and upper-troposphere (3-8 km) over the western US. Anticipating that this additional mid-level ozone may help to alleviate large regional ozone under predictions across the western US, we ran the 36US3 grid with the alternative boundary conditions, then extracted new 12US2 boundary conditions for the April-August modeling period. The 12US2/CC4c2 grid system was then rerun to complete SENS6. Otherwise, SENS6 was configured the same as SENS1 and SENS5 using BEIS4 on all three grids.

8.4.7 Summary of Results

Results from the 2016 sensitivity cases are summarized below:

- In SENS1 and SENS2, MDA8 ozone continued to be under predicted for most sites and months, and performance statistics showed successively worse performance in both tests.
  - Both sensitivity runs had little influence on basin-wide and regional ozone.
  - SENS1 with elevated Reid Airport emissions showed filling of a local ozone hole in that area caused by high NOx emissions.
  - SENS1 with aerosols resulted in consistent 1-3 ppb decreases in background concentrations entering the LVV.
  - SENS2 with alternative 36US3 boundary conditions showed generally lower background concentrations entering the LVV relative to both the initial base case and SENS1.
  - Under prediction bias continued to be relatively larger on high observed ozone days (>60 ppb).
- In SENS1 and SENS2, NO_2 continued to transition to lower ambient concentrations from May to August.
  - Elevating Reid Airport emissions in SENS1 reduced surface NO_2, resulting in a near zero bias in May to -18% bias in August, which was more expected given the inability of the grid to resolve local NOx emissions.
  - The SENS1 impact to diurnal NO_2 concentrations was substantial during certain hours of the day with largest reductions at sites closest to Reid Airport, especially during the daytime and evening commute hours.
  - Elevating Reid Airport LTO emissions away from the surface grid cell was appropriate.
- All SENS3 tests with reduced rates of vertical mixing usually resulted in substantially lower regional and local ozone.
  - Lower Kv resulted in a clear inhibition of local ozone production due to enhancing near-surface buildup of NOx concentrations in the central LVV.
  - Lower Kv resulted in a widespread reduction in downward mixing of higher regional ozone concentrations aloft.

- A SENS3 test that raised Kv such that that the boundary layer depth would never decrease below 300 m during the night and morning hours resulted in no effects to NOx or ozone during daylight hours when vertical mixing far exceeded the 300 m minimum.
  - Deeper mixing between 8 PM and 6 AM reduced NOx concentrations in the central LVV substantially, but those reductions had no impact on morning or daytime NO_2 or ozone production.
- Use of BEIS3.6/BELD4 biogenic emissions on the 12US2 grid in SENS4 greatly increased ozone in the LVV and improved statistical performance during June-August to within benchmark goals.
  - BEIS3.6/BELD4 generated higher rural biogenic isoprene emissions but lower urban emissions that better agree with 2021 field measurements in central Las Vegas.
  - However, the regional under prediction bias across the California transport corridor was not as dramatically affected, perhaps because of the NOx-limited, VOC-lean conditions there. Biogenic isoprene also can react with and destroy ozone, balancing the low ozone production rates in rural areas.
  - Given the much higher rural VOC emissions, use of coarse resolution, and some large MDA8 ozone over predictions during June-August, we were concerned that the much higher ozone resulting from BEIS3.6/BELD4 led to a model that performs better but for the wrong reason.
- Use of BEIS4/BELD6 biogenic emissions in SENS5 did not markedly change ozone performance in the LVV or over the wider region relative to SENS1 and led to under predictions of isoprene in the LVV.
  - BEIS4/BELD6 generated much lower rural and urban biogenic isoprene emissions than both BEIS3.6 and BEIS3.7.
  - The lack of regional impact across the California transport corridor was again most likely a result of NOx-limited, VOC-lean conditions there.
- The use of CAM-Chem BCs in SENS6 led to markedly improved regional and urban ozone performance during May and June, but similar performance to SENS5 during July and August.
  - Under prediction bias continued to be relatively larger on high observed ozone days (>60 ppb) but most months were within statistical benchmarks.
- Overall, the evaluation of initial base year model performance indicates:
  - A lack of regional ozone buildup and transport into the LVV that is ameliorated during the spring and early summer by the use of alternative boundary conditions representing North American background ozone;
  - A strong sensitivity to rural rather than urban biogenic VOC emissions;
  - Local NOx-heavy chemistry (ozone inhibition and potential NOx disbenefit);
  - Relative quantities of ozone and NOx change over the summer, leading to better performance for both compounds in August.

8.4.8 Results from Sensitivity Tests 1 and 2

Table 8-6a lists monthly NMB and NME statistical performance for MDA8 ozone over all days and all ozone monitoring sites within the CC4c2 domain. The table compares results from the Clark County base case and both sensitivity runs. NMB and NME are color coded for visual reference to statistical goals and criteria benchmarks.

Performance among all simulations was very similar, showing a consistent and systematic negative bias over all months. A rather large negative bias outside of the criteria benchmark occurred in May, followed by a transition to smaller bias through August well within the statistical goal. The sensitivity tests resulted in a progressively larger bias and error relative to the initial base case.

Table 8-6. Monthly model performance statistics for MDA8 ozone over all days and all ozone monitoring sites within the CC4c2 domain that operated during the summer of 2016. Normalized mean bias (NMB) and normalized mean unsigned error (NME) are shown with color coding indicating statistics outside performance criteria (red), between goals and criteria (yellow) and within goals (green). Results from the Clark County initial base case and two sensitivity cases are compared.

Month	MDA8 Ozone (no cutoff)					
	NMB (%)			NME (%)		
	BASE	SENS1	SENS2	BASE	SENS1	SENS2
May	-17.9	-19.5	-18.5	18.3	19.6	18.7
June	-9.2	-9.4	-12.1	11.2	11.2	13.3
July	-8.2	-8.6	-11.6	11.1	11.2	13.5
Aug	0.1	-1.2	-4.6	10.7	10.9	9.6
May-Aug	-8.8	-9.7	-11.7	12.8	13.2	13.8

Table 8-6b presents the same information but limited to sites and days when observed MDA8 ozone exceeded 60 ppb. Similar patterns are evident on high ozone days, with again progressively worse performance in the sensitivity tests. The overall monthly statistical results shown in these tables apply consistently across all CCNAA monitoring sites, with no single sites indicating substantially worse or better statistical performance than the initial base case.

Table 8-6b. As in Table 8-6a, but for all sites and days when monitored MDA8 ozone exceeded 60 ppb.

Month	MDA8 Ozone (60 ppb cutoff)					
	NMB (%)			NME (%)		
	BASE	SENS1	SENS2	BASE	SENS1	SENS2
May	-21.5	-22.5	-21.6	21.5	22.5	21.6
June	-11.3	-11.4	-12.9	12.7	12.7	13.9
July	-11.7	-12.0	-14.7	12.7	12.8	15.3
Aug	-4.3	-5.3	-8.8	11.4	12.0	11.0
May-Aug	-11.5	-12.1	-14.0	13.9	14.2	15.0

Figures 8-8 and 8-9 present spatial maps of site-specific monthly NMB from the SENS1 and SENS2 cases, respectively, for selected monitoring sites across the Mojave Desert of Southern California. The plots show the same general pattern of systematic negative bias and month-by-month improvement through August as the initial base case (Figure 8-3). The under prediction bias remained much larger than the LVV sites and slightly larger than the initial base case. This continued to implicate a lack of regional ozone and associated transport as a likely contributor to poor performance in the LVV, despite the use of alternative boundary conditions. Therefore, model performance across Southern California and within the LVV was not sensitive to the inclusion of aerosol chemistry or the use of GEOS-Chem as the source of global background as represented by boundary conditions.

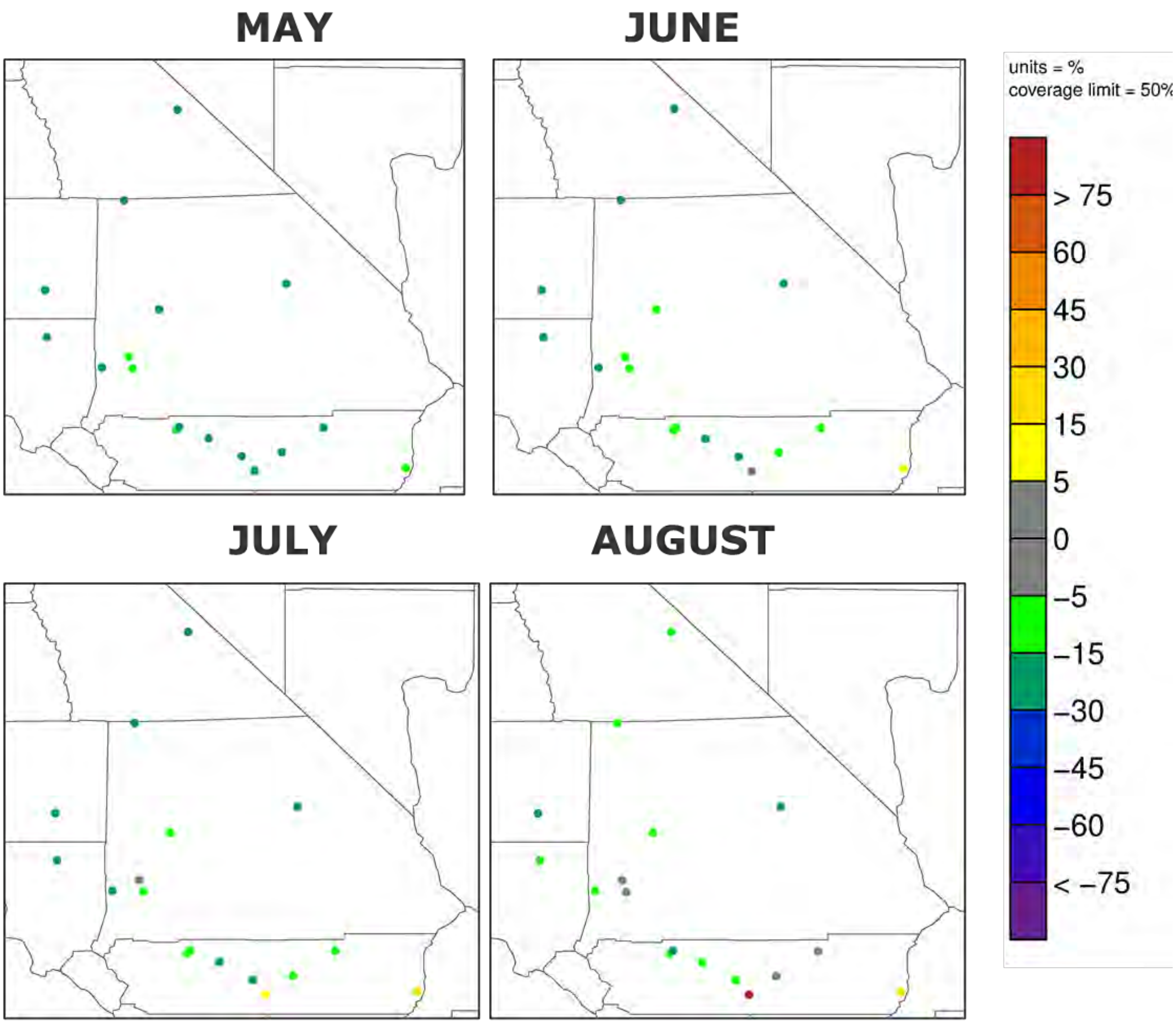


Figure 8-8. Map of site-specific monthly normalized mean bias (NMB) patterns for MDA8 ozone in the SENS1 case across the Mojave Desert of the southern California portion of the 12US2 domain.

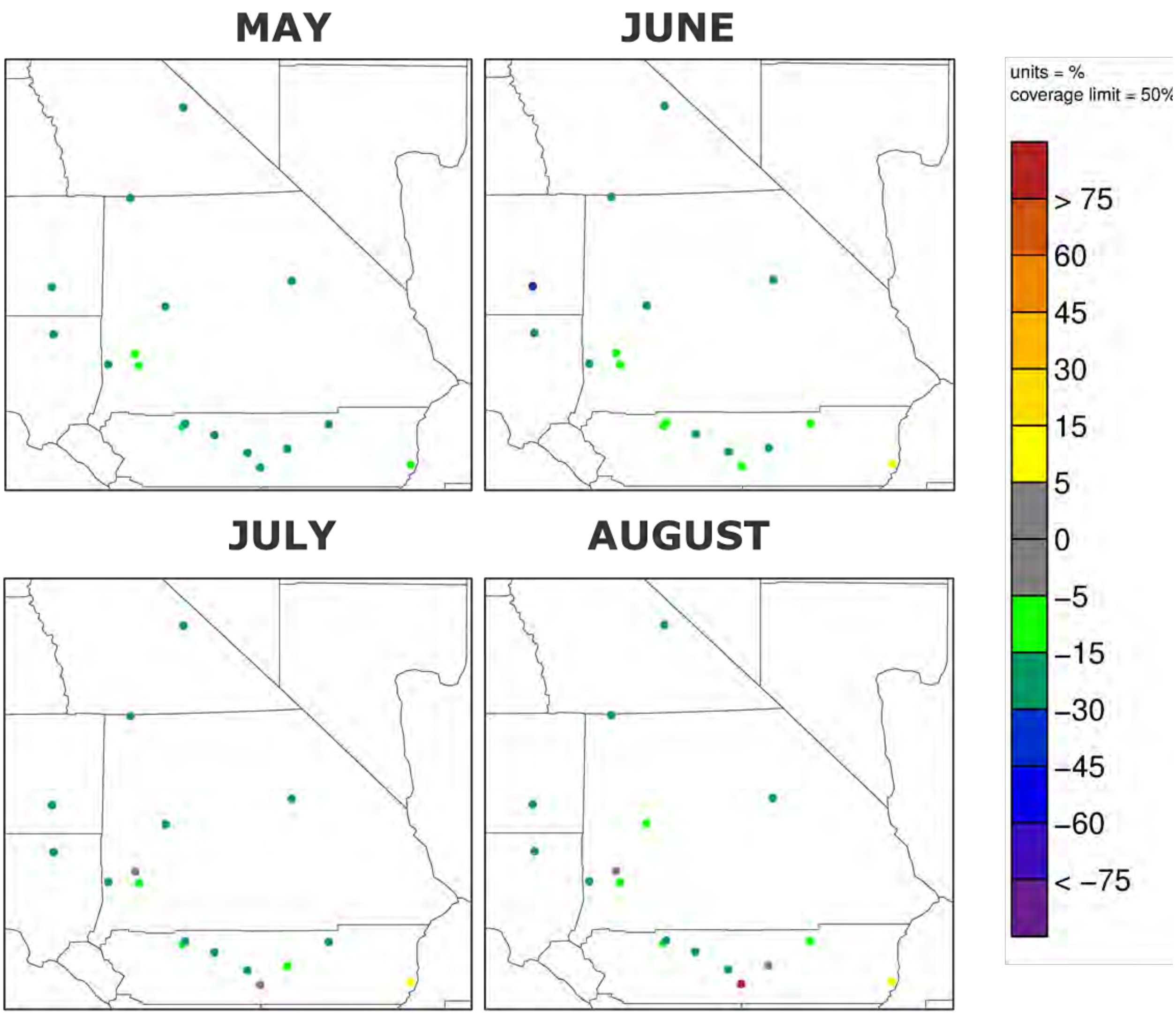


Figure 8-9. Map of site-specific monthly normalized mean bias (NMB) patterns for MDA8 ozone in the SENS2 case across the Mojave Desert of the southern California portion of the 12US2 domain.

Figure 8-10 presents time series of observed and simulated MDA8 ozone during the May through August modeling period at the Joe Neal monitoring site. The initial base case is shown in blue and the sensitivity cases are shown in red (SENS1 in top panel, SENS2 in bottom panel). The base case and SENS1 predicted nearly identical ozone results, with periods when SENS1 was slightly lower. SENS2 resulted in consistently lower ozone throughout the summer due to alternative boundary conditions and lower regional ozone. Figure 8-11 shows time series at the Palo Verde site with very similar results.

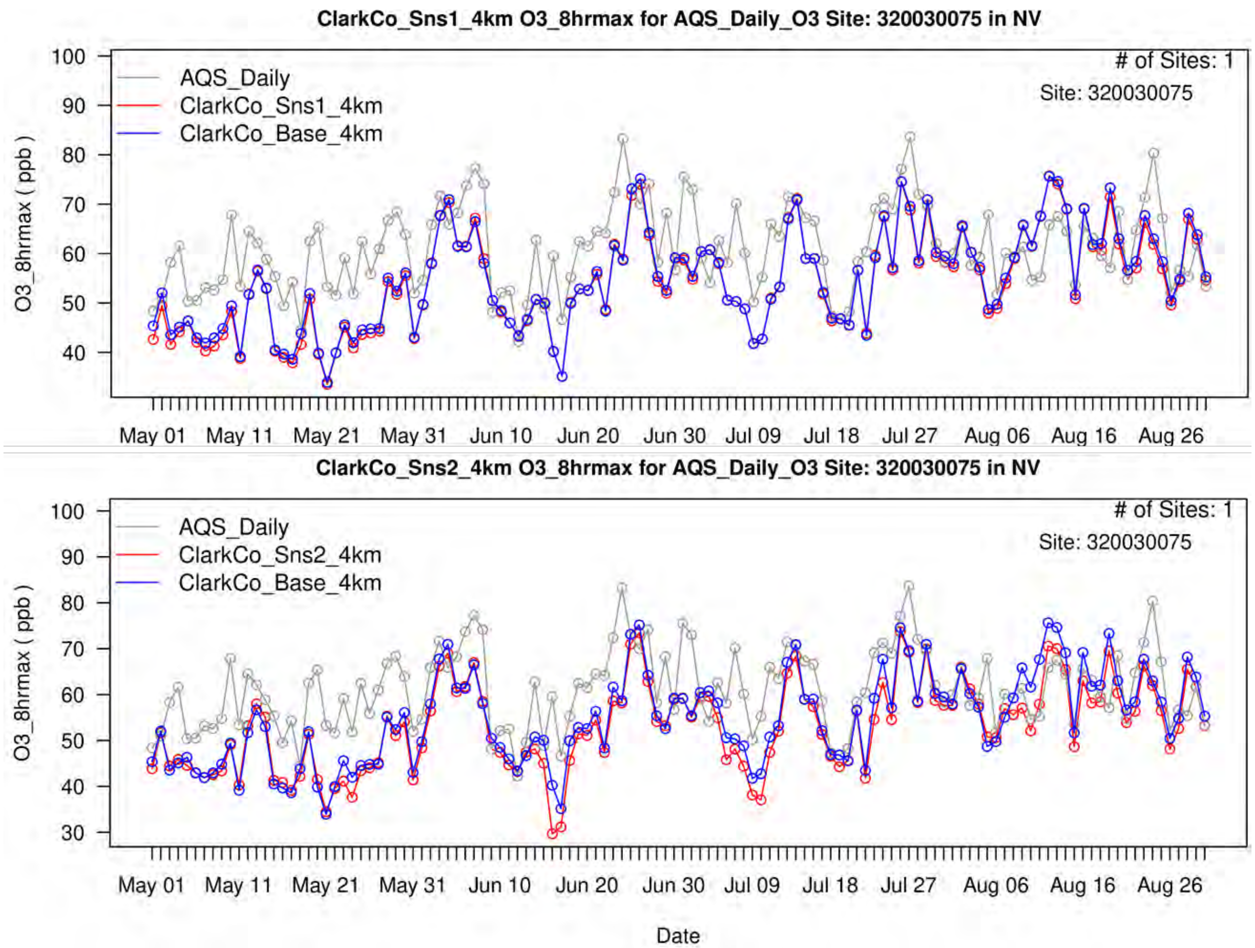


Figure 8-10. Time series of MDA8 ozone over the entire modeling period at the Joe Neal monitoring site. Daily AQS measurements are shown in grey, the modeled base case results are shown in blue, and the SENS1 (top) and SENS2 (bottom) results are shown in red.

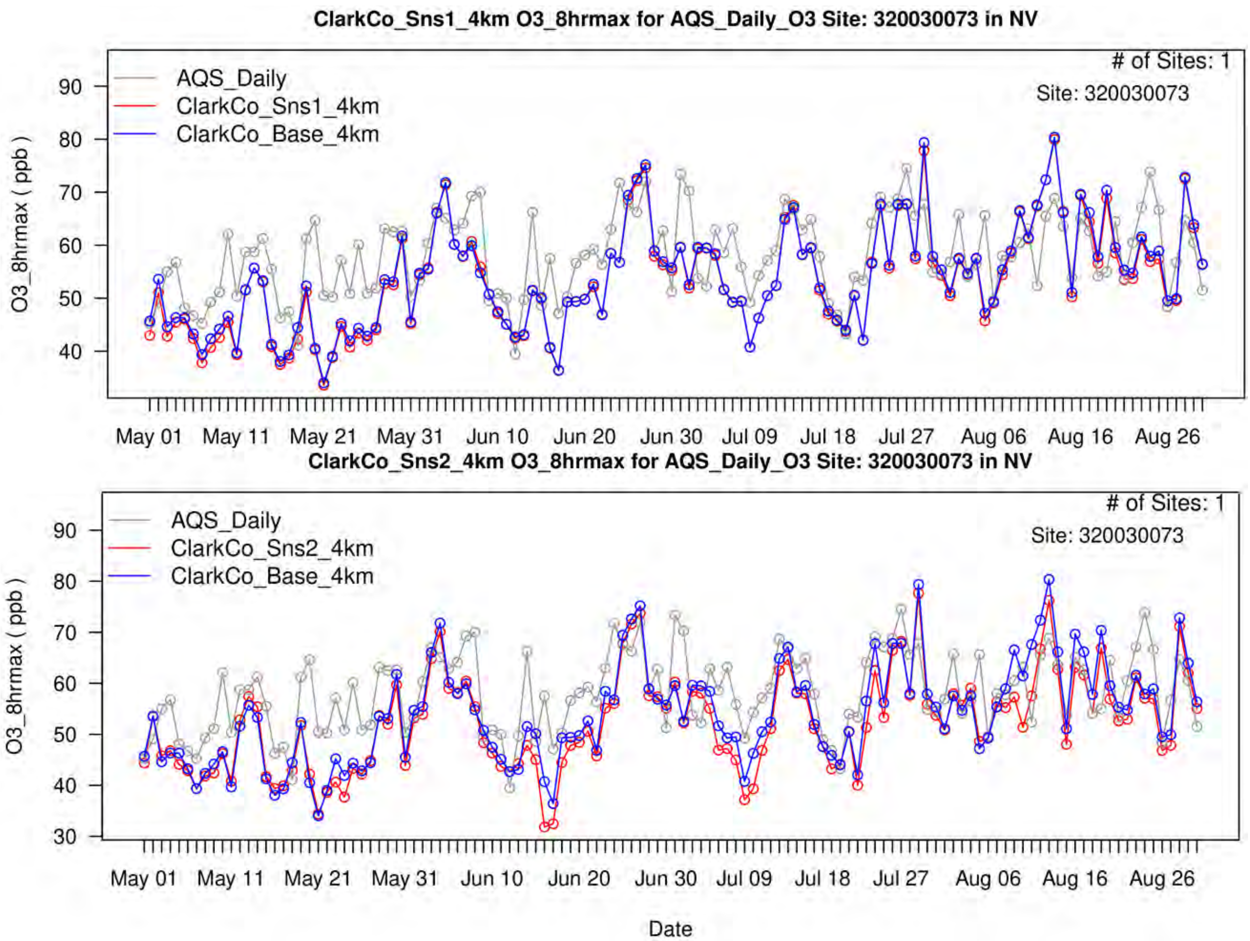


Figure 8-11. Time series of MDA8 ozone over the entire modeling period at the Palo Verde monitoring site. Daily AQS measurements are shown in grey, the modeled base case results are shown in blue, and the SENS1 (top) and SENS2 (bottom) results are shown in red.

Scatter plots of 1-hour NO_2 from the SENS1 case (not shown) show the same general patterns as the initial base case, but the largest over predictions were reduced 10-20 ppb in SENS1 due to the elevation of LTO emissions. The lower NO_2 concentrations resulted in a bias transition from about zero in May to -18% in August. We expected a tendency for consistent under predictions given the inability of the grid to resolve local NOx emissions, so these results conformed to expectations. Normalized errors (degree of scatter) remained in the range of 50% to 60% and correlations remained low for the period.

Figure 8-12 shows box plots of observed and predicted diurnal NO_2 concentrations in the SENS1 case, arranged similarly to Figure 8-7 that displays initial base case results (note different concentration scales among these plots). Diurnal prediction patterns were similar to the base case, but NO_2 reductions were notable at sites nearest Reid Airport (near-road sites and Sunrise Acres). At these sites, the largest reductions occurred during the evening commute hours, and midday NO_2 concentrations decreased from near 10 ppb to closer to 5 ppb.

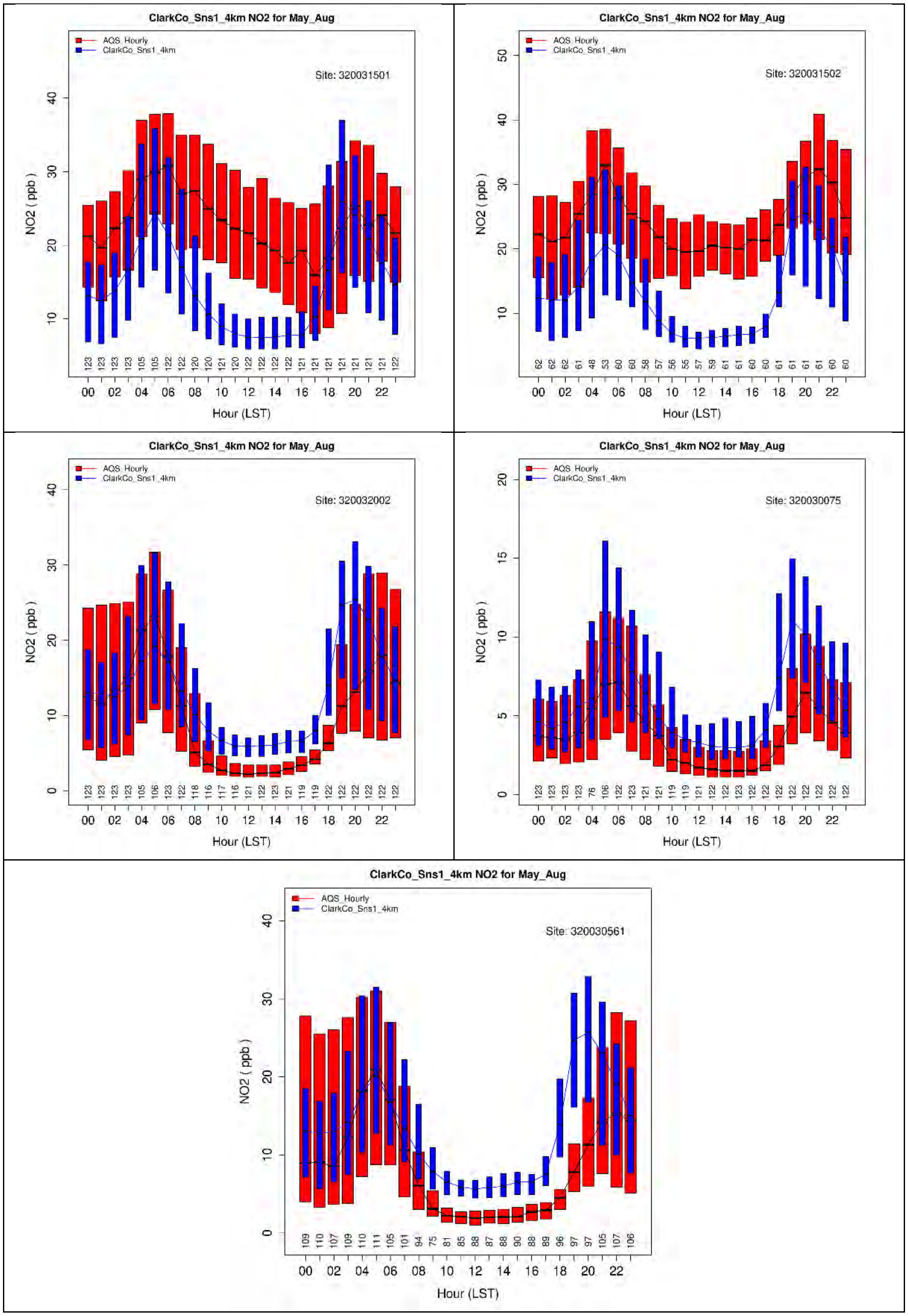


Figure 8-12. Diurnal box plots for observed (red) and SENS1 predicted (blue) NO_2 at each hour of the day. Averages and ranges are determined over the entire May through August modeling period. "Near-Road" #1 and #2 sites (top row), J.D. Smith (left center), Joe Neal (right center), Sunrise Acres (bottom).

However, there continued to be a strong tendency to over predict at sites not situated near major roadways, especially during evening commute hours. Continued over predicted NOx concentrations of 20 to 30 ppb during the evening likely suppressed ozone toward the end of the daily maximum 8-hour averaging period. These features continued to indicate problems with the characterization of mobile source emissions and/or perhaps insufficient mixing depths. However, these results confirmed that elevating Reid Airport LTO emissions away from the surface grid cell was appropriate.

8.4.9 Sensitivity to Vertical Mixing

Figure 8-13 shows an example of Doppler lidar aerosol backscatter and turbulence intensity above North Las Vegas airport in August 2021 reported by NOAA (2022). These types of plots provide valuable qualitative information about the structure of the summer daytime boundary layer. The diagnosed boundary layer height extended above 3 km, in agreement with WRF results used in this study. Measurements showed that the daytime boundary layer was not uniformly well mixed, but instead it consistently exhibited gradients in vertical pollutant profiles (left) and turbulent mixing rates (right).

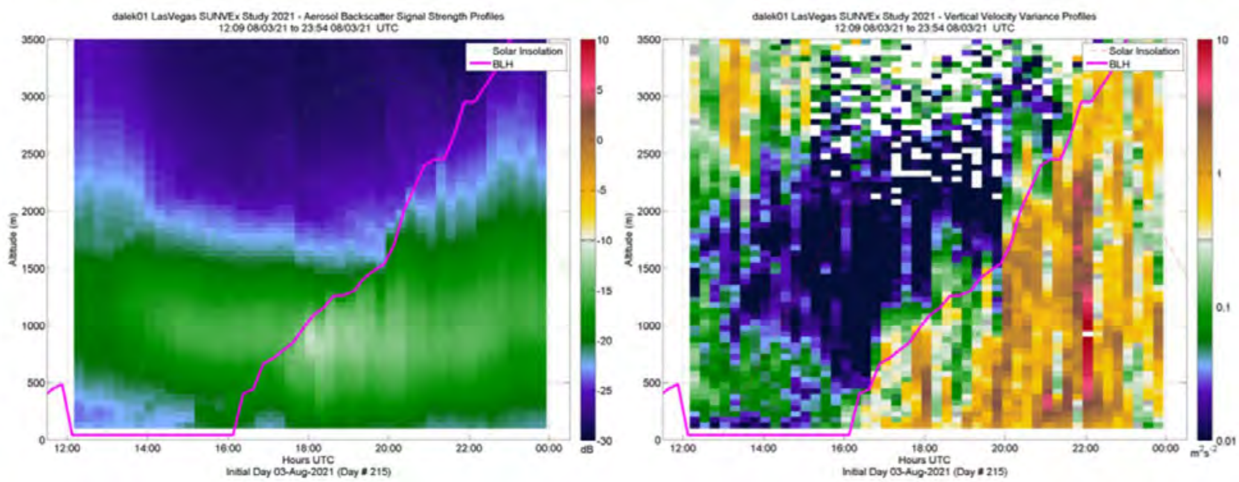


Figure 8-13. Example 15-minute time-height cross sections from Doppler lidar profiles of aerosol backscatter (dB, left) and turbulent intensity (m^2/s^2, right) on an August day in 2021. An estimate of the boundary layer height is shown as the magenta line (taken from NOAA, 2022).

In each of four diffusivity tests conducted under SENS3, we applied varying amounts of Kv reduction within the daytime boundary layer. Yet all tests resulted in substantially lower regional and local ozone. Reduced Kv rates resulted in a clear inhibition of local ozone production due to the near-surface buildup of NOx concentrations in the central LVV. Reduced Kv rates also resulted in a widespread reduction in downward mixing of higher regional ozone concentrations aloft. Therefore, we provide only one example of SENS3 results below for illustrative purposes.

Figure 8-14 shows the spatial pattern of MDA8 ozone on June 24, a day with peak observed MDA8 ozone of 84 ppb at Apex to the northeast of Las Vegas but very low predicted ozone across the LVV. The effects from reduced Kv on this day were typical of all other days and tests: regional ozone was substantially lower than the base case, and the base case ozone hole over central Las Vegas was larger and deeper. Since these tests disproved our hypothesis that reduced Kv might increase surface ozone by limiting mixing rates, and effectively reducing the net mixing volume, we did not pursue our investigation further.

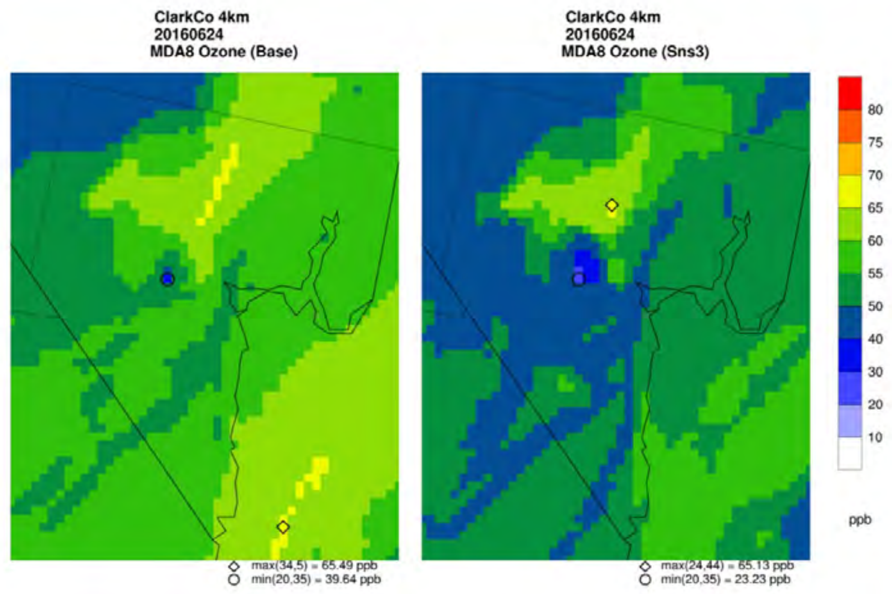


Figure 8-14. Spatial distribution of MDA8 ozone on June 24, 2016 from the base case (left) and from a SENS3 Kv reduction case (right).

Another Kv sensitivity test was performed in which we configured the diffusivity inputs in such a way that boundary layer depth would never decrease below 300 m during the night and morning hours. This test investigated the role of vertical mixing in over predicting NOx concentrations during commute periods. No effects to NOx or ozone were seen during daylight hours when vertical mixing far exceeded the 300 m minimum. Between 8 PM and 6 AM, however, the deeper mixing depths were effective at reducing NOx concentrations in the central LVV substantially, but those reduction had no impact on morning or daytime NO_2 or ozone production. By 6-7 AM, NOx and ozone concentrations were identical to the base case, indicating a very rapid growth of deep mixing above 300 m early each day. Therefore, this Kv modification was not carried into additional CAMx simulations.

8.4.10 Sensitivity to Biogenic Emissions

8.4.10.1 BEIS3.6/BELD4 on the 12US2 Grid

SENS4 replaced BEIS3.7/BELD5 biogenic emissions on the 12US2 domain with BEIS3.6/BELD4 biogenic emissions from the 2016v1 MP. Only the 12US2 domain was run for this test, without the CC4c2 grid, as BEIS3.6/BELD4 biogenic emissions were readily available on that grid. Otherwise SENS4 was configured the same as the base case.

Table 8-7a lists monthly NMB and NME statistical performance for MDA8 ozone over all days and all ozone monitoring sites within the CC4c2 domain. The table compares results from the SENS4 and EPA's 2016v2 12US2 simulation to maximize consistency for the evaluation. NMB and NME are color coded for visual reference to statistical goals and criteria benchmarks. Performance results in SENS4 were remarkably improved over the EPA simulation, despite the continuing large negative bias outside of the criteria benchmark in May. Bias and gross error were within or very near the goals in June through August, with a slight over prediction in August. Overall statistical performance over the entire May through August period was also within goals.

Table 8-7a. Monthly model performance statistics for MDA8 ozone over all days and all ozone monitoring sites within the CC4c2 domain that operated during the summer of 2016. Normalized mean bias (NMB) and normalized mean unsigned error (NME, also referred to as gross error) are shown with color coding indicating statistics outside performance criteria (red), between goals and criteria (yellow) and within goals (green). Results from the SENS4 case and EPA's 2016v2 12US2 simulation are compared.

Month	MDA8 Ozone (no cutoff)			
	NMB (%)		NME (%)	
	SENS4	EPA 12US2	SENS4	EPA 12US2
May	-14.4	-15.9	15.3	16.1
June	-2.6	-6.5	8.4	9.0
July	-2.2	-7.9	10.2	10.7
Aug	5.4	-0.6	12.6	11.5
May-Aug	-3.4	-7.7	11.6	11.8

Table 8-7b presents the same information but limited to sites and days when observed MDA8 ozone exceeded 60 ppb. Similar improvements were evident on high ozone days, with just slightly more negative bias.

Table 8-7b. As in Table 8-7a, but for all sites and days when monitored MDA8 ozone exceeded 60 ppb.

Month	MDA8 Ozone (60 ppb cutoff)			
	NMB (%)		NME (%)	
	SENS4	EPA 12US2	SENS4	EPA 12US2
May	-18.2	-19.7	18.2	19.7
June	-3.8	-9.2	8.5	9.6
July	-5.0	-12.0	11.1	12.6
Aug	0.4	-5.6	11.6	11.8
May-Aug	-5.6	-11.1	11.7	12.8

Figure 8-15 displays a spatial map of site-specific monthly NMB patterns for MDA8 ozone across the CC4c2 portion of the 12US2 domain. In this case, NMB was determined from all days without the 60 ppb cutoff applied, so the maps are consistent with the data in Table 8-7a. These plots again show dramatic improvements in bias in June and July relative to the base case (Figure 4), and the change to slight over predictions throughout much of the LVV in August.

Figure 8-16 presents a similar spatial map of site-specific monthly NMB, but for selected monitoring sites across the Mojave Desert of Southern California. The plots indicate some improvement in overall negative bias patterns relative to the base case (Figure 8-3), but the differences are more subtle than for sites within the LVV. Therefore, the regional under prediction bias over the California transport corridor remained an issue.

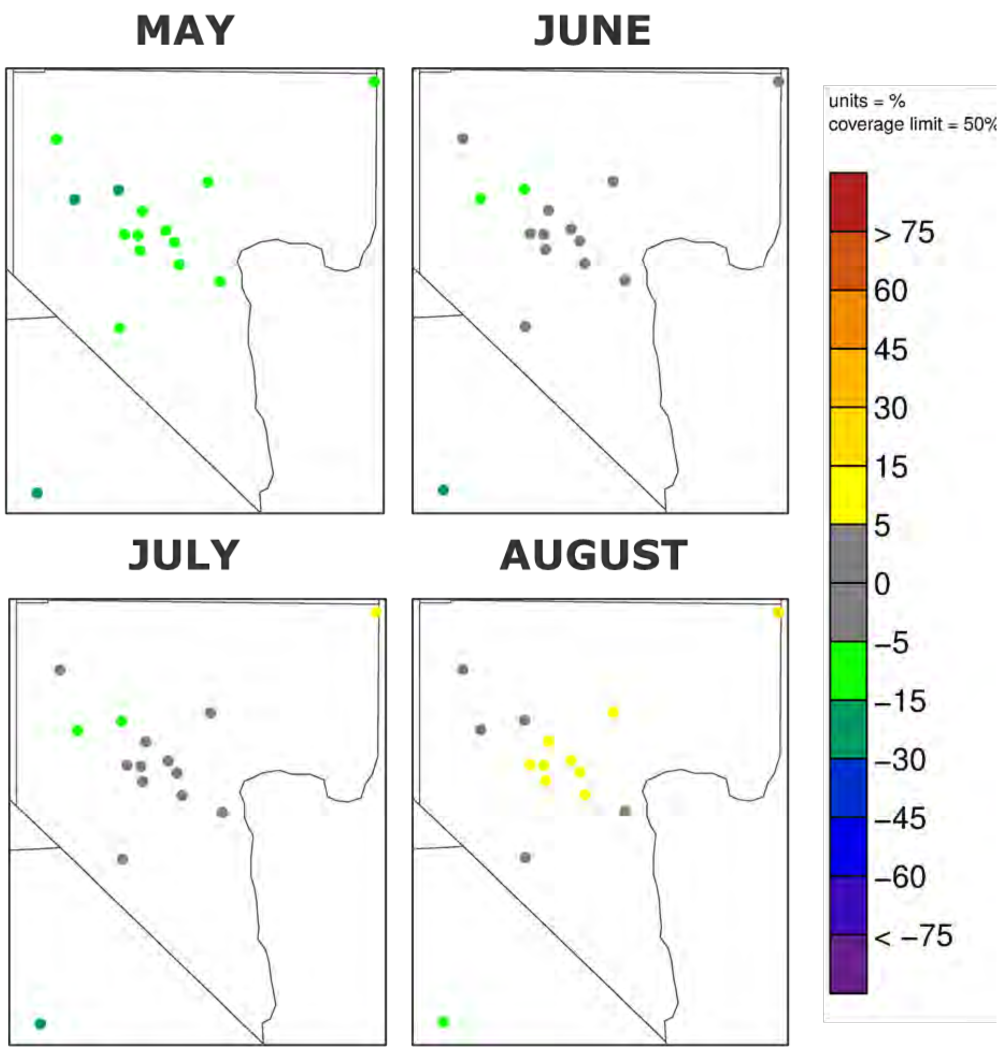


Figure 8-15. Map of site-specific monthly normalized mean bias (NMB) patterns for MDA8 ozone from SENS4 within the CC4c2 portion of the 12US2 domain.

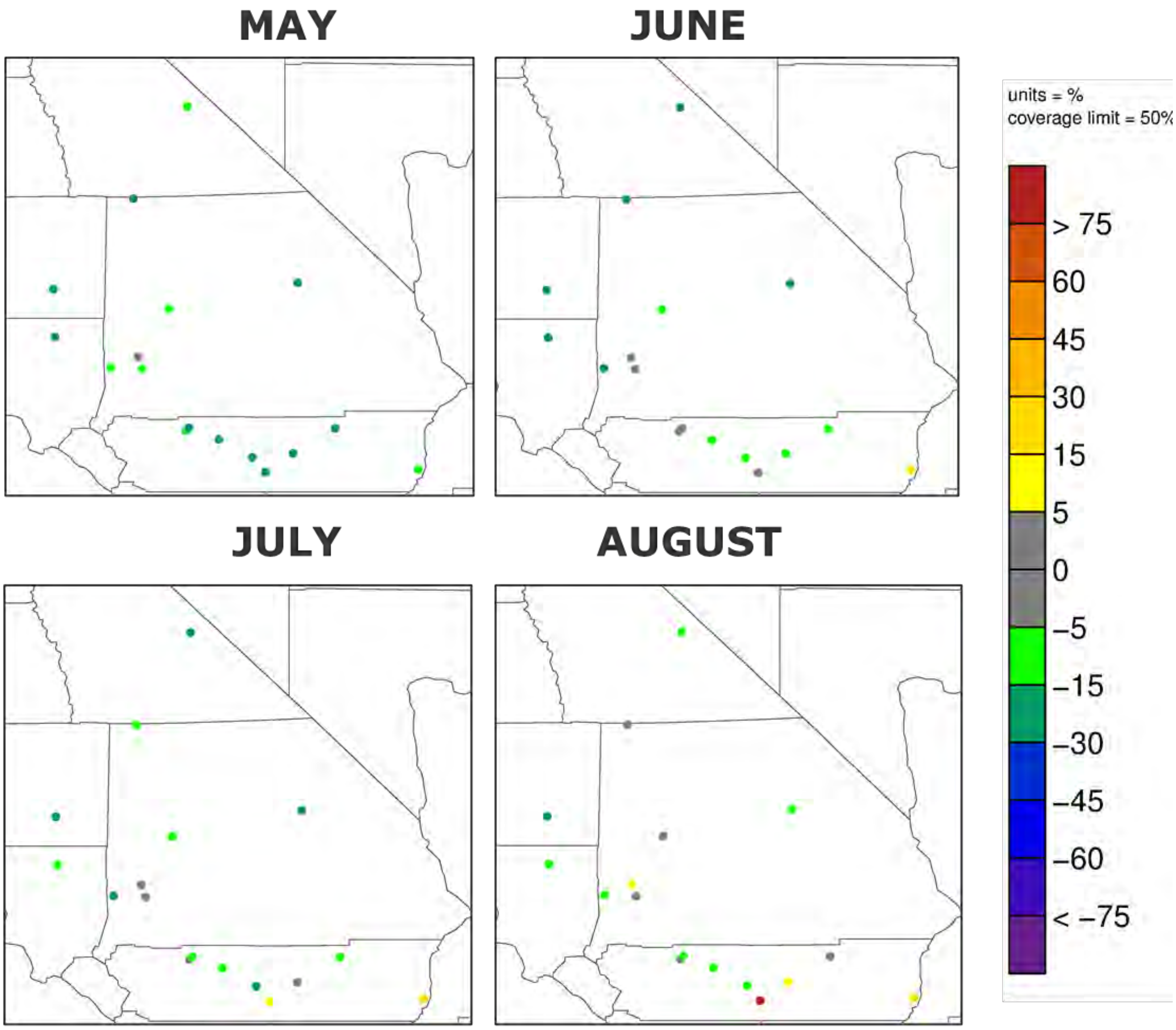


Figure 8-16. Map of site-specific monthly normalized mean bias (NMB) patterns for MDA8 ozone from SENS4 across the Mojave Desert of the southern California portion of the 12US2 domain.

Figure 8-17 presents time series of observed and simulated MDA8 ozone during the May through August modeling period at two representative monitoring sites. The use of BEIS3.6/BELD4 biogenic emissions in SENS4 led to a substantial increase in simulated ozone at these two sites, as well as all other LVV sites as shown above. There was a clear tendency to over predict daily ozone in August, but the SENS4 simulation in June and July was markedly better than EPA's 2016v2 results, and by extension better than the initial base case simulation on the CC4c2 grid.

These results showed improved model performance when choosing the alternative source of biogenic emissions. BEIS3.6/BELD4 generated higher rural biogenic isoprene emissions but lower urban biogenic emissions relative to BEIS3.7. In this sensitivity run, lower urban biogenic emissions resulted in isoprene concentrations of roughly 0.25 ppb compared to more than 1 ppb in the base case. Therefore, isoprene from BEIS3.6 better agreed with 2021 field measurements in central Las Vegas (NOAA, 2022).

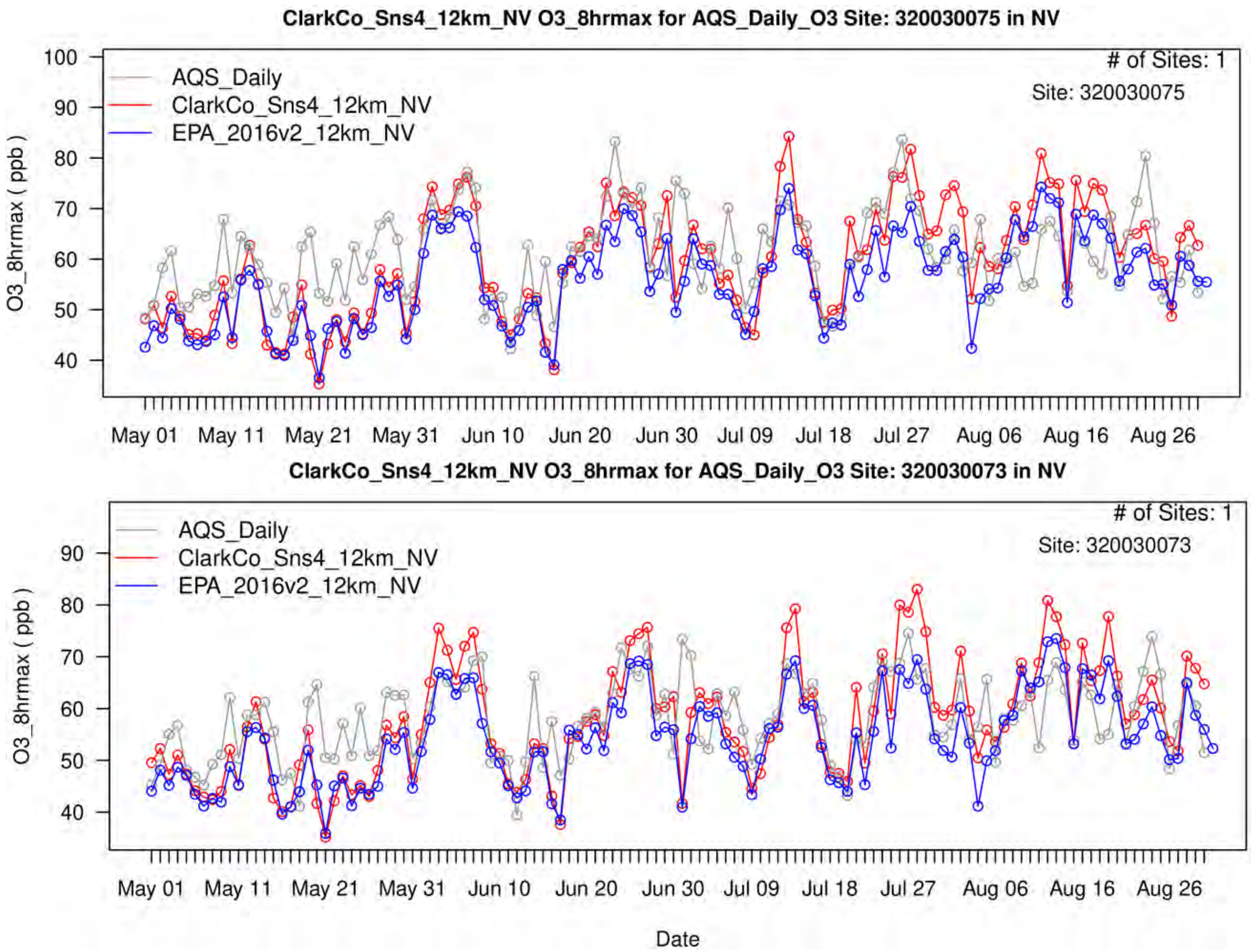


Figure 8-17. Time series of MDA8 ozone over the entire modeling period at the Joe Neal (top) and Palo Verde (bottom) monitoring sites. Daily AQS measurements are shown in grey, the modeled SENS4 results are shown in red, and EPA's results taken from their 2016v2 simulation on the 12US2 domain are shown in blue.

Higher levels of rural biogenics entering the basin generated more ozone in the NOx-rich conditions. The use of 12-km resolution may have played some role in increasing ozone production rates in the LVV as rural biogenics and urban NOx more readily mixed at this coarse resolution. Given the much higher rural VOC emissions, use of course resolution, and some large MDA8 ozone over predictions during June-August, we were concerned that the much higher ozone resulting from BEIS3.6/BELD4 led to a model that performed better but for the wrong reason.

In the Mojave Desert, however, much less ozone sensitivity to biogenic emissions was evident perhaps because of the NOx-lean (i.e., NOx-limited) conditions there. Biogenic isoprene also can react with and destroy ozone, resulting in lower ozone production rates in rural areas.

8.4.10.2 BEIS4/BELD6 on the 12US2/CC4c2 Grids

Table 8-8 lists 2016 summer monthly average biogenic emissions on the CC4c2 grid as determined from four different biogenic emission platforms (note that for completeness the table includes BEIS3.6/BELD4 estimates on the CC4c2 grid that we generated after SENS4 was completed).

Table 8-8. 2016 summer monthly biogenic emissions (TPD) estimated for the CC4c2 modeling domain from four biogenic modeling systems.

Biogenic Model	May	June	July	August	Average
	NOx				
BEIS3.6/BELD4 (2016v1)	6	9	9	9	8
BEIS3.7/BELD5 (2016v2)	5	7	8	7	7
BEIS4/BELD6	5	7	8	7	7
MEGAN3.2	17	32	30	27	27
Biogenic Model	VOC				
BEIS3.6/BELD4 (2016v1)	850	1,936	2,128	1,737	1,663
BEIS3.7/BELD5 (2016v2)	288	654	717	586	561
BEIS4/BELD6	71	154	167	139	133
MEGAN3.2	2	3	15	26	12
Biogenic Model	Isoprene				
BEIS3.6/BELD4 (2016v1)	145	294	304	258	250
BEIS3.7/BELD5 (2016v2)	57	114	118	101	97
BEIS4/BELD6	13	23	22	20	19
MEGAN3.2	1	1	7	2	3
Biogenic Model	Terpene				
BEIS3.6/BELD4 (2016v1)	253	582	653	534	505
BEIS3.7/BELD5 (2016v2)	64	148	165	135	128
BEIS4/BELD6	16	36	40	33	31
MEGAN3.2	1	1	4	2	2

Figures 8-18a and b show plots of season-average NOx and VOC emissions, respectively, for each of the four models. While modeled NOx and VOC emission rates trended downward with succeeding biogenic emission models, the huge range of emission rates among these versions is stunning and illustrates the remaining uncertainty in desert biogenic emission estimates and related vegetative characterization over just the last few years. Most notably, VOC emissions vary by nearly 1000-fold between BEIS3.6 and the latest Model of Emissions of Gases and Aerosols from Nature (MEGAN), version 3.2 (UCI, 2022).

The rather large VOC estimates from BEIS3.6/BELD4 confirmed our suspicion of that model's tendency to over predict regional VOC emissions and resulting ozone production in the LVV, despite the lower urban isoprene levels in the LVV in agreement with 2021 measurements. BEIS3.7/BELD5, on the other hand, was a complete inversion of isoprene emission patterns from its predecessor, with much smaller rural rates but larger urban rates that led to isoprene overestimates in the LVV yet much lower ozone. The latest version, BEIS4/BELD6, reduced both rural and urban isoprene emissions below both of its predecessors. Sensitivity results from using this version are described below. MEGAN3.2 indicated practically zero biogenic VOC within the CC4c2 domain, which appeared to be far too low relative to evidence from 2021 LVV measurements. However, MEGAN estimated the largest amount of biogenic NOx emissions among all four models by factors of 3 to 4. Given its very different and very low VOC emission profiles, we dropped MEGAN3.2 from further consideration.

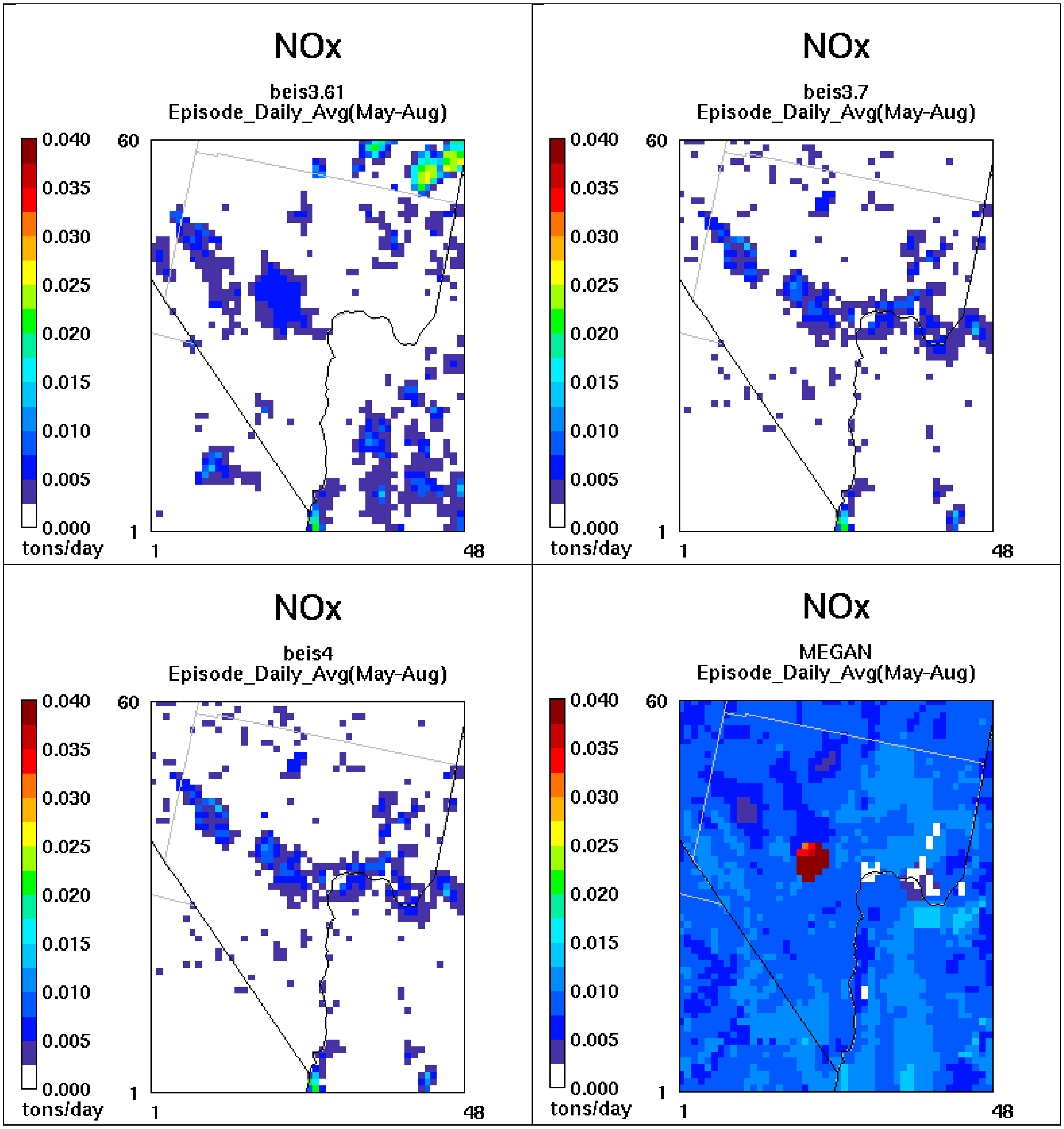


Figure 8-18a. Spatial plots of season-average NOx emissions (tons per day) from four biogenic models: BEIS3.6/BELD4 (top left); BEIS3.7/BELD5 (top right); BEIS4/BELD6 (bottom left); MEGAN3.2 (bottom right).

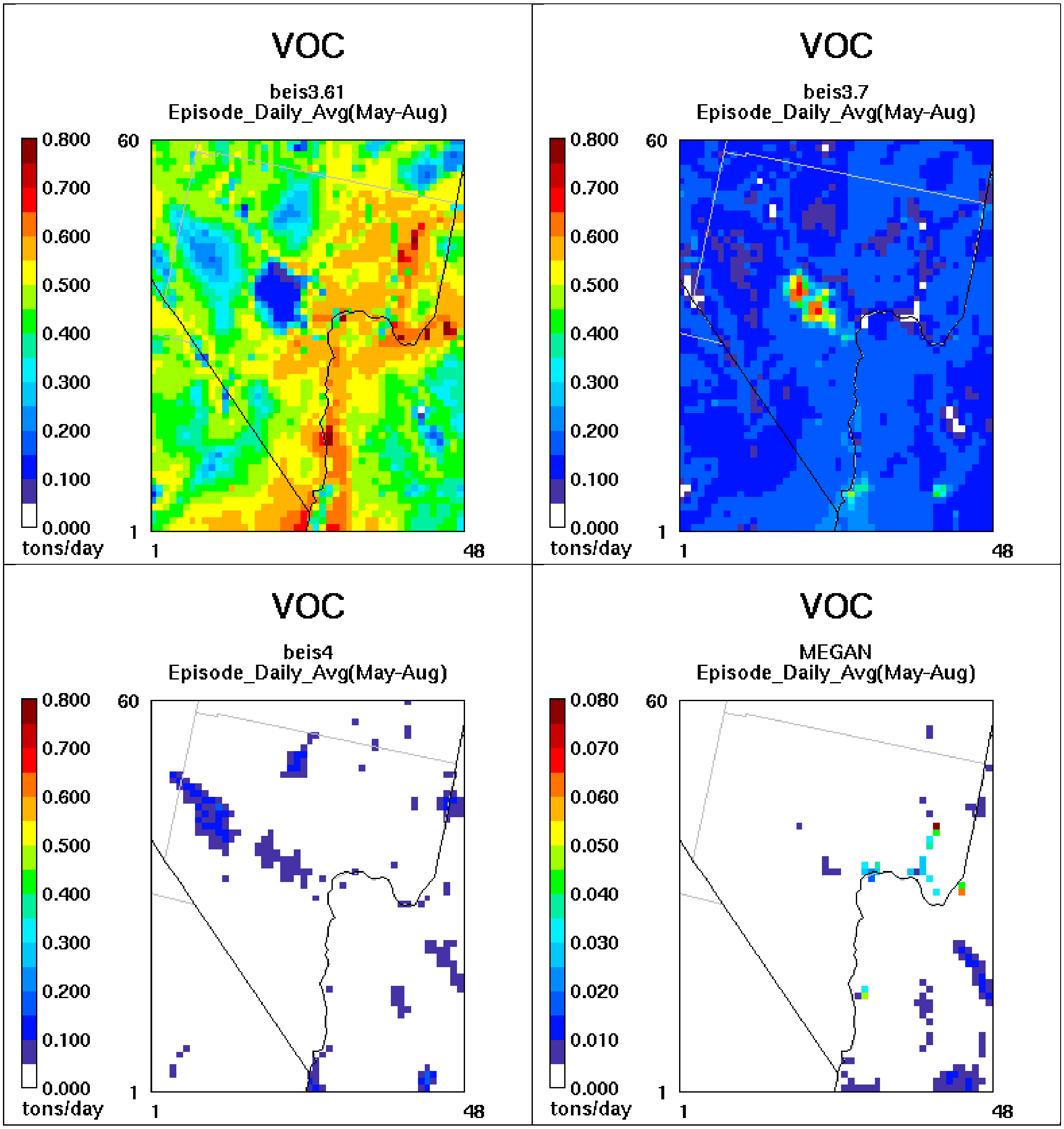


Figure 8-18b. Spatial plots of season-average VOC emissions (tons per day) from four biogenic models: BEIS3.6/BELD4 (top left); BEIS3.7/BELD5 (top right); BEIS4/BELD6 (bottom left); MEGAN3.2 (bottom right). Note that the scale for MEGAN3.2 is ten times smaller than for all BEIS versions.

SENS5 replaced BEIS3.7/BELD5 biogenic emissions on the 12US2 and CC4c2 domains with estimates from the new BEIS4/BELD6 biogenic emissions model. The 12US2/CC4c2 domains were rerun with the model configuration from SENS1. Table 8-9a lists monthly NMB and NME statistical performance for MDA8 ozone over all days and all ozone monitoring sites within the CC4c2 domain. The table compares results from the SENS1 and SENS5 simulations. NMB and NME are color coded for visual reference to statistical goals and criteria benchmarks. Performance results in SENS5 were very similar to SENS1 indicating little sensitivity in using BEIS4 over BEIS3.7. Table 8-9b presents the same information but limited to sites and days when observed MDA8 ozone exceeded 60 ppb. Similar results were also evident on high ozone days, with just slightly more negative bias.

Table 8-9a. Monthly model performance statistics for MDA8 ozone over all days and all ozone monitoring sites within the CC4c2 domain that operated during the summer of 2016. Normalized mean bias (NMB) and normalized mean unsigned error (NME, also referred to as gross error) are shown with color coding indicating statistics outside performance criteria (red), between goals and criteria (yellow) and within goals (green). Results from the SENS1 and SENS5 cases are compared.

Month	MDA8 Ozone (no cutoff)			
	NMB (%)		NME (%)	
	SENS1	SENS5	SENS1	SENS5
May	-19.5	-19.2	19.6	19.3
June	-9.4	-9.9	11.2	11.6
July	-8.6	-7.9	11.2	11.0
Aug	-1.2	-1.3	10.9	10.3
May-Aug	-9.7	-9.5	13.2	13.0

Table 8-9b. As in Table 8-9a, but for all sites and days when monitored MDA8 ozone exceeded 60 ppb.

Month	MDA8 Ozone (60 ppb cutoff)			
	NMB (%)		NME (%)	
	SENS1	SENS5	SENS1	SENS5
May	-22.5	-22.5	22.5	22.5
June	-11.4	-12.8	12.7	13.3
July	-12.0	-11.8	12.8	12.6
Aug	-5.3	-6.4	12.0	10.8
May-Aug	-12.1	-12.7	14.2	14.1

Figure 8-19 presents spatial maps of site-specific monthly NMB for selected monitoring sites across the Mojave Desert of Southern California. The plots indicate very similar performance relative to SENS1 (Figure 8-8). Therefore, the regional under prediction bias over the California transport corridor remained an issue.

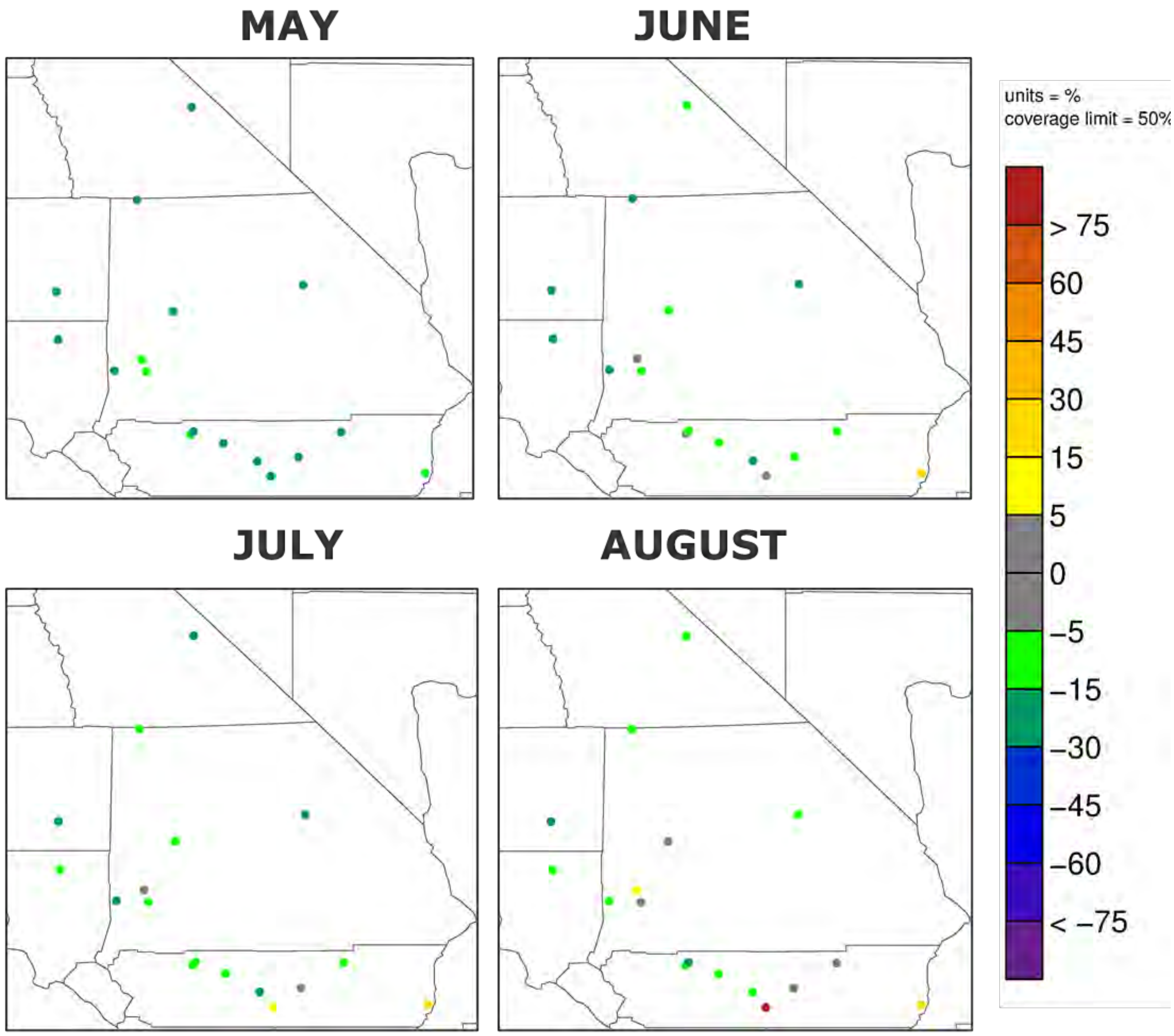


Figure 8-19. Map of site-specific monthly normalized mean bias (NMB) patterns for MDA8 ozone from SENS5 across the Mojave Desert of the southern California portion of the 12US2 domain.

Figure 8-20 presents time series of observed and simulated MDA8 ozone during the May through August modeling period at two representative monitoring sites. The use of BEIS4/BELD6 biogenic emissions in SENS5 resulted in very similar results as SENS1, yet slightly degraded ozone model performance toward a larger under prediction tendency. BEIS4/BELD6 generated much lower rural and urban biogenic isoprene emissions. In this sensitivity run, lower urban biogenic emissions resulted in isoprene concentrations of roughly 0.01 ppb, which is about 10-20 times lower than 2021 field measurements in central Las Vegas (NOAA, 2022).

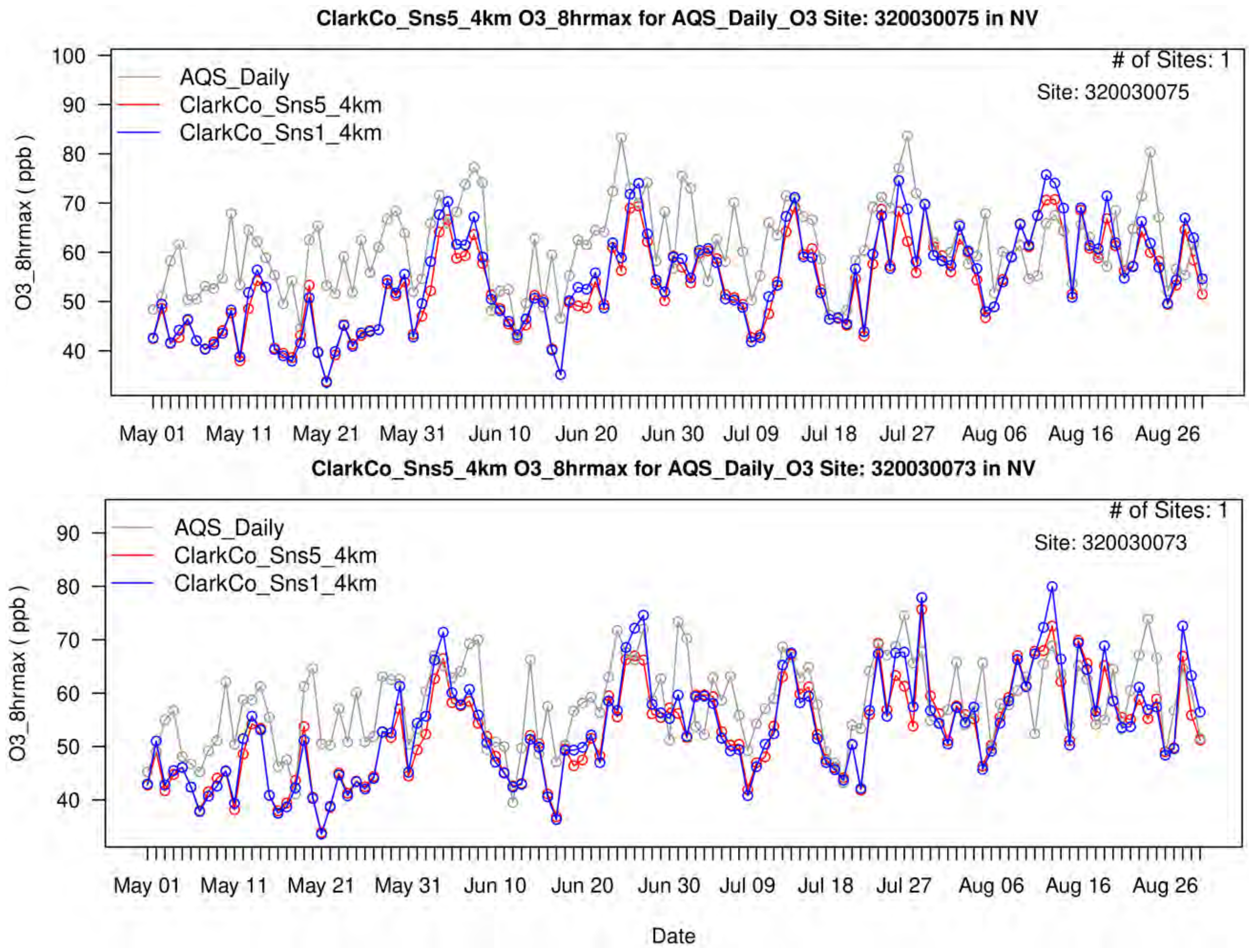


Figure 8-20. Time series of MDA8 ozone over the entire modeling period at the Joe Neal (top) and Palo Verde (bottom) monitoring sites. Daily AQS measurements are shown in grey, the modeled SENS5 results are shown in red, and SENS1 results are shown in blue.

8.4.11 Sensitivity to CAM-Chem Boundary Conditions

8.4.11.1 Global Model Intercomparison

Prior to conducting the second sensitivity test involving the source of continental boundary conditions, we graphically compared simulated ozone fields from two global models, GEOS-Chem and CAM-Chem, at several altitudes. We also compared model results to routine vertical ozone profile data recorded by NOAA ozonesondes launched from Trinidad Head, California. The purpose of this comparison was to identify any consistent biases among the two global models, and to assess whether a single model consistently best characterized mid- and upper-tropospheric ozone patterns and thus has the best chance to positively impact regional surface ozone across the western US.

Figure 8-21 compares GEOS-Chem and CAM-Chem ozone fields, extracted to the CAMx 36US3 modeling grid, at several altitudes on May 1, 2016 at 00 UTC (4 PM Pacific Standard Time). Figure 8-22 shows similar comparisons on May 20, 2016 when high ozone was measured at the mountaintop monitor at Spring Mountain Youth Camp northwest of the LVV. In both cases, and throughout the modeling period, CAM-Chem consistently simulated higher ozone in mid-tropospheric tendrils by as much as 20-50 ppb.

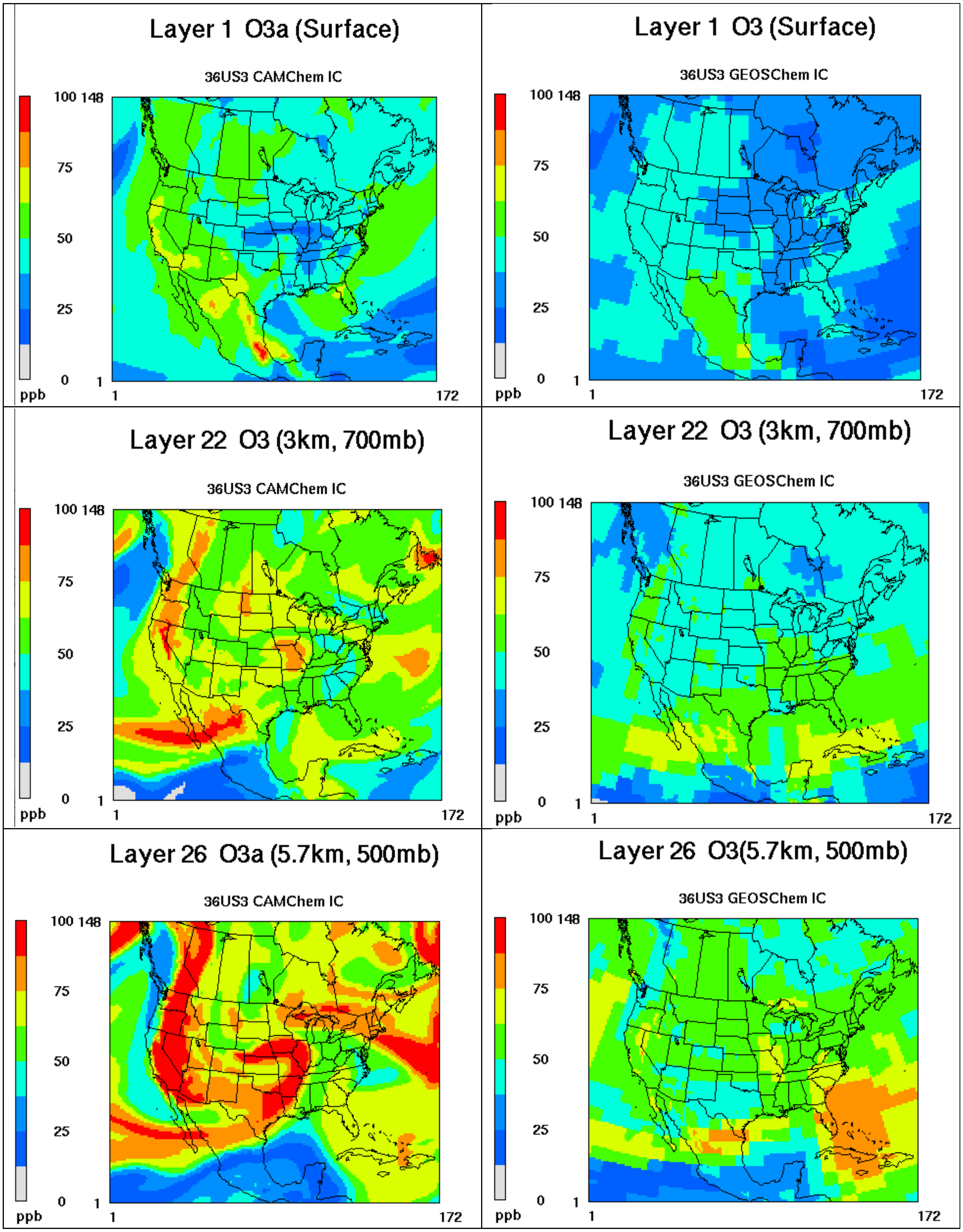


Figure 8-21. CAM-Chem (left) and GEOS-Chem (right) ozone fields extracted to the CAMx 36US3 modeling grid at three altitudes on May 1, 2016, 00 UTC (4 PM PST).

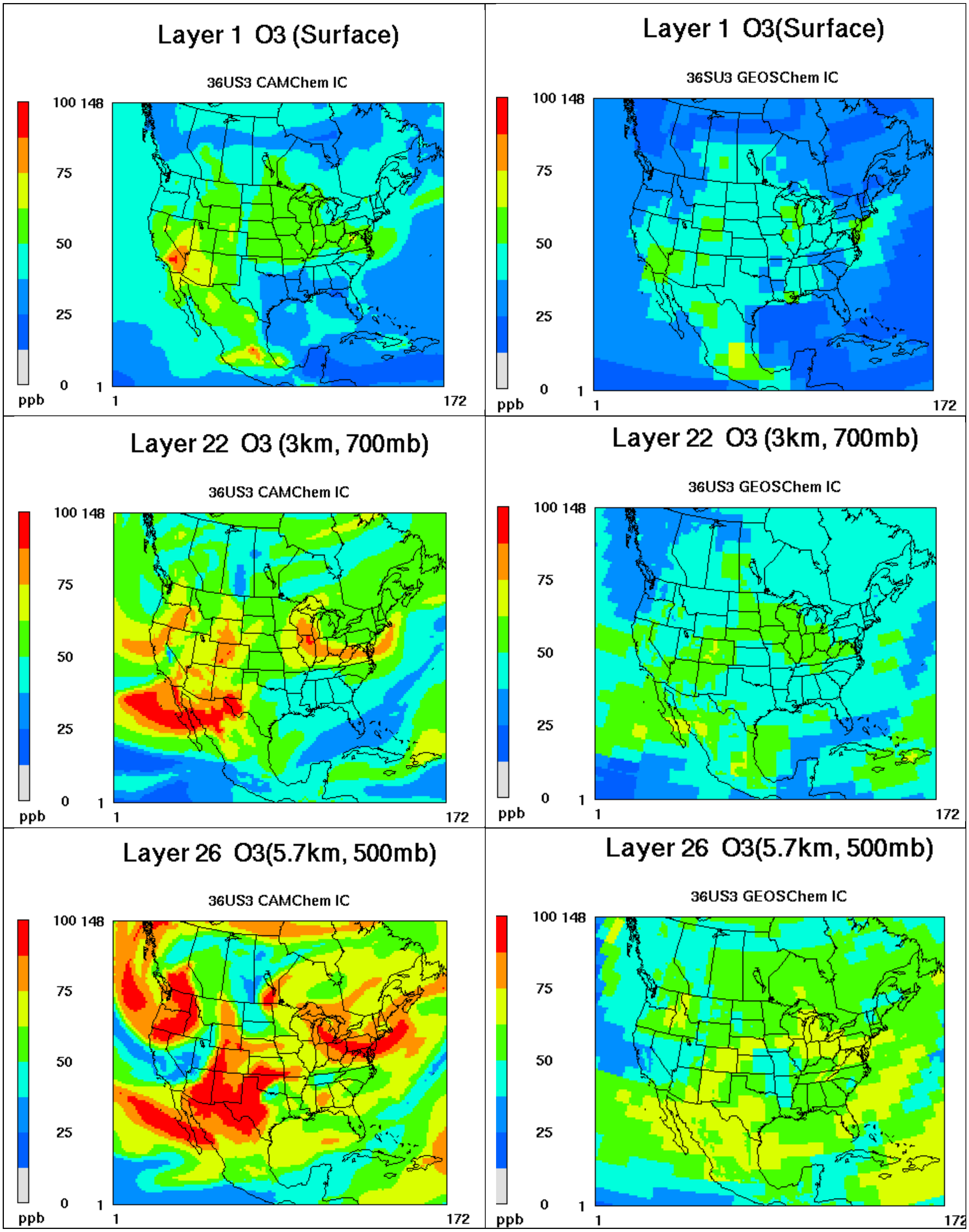


Figure 8-22. CAM-Chem (left) and GEOS-Chem (right) ozone fields extracted to the CAMx 36US3 modeling grid at three altitudes on May 20, 2016, 00 UTC (4 PM PST).

The value of ~75 ppb at 3 km over southern Nevada on May 20 agrees well with the 79 ppb measured at Spring Mountain Youth Camp on that date.

Figure 8-23 presents graphical comparisons of summer-season average ozone profiles observed at Trinidad Head, California and simulated by CAM-Chem and GEOS-Chem. Figure 8-24 compares profiles for each day when observations were recorded during the modeling period. Results confirm that the higher mid- and upper-tropospheric ozone concentrations simulated by CAM-Chem consistently tended to replicate observed profiles much better than GEOS-Chem. However, CAM-Chem suffered from a consistent low bias in the tropopause height and this led to large over estimates of stratospheric ozone relative to GEOS-Chem, which performed much better in that respect.

The higher mid-tropospheric ozone generated by CAM-Chem was nevertheless an intriguing feature that conceivably would lead to higher surface ozone across the western US mountains and deserts during deep afternoon mixing. Therefore, we chose to run CAMx with 36US3 BCs extracted from the 6-hourly CAM-Chem output fields. For this sensitivity case, we scaled back the CAM-Chem ozone results above 9 km (layers 30-35) by a uniform season-averaged factor of 0.56 to better replicate the stratospheric ozone profile. Resulting ozone profiles are shown in Figures 8-25 and 8-26 and confirm improved agreement.

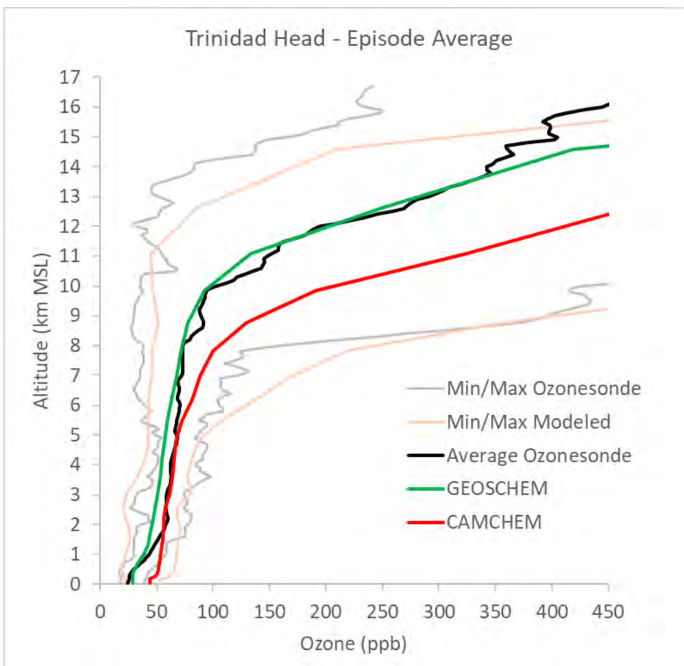


Figure 8-23. 2016 summer season-average ozone profiles observed at the NOAA Trinidad Head ozonesonde launch site (black) and simulated by GEOS-Chem (green) and CAM-Chem (red). Season-maximum and minimum observed profiles (grey) and simulated profiles among both models (orange) are also plotted.

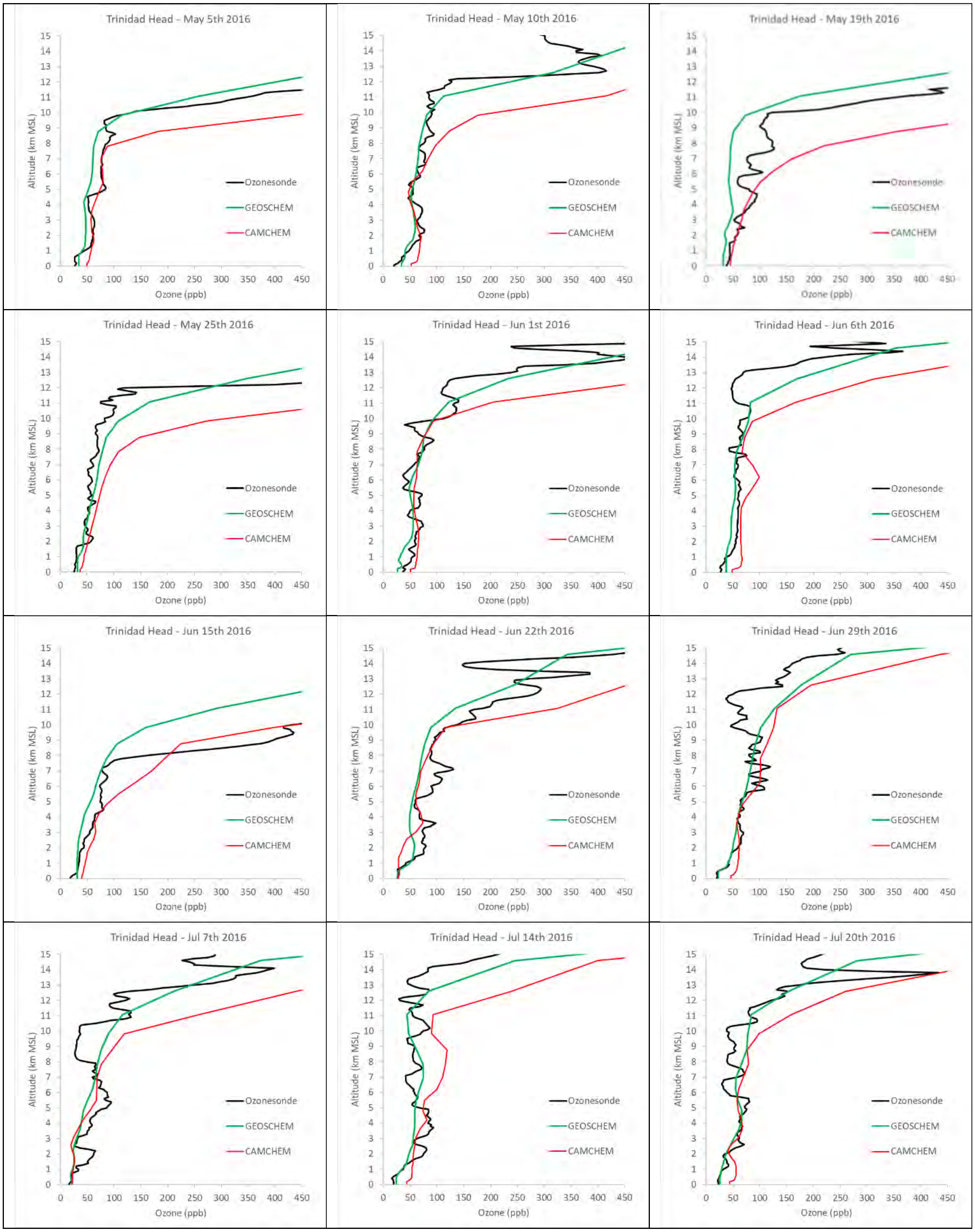


Figure 8-24. Ozone profiles during summer 2016 observed at the NOAA Trinidad Head ozonesonde launch site (black) and simulated by GEOS-Chem (green) and CAM-Chem (red).

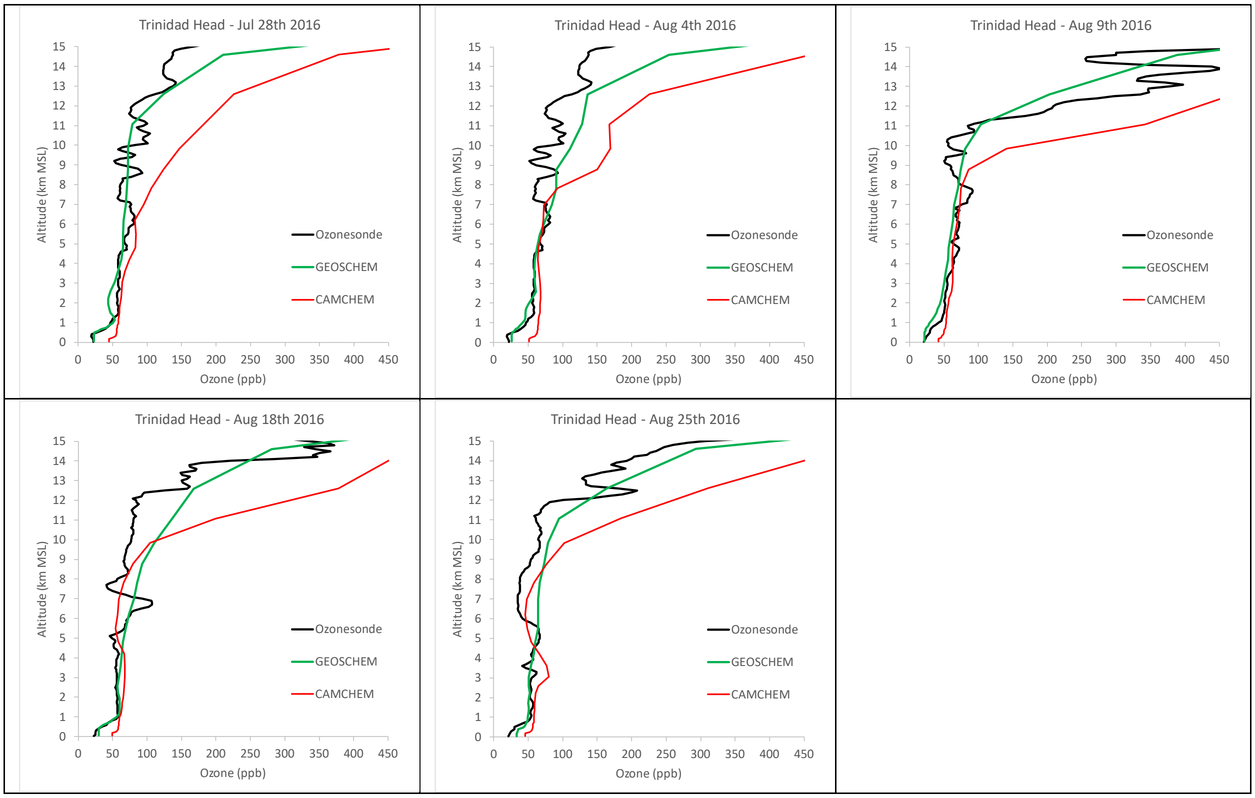


Figure 8-24 (concluded).

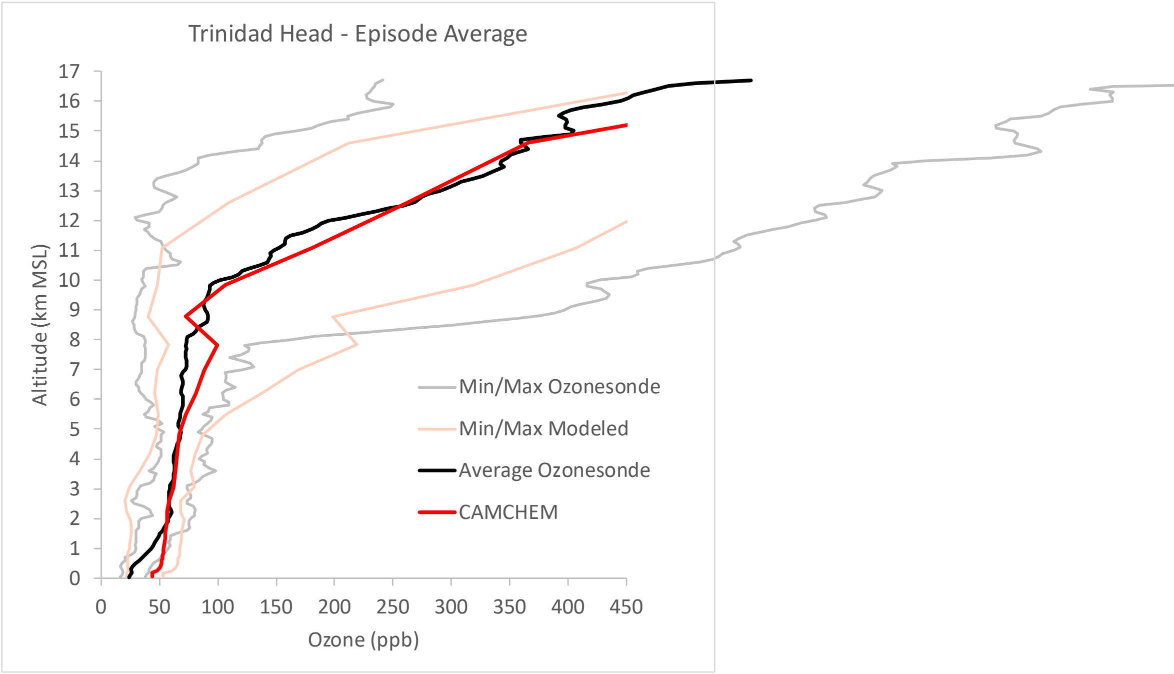


Figure 8-25. 2016 summer season-average ozone profiles observed at the NOAA Trinidad Head ozonesonde launch site (black) and simulated by CAM-Chem where ozone above 9 km was scaled by 0.56 (red). Season-maximum and minimum observed profiles (grey) and CAM-Chem simulated profiles with scaling (orange) are also plotted.

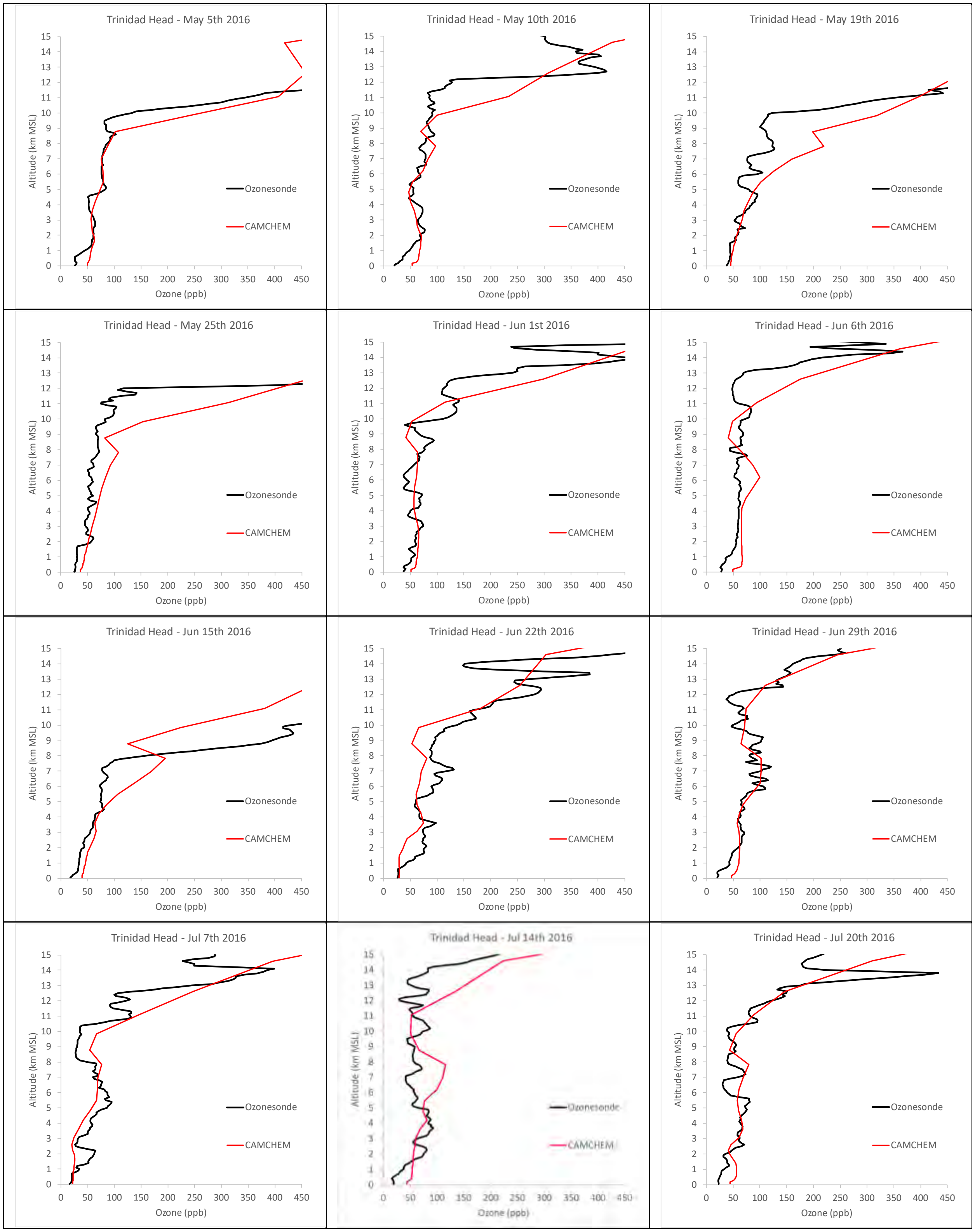


Figure 8-26. Ozone profiles during summer 2016 observed at the NOAA Trinidad Head ozonesonde launch site (black) and simulated by CAM-Chem where ozone above 9 km was scaled by 0.56 (red).

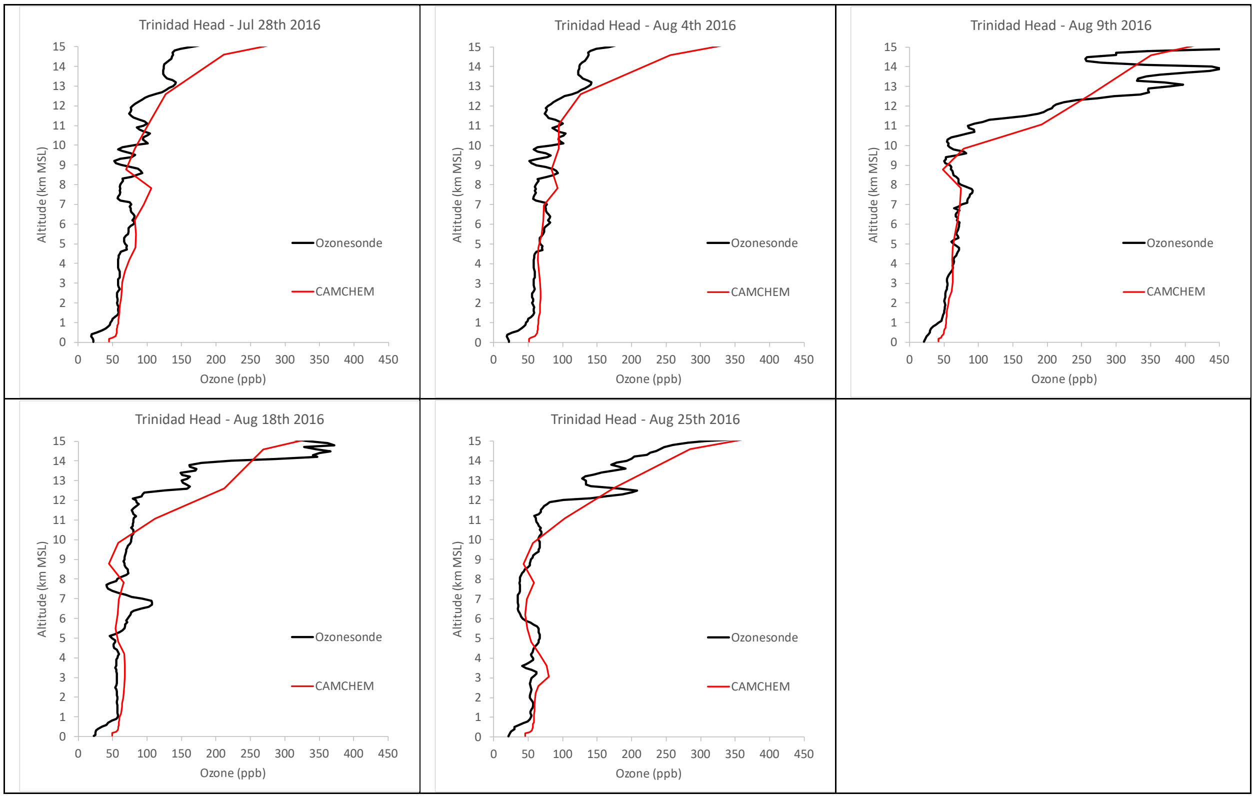


Figure 8-26 (concluded).

8.4.11.2 CAM-Chem Sensitivity Results

SENS6 used CAM-Chem to define lateral BCs on the 36US3 grid, and resulting three-dimensional output fields were downscaled to provide BCs for the 12US2/CC4c2 grids. Otherwise, CAMx was run with same configuration as SENS5 (BEIS4/BELD6) and SENS1 (elevated airport emissions, includes aerosols).

Table 8-10a lists monthly NMB and NME statistical performance for MDA8 ozone over all days and all ozone monitoring sites within the CC4c2 domain. The table compares results from the SENS5 and SENS6 simulations. NMB and NME are color coded for visual reference to statistical goals and criteria benchmarks. Performance results in SENS6 were significantly improved during May-June, but statistical performance during July-August was similar to SENS5, indicating progressively less influence from North American background as represented by CAM-Chem as the summer progressed. Table 8-10b presents the same information but limited to sites and days when observed MDA8 ozone exceeded 60 ppb. Similar results were also evident on high ozone days, with just slightly more negative bias.

Figure 8-27 presents spatial maps of site-specific monthly NMB for selected monitoring sites across the Mojave Desert of Southern California. The plots indicate improvements in NMB for several sites during May-June yet similar results as SENS5 during July-August (Figure 8-19). Therefore, the regional under prediction bias over the California transport corridor was improved substantially during the months when they were largest.

Table 8-10a. Monthly model performance statistics for MDA8 ozone over all days and all ozone monitoring sites within the CC4c2 domain that operated during the summer of 2016. Normalized mean bias (NMB) and normalized mean unsigned error (NME, also referred to as gross error) are shown with color coding indicating statistics outside performance criteria (red), between goals and criteria (yellow) and within goals (green). Results from the SENS5 and SENS6 cases are compared.

Month	MDA8 Ozone (no cutoff)			
	NMB (%)		NME (%)	
	SENS5	SENS6	SENS5	SENS6
May	-19.2	-5.0	19.3	8.5
June	-9.9	-4.8	11.6	9.9
July	-7.9	-7.1	11.0	10.5
Aug	-1.3	-1.7	10.3	10.5
May-Aug	-9.5	-4.7	13.0	9.9

Table 8-10b. As in Table 8-10a, but for all sites and days when monitored MDA8 ozone exceeded 60 ppb.

Month	MDA8 Ozone (60 ppb cutoff)			
	NMB (%)		NME (%)	
	SENS5	SENS6	SENS5	SENS6
May	-22.5	-11.2	22.5	11.4
June	-12.8	-9.4	13.3	10.9
July	-11.8	-11.7	12.6	12.7
Aug	-6.4	-8.8	10.8	10.6
May-Aug	-12.7	-10.3	14.1	11.5

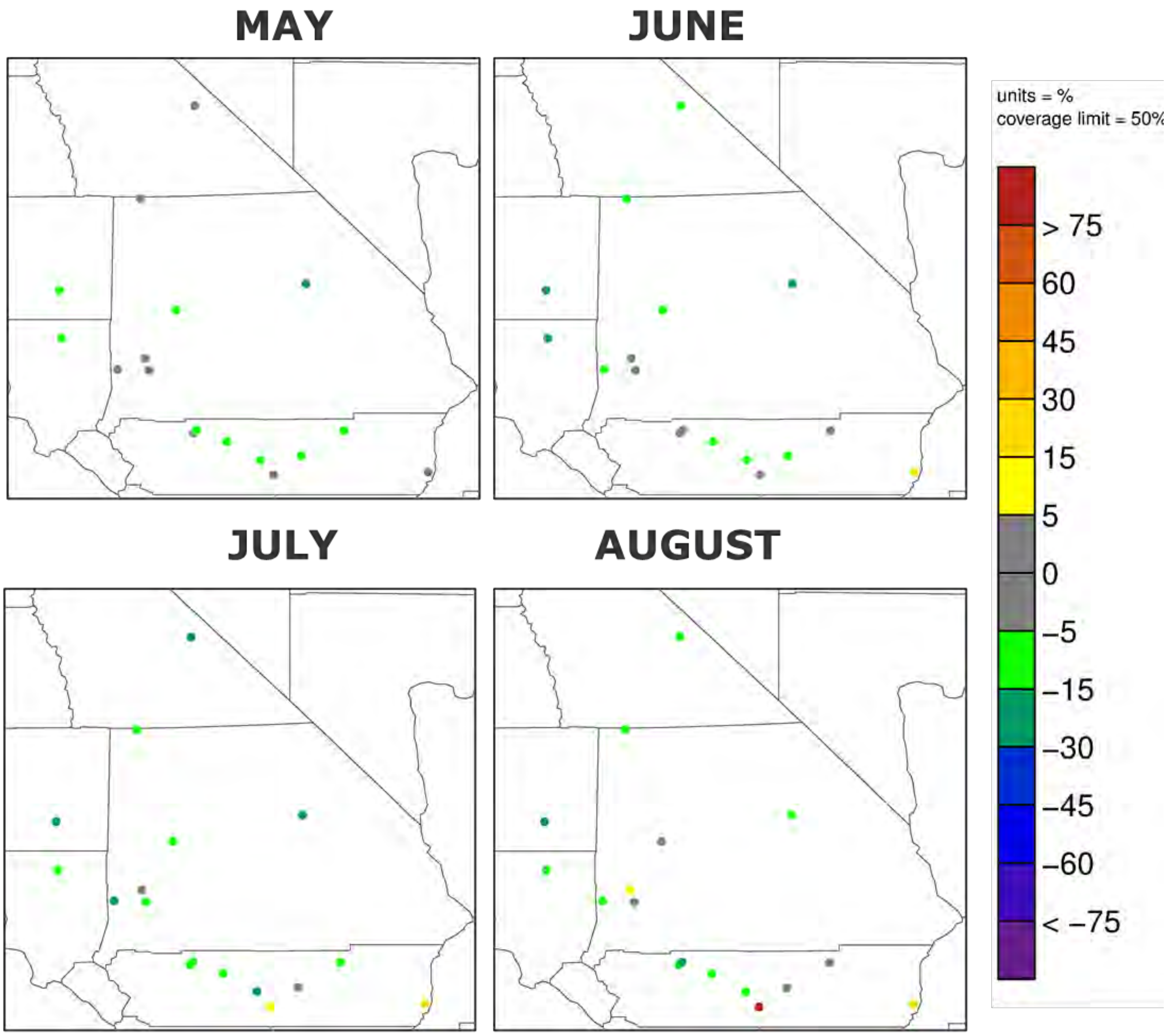


Figure 8-27. Map of site-specific monthly normalized mean bias (NMB) patterns for MDA8 ozone from SENS6 across the Mojave Desert of the southern California portion of the 12US2 domain.

Figure 8-28 presents time series of observed and simulated MDA8 ozone during the May through August modeling period at two representative monitoring sites. The ozone improvements during May-June from the use of CAM-Chem boundary conditions are clear. During July-August, however, the model settled into the same patterns that were seen from SENS1 and SENS5, with perhaps a small incremental deterioration in the under prediction bias.

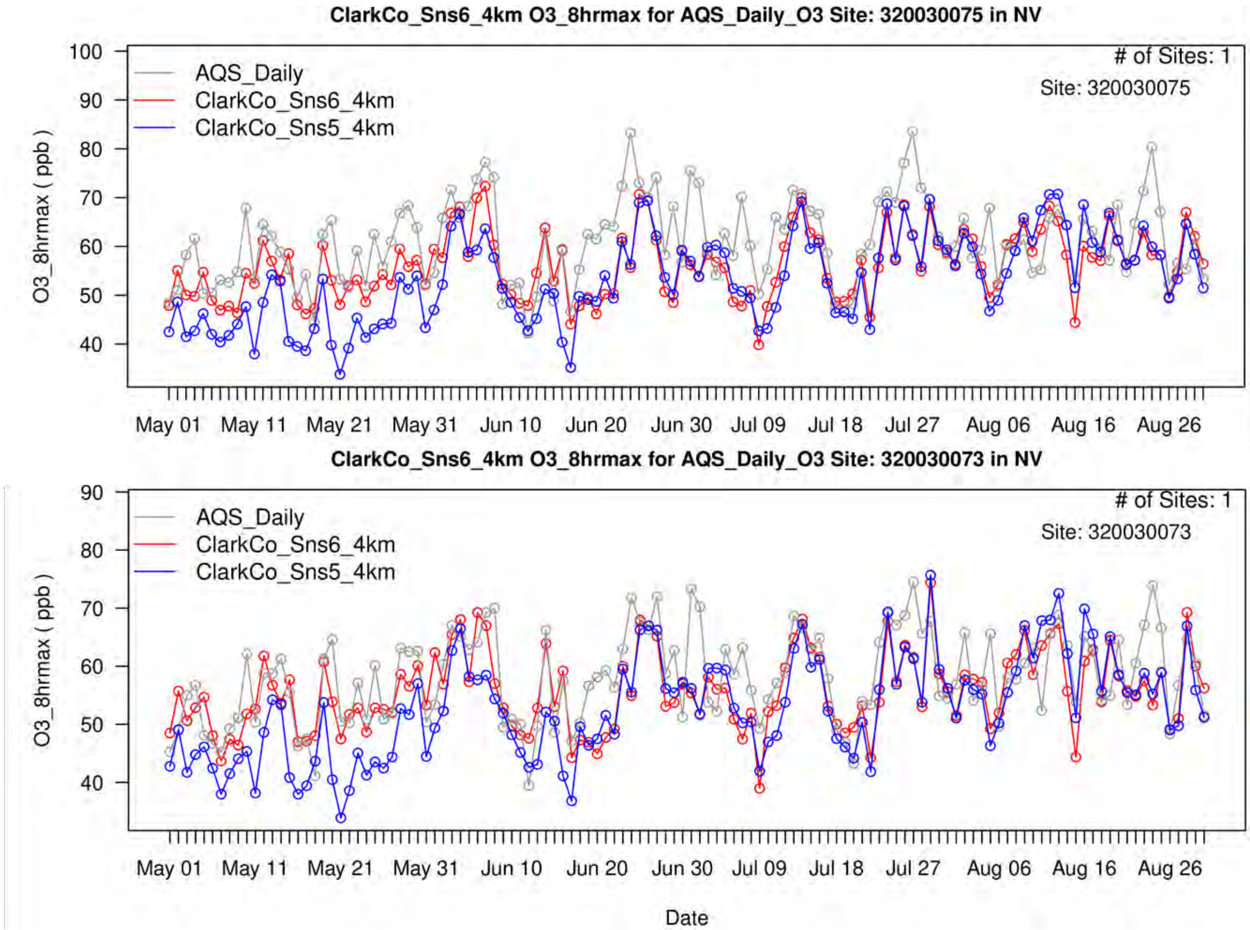


Figure 8-28. Time series of MDA8 ozone over the entire modeling period at the Joe Neal (top) and Palo Verde (bottom) monitoring sites. Daily AQS measurements are shown in grey, the modeled SENS6 results are shown in red, and SENS5 results are shown in blue.

8.5 Final Base Case Configuration and Results

Based on results from the initial CAMx 2016 base case simulation, model performance was insufficient to support regulatory analyses for the CCNAA SIP. However, from 6 sets of sensitivity tests we identified specific updates that improved model results and we incorporated these into the final 2016 base case configuration:

- Apply elevated LTO emissions from Harry Reid International Airport to reduce the large NOx burden in central Las Vegas;
- Include aerosols and related chemistry so that the full effect from wildfires and large urban pollution plumes are properly characterized throughout the modeling domain, although this was shown to have little impact on ozone results;
- Apply biogenic emissions derived from the latest BEIS4/BELD6 model on the 36US3, 12US2 and CC4c2 grids to replace the original BEIS3.7/BELD5 biogenic emissions from the 2016v2 MP;
- Apply an alternative set of 36US3 initial/boundary conditions derived from NCAR's 2016 CAM-chem global chemistry model results.

This configuration was identical to SENS6, and so that sensitivity configuration was used as the final base case (Table 8-11). In this section we provide a more detailed analysis of SENS6 results and compare them to statistical results from the original base case to affirm the performance improvements. We then analyze the top 10 predicted MDA8 ozone days at each official DV monitor within the CCNAA, which were used in the 2023 DV projections, and note the number and type of observed high ozone days that were captured.

8.5.1 Summary

The final 2016 base case is referred to as "Base2" in plots and tables below. Results from the model performance evaluation are summarized below with comparisons back to the initial base case:

- Model performance in replicating observed MDA8 ozone patterns was significantly improved during May-June, while performance during July-August was similar to the initial base case.
- Model bias and error statistics for MDA8 ozone remained consistent across all sites in the final base case simulation, so there was no single site that influenced statistical results.
- Results indicated that the final base case performed typically well for ozone during May through June and continued to perform notably well during August.
  - The remaining systematic under prediction tendency continued to implicate a lack of regional ozone and associated transport into the LVV.
- Performance in replicating the highest peak ozone days was not especially skillful in any month, but the final base case reduced occasional over predictions on non-event dates in August.
  - All days when peak observed MDA8 ozone exceeded 70 ppb remained under predicted in the final base case by an average of 10 ppb, regardless of influences by local emissions or wildfires.
- The top 10 modeled days at each of 6 key (exceedance) monitoring sites within the CCNAA were all above 60 ppb.
  - All sites included a similar set of dates in different orders and matched up with 7 or 8 observed days that exceed 70 ppb with small bias within a few percent and gross error of typically 5%.
- Elevating Reid Airport emissions reduced the overall surface NO_2 over prediction bias but did not ameliorate it entirely at neighborhood monitors.
  - The impact to diurnal NO_2 concentrations was substantial during certain hours of the day especially at sites closest to Reid Airport during commute hours.
  - The NOx reduction in central Las Vegas raised simulated ozone there in better agreement with nearby ozone measurements, indicating a NOx disbenefit response.
- Ozone production from the dearth of biogenic emissions in the desert environment was likely minimal given very low isoprene concentrations measured during the 2021 field study.
  - The initial base case using BEIS3.7 clearly over predicted morning isoprene concentrations within the urban area at 1-2 ppb relative to 2021 measurements of a few tenths of a ppb.
  - BEIS4 resulted in large urban isoprene under predictions of around 0.01 ppb.
  - We conclude that there is far too much uncertainty in the biogenic models to know whether any of them appropriately estimate rural and urban VOC emissions in the desert environment of the southwestern US.

Table 8-11. CAMx model configuration for the CCNAA 2016 final base case simulation. Changes from the initial base case are noted in red.

Model Component	CCNAA Application	Comment
Model Code	CAMx v7.20 - May 2022	
Horizontal Grids		
Map Projection	Lambert Conic Conformal	EPA 2016 MP
36 km (36US3)	172 x 148 cells	EPA 2016 MP (1-way nesting)
12 km (12US2)	396 x 246 cells (no buffer cells)	EPA 2016 MP (2-way nesting)
4 km (CC4c2)	50 x 62 cells (with buffer cells)	CCNAA grid (2-way nesting)
Vertical Grid	35 layers	EPA 2016 MP, defined by WRF
Initial Conditions	36US3 IC April 1 from CAM-Chem, 12US2/CC4c2 IC May 1 from 36US3	
Boundary Conditions	36US3 BC from CAM-Chem, 12US2 BC from 36US3	
Time Zone	UTC	EPA 2016 MP
Emissions		
36/12 km Data Sources	EPA 2016v2 MP	
4 km Data Sources	EPA 2016v2 MP + Clark County Data, elevated Reid LTO emissions	
Models/Processing Tools	SMOKE, MOVES3, SMOKE-MOVES, BEIS4/BELD6	CCNAA grid
Plume-in-Grid	Off	No large point sources in high-resolution CCNAA grid
In-line Ix emissions	On	Oceanic halogens
Chemistry		
Gas Phase Chemistry	CB6r5	Latest mechanism available
Aerosol Chemistry	None	Gas phase only
Meteorological Interface	WRFCAMx v5.2	
Horizontal Diffusion	Smagorinsky	Spatially variant K-theory
Vertical Diffusion	YSU Kv formulation	Minimum Kv 0.1 to 1.0 m^2/s
ACM2	Off	Non-local boundary layer convection
Sub-grid Cloud Convection	Off	
Deposition		
Dry Deposition	Zhang03	
Wet Deposition	On	rain/snow/graupel
Surface Chemistry Model	Off	
Bi-directional Ammonia	Off	For aerosol chemistry
Numeric Solvers		
Gas Phase Solver	Euler Backward Iterative (EBI)	Default fast and accurate solver
Vertical Advection	Piecewise Parabolic Method (PPM)	Default
Horizontal Advection	Piecewise Parabolic Method (PPM)	Default
Integration Time Step	Wind speed dependent	~0.5-1 min (4 km), 1-5 min (12 km), 5-15 min (36 km)
Super Stepping	On	Maximizes time step selection

8.5.2 MDA8 Ozone Bias and Error Performance Statistics

Table 8-12a lists monthly NMB and NME statistical performance for MDA8 ozone over all days and all ozone monitoring sites within the CC4c2 domain. The table compares results from the Clark County initial and final base case simulation. NMB and NME are color coded for visual reference to statistical goals and criteria benchmarks. As seen in results from SENS6, statistical performance was significantly improved during May-June, while statistical performance during July-August was similar to the initial base case. Table 8-12b presents the same information but limited to sites and days when observed MDA8 ozone exceeded 60 ppb. Similar results were also evident on high ozone days, just with more negative bias in most months relative to Table 8-12a, but a noticeable increase in negative bias during August in the final base case.

Table 8-12a. Monthly model performance statistics for MDA8 ozone over all days and all ozone monitoring sites within the CC4c2 domain that operated during the summer of 2016. Normalized mean bias (NMB) and normalized mean unsigned error (NME, also referred to as gross error) are shown with color coding indicating statistics outside performance criteria (red), between goals and criteria (yellow) and within goals (green). Results from the Clark County initial and final base case simulations are compared.

Month	MDA8 Ozone (no cutoff)			
	NMB (%)		NME (%)	
	Base2	Base	Base2	Base
May	-5.0	-17.9	8.5	18.3
June	-4.8	-9.2	9.9	11.2
July	-7.1	-8.2	10.5	11.1
Aug	-1.7	0.1	10.5	10.7
May-Aug	-4.7	-8.8	9.9	12.8

Table 8-12b. As in Table 8-12a, but for all sites and days when monitored MDA8 ozone exceeded 60 ppb.

Month	MDA8 Ozone (60 ppb cutoff)			
	NMB (%)		NME (%)	
	Base2	Base	Base2	Base
May	-11.2	-21.5	11.4	21.5
June	-9.4	-11.3	10.9	12.7
July	-11.7	-11.7	12.7	12.7
Aug	-8.8	-4.3	10.6	11.4
May-Aug	-10.3	-11.5	11.5	13.9

Table 8-13 breaks out monthly NMB and NME over all days (i.e., no 60 ppb cutoff) at each monitoring site within the CC4c2 domain and compares results from the initial and base cases. Similar color shading is used to visually characterize values relative to goal and criteria benchmarks. Statistical results remained consistent across all sites in the final base case simulation, so there was no single site that influenced the statistics in Table 8-12a. The consistently worst performing site was in California, upstream of Clark County, which monitors air that often arrives directly from the Los Angeles basin. Again, dramatic improvements in bias and error are noted in May and June, with more similar results in July and August.

Table 8-13. Monthly model performance statistics for MDA8 ozone over all days at each monitoring site within the CC4c2 domain that operated during the summer of 2016. Normalized mean bias (NME) and normalized mean unsigned error (NME) are shown with color coding indicating statistics outside performance criteria (red), between goals and criteria (yellow) and within goals (green). Results from the Clark County initial and final base case simulations are compared.

	May				June				July				Aug			
	NMB		NME		NMB		NME		NMB		NME		NMB		NME	
Site Name	Base2	Base	Base2	Base	Base2	Base	Base2	Base	Base2	Base	Base2	Base	Base2	Base	Base2	Base
California	-13.2	-24.7	13.2	24.7	-13.2	-17.3	14.3	17.3	-14.6	-17.0	15.3	17.9	-11.0	-11.8	12.0	12.4
Apex	-5.9	-18.7	8.4	18.8	-4.4	-9.6	8.1	9.9	-7.5	-8.6	11.0	11.5	0.5	1.5	9.3	9.8
Mesquite	2.0	-12.3	7.6	13.4	3.2	-2.7	7.7	7.1	2.4	0.4	7.4	6.7	15.0	12.9	22.1	22.9
Paul Meyer	-6.2	-18.2	7.9	18.4	-6.7	-10.3	11.2	12.0	-8.5	-9.0	11.0	10.9	-4.7	-2.4	10.0	9.5
Walter Johnson	-6.0	-17.8	8.0	18.0	-6.4	-8.9	11.3	11.4	-8.7	-8.7	10.9	10.8	-3.9	-0.5	9.0	9.4
Palo Verde	-2.3	-15.0	7.0	16.0	-4.3	-7.1	9.3	10.5	-7.0	-7.3	10.3	10.5	-3.3	0.3	9.2	9.9
Joe Neal	-8.0	-20.0	9.7	20.1	-9.1	-11.3	12.2	13.2	-11.6	-11.1	12.5	12.1	-3.6	0.6	9.2	9.1
Green Valley	-2.3	-15.6	7.2	16.6	-5.7	-10.0	9.1	11.4	-5.7	-6.1	9.9	10.2	-0.1	2.0	11.0	11.8
Jerome Mack-NCORE	-7.3	-19.5	8.7	19.6	-5.9	-9.6	9.7	11.7	-9.2	-9.4	10.8	11.9	-3.9	-1.1	10.2	10.0
Boulder City	-2.4	-16.0	6.5	16.2	-0.7	-7.2	7.9	8.0	-0.8	-3.0	9.3	10.1	-2.9	-3.8	11.0	10.9
Jean	-3.2	-16.5	6.7	16.7	-0.3	-7.9	7.8	9.3	-4.5	-6.9	8.5	9.0	-0.3	-1.6	9.9	8.9
J.D. Smith	-8.7	-20.9	9.8	21.1	-9.5	-13.4	12.2	14.5	-10.4	-10.6	11.6	12.5	-3.8	-0.7	9.9	9.6
SM Youth Camp	-5.1	-19.7	9.5	19.7	-4.3	-9.2	9.1	11.3	-6.0	-9.2	8.7	10.1	-0.1	1.6	9.1	9.7
Indian Springs	-0.8	-15.9	9.5	16.6	0.5	-5.4	9.6	10.6	-2.4	-4.6	9.3	10.0	2.0	3.8	9.6	10.2
LV Paiute	-4.5	-17.3	8.1	17.5	-6.6	-10.0	10.8	11.5	-8.8	-9.3	10.3	10.4	1.2	4.3	9.0	9.7

These results indicate that the final base case performed typically well during May through June and continued to perform notably well during August. The remaining systematic under prediction tendency, while much smaller than the initial base case, continued to suggest a consistent source of error.

Figure 8-29 displays spatial maps of site-specific monthly NMB patterns for MDA8 ozone across the CC4c2 domain, for both the initial and final base case simulations. In this figure, NMB was determined from all days without the 60 ppb cutoff applied, so the maps are consistent with the data in Table 8-13. These plots show the systematic negative bias throughout the summer with the progressive improvement through August. Again, the statistical improvement in bias in May and June is notable.

Tables 8-14a and 14b list monthly NMB and NME statistical performance for MDA8 ozone for selected monitoring sites across the Mojave Desert of Southern California. These sites monitor the air mass that is often transported between the Los Angeles basin and the LVV. Simulated MDA8 ozone for these statistics were taken from the 12US2 grid. While slightly larger biases are evident than for LVV sites in both initial and final base cases, these results also showed a substantial improvement during May and June in the final base case statistics.

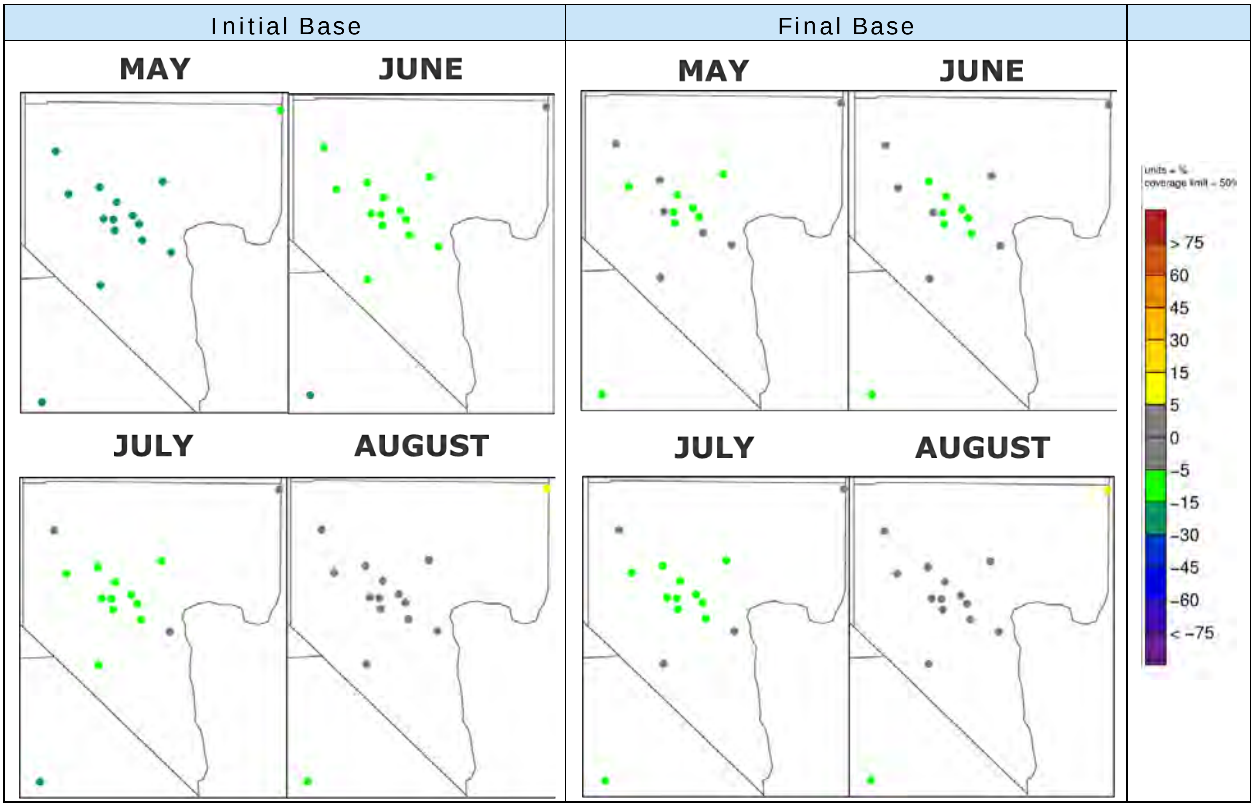


Figure 8-29. Map of site-specific monthly normalized mean bias (NMB) patterns for MDA8 ozone within the CC4c2 domain. Initial base case (left) and final base case (right).

Table 8-14a. Monthly model performance statistics for MDA8 ozone over all days and for selected monitoring sites across the Mojave Desert of Southern California. Normalized mean bias (NMB) and normalized mean unsigned error (NME, also referred to as gross error) are shown with color coding indicating statistics outside performance criteria (red), between goals and criteria (yellow) and within goals (green). Results from the Clark County initial and final base case simulations are compared.

Month	MDA8 Ozone (no cutoff)			
	NMB (%)		NME (%)	
	Base2	Base	Base2	Base
May	-6.0	-17.5	9.5	18.0
June	-6.4	-13.3	13.2	17.2
July	-10.0	-12.2	14.9	16.3
Aug	-5.4	-6.0	14.6	15.1
May-Aug	-7.0	-12.1	13.1	16.6

Table 8-14b. As in Table 8-14a, but for all sites and days when monitored MDA8 ozone exceeded 60 ppb.

Month	MDA8 Ozone (60 ppb cutoff)			
	NMB (%)		NME (%)	
	Base2	Base	Base2	Base
May	-10.9	-19.3	11.6	19.4
June	-10.0	-16.5	13.1	18.0
July	-14.3	-16.4	15.3	17.1
Aug	-11.1	-11.5	13.4	14.2
May-Aug	-11.7	-15.5	13.6	16.9

Figure 8-30 presents spatial maps of site-specific monthly NMB for the same selected monitoring sites across the Mojave Desert, for both the initial and final base case simulations. In this figure, NMB was determined from all days without the 60 ppb cutoff applied, so the maps are consistent with the data in Table 14a. The plots show the general pattern of systematic negative bias across the region and the improvements achieved in May and June in the final base case results. The remaining bias continued to implicate a lack of regional ozone and associated transport into the LVV.

Figure 8-31 presents time series of observed and simulated MDA8 ozone during the May through August modeling period at two representative monitoring sites. Results from the initial and final base cases are compared. Again, the improvements in the final base case during May and early June from the use of alternative boundary conditions from CAM-Chem are evident, while the two simulations tracked each other more closely in July and August. Performance in replicating the highest peak days was not especially skillful in any month, but the final base case tended to reduce occasional over predictions on non-event dates in August.

8.5.3 Analysis of Ozone Precursors

As described above, the final base case included the modified spatial allocation of NOx emissions from LTO cycles at Reid Airport consistent with the SENS1 sensitivity test. Comparisons to NO_2 observations at five central LVV monitoring sites, and effects to local ozone patterns, are documented in the section describing SENS1 results. To recap those results, elevating Reid Airport emissions reduced the overall surface NO_2 over prediction bias but did not ameliorate it entirely at neighborhood monitors. The impact to diurnal NO_2 concentrations was substantial during certain hours of the day with largest reductions at sites closest to Reid Airport, especially during the daytime and evening commute hours. No additional NOx emission modifications were applied in the final base case. Therefore, the detailed NOx performance evaluation is not repeated here.

As described above, our analyses and sensitivity tests involving alternative biogenic emission models helped to bracket the ozone impacts from biogenic VOC within the LVV. Ultimately, we ascertained that ozone production from the dearth of biogenic emissions in the desert environment is likely minimal given very low isoprene concentrations measured during the 2021 field study. Figure 8-32 compares predicted isoprene concentrations on a specific summer day among the different biogenic emission tests conducted in this study. Given similar meteorological conditions day-to-day, the examples in Figure 8-32 were consistent with other days of the modeling period. The choice of 10 AM PST in these plots was typically the hour during which predicted isoprene was maximum before deep boundary layer mixing and chemistry reduced concentrations substantially. Isoprene is not emitted during nighttime hours.

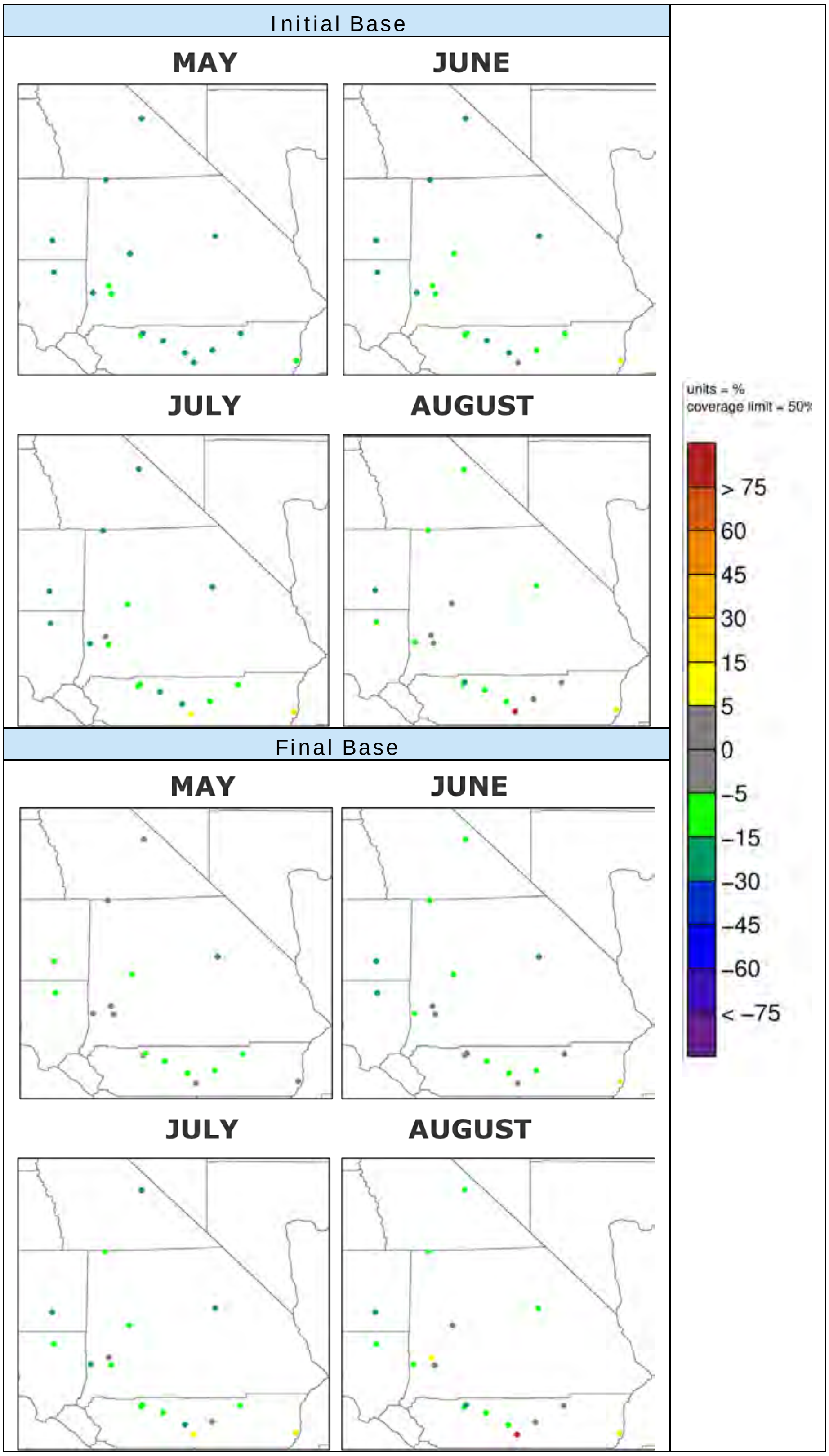


Figure 8-30. Map of site-specific monthly normalized mean bias (NMB) patterns for MDA8 ozone across the Mojave Desert of the southern California portion of the 12US2 domain. Initial base case (top) and final base case (bottom).

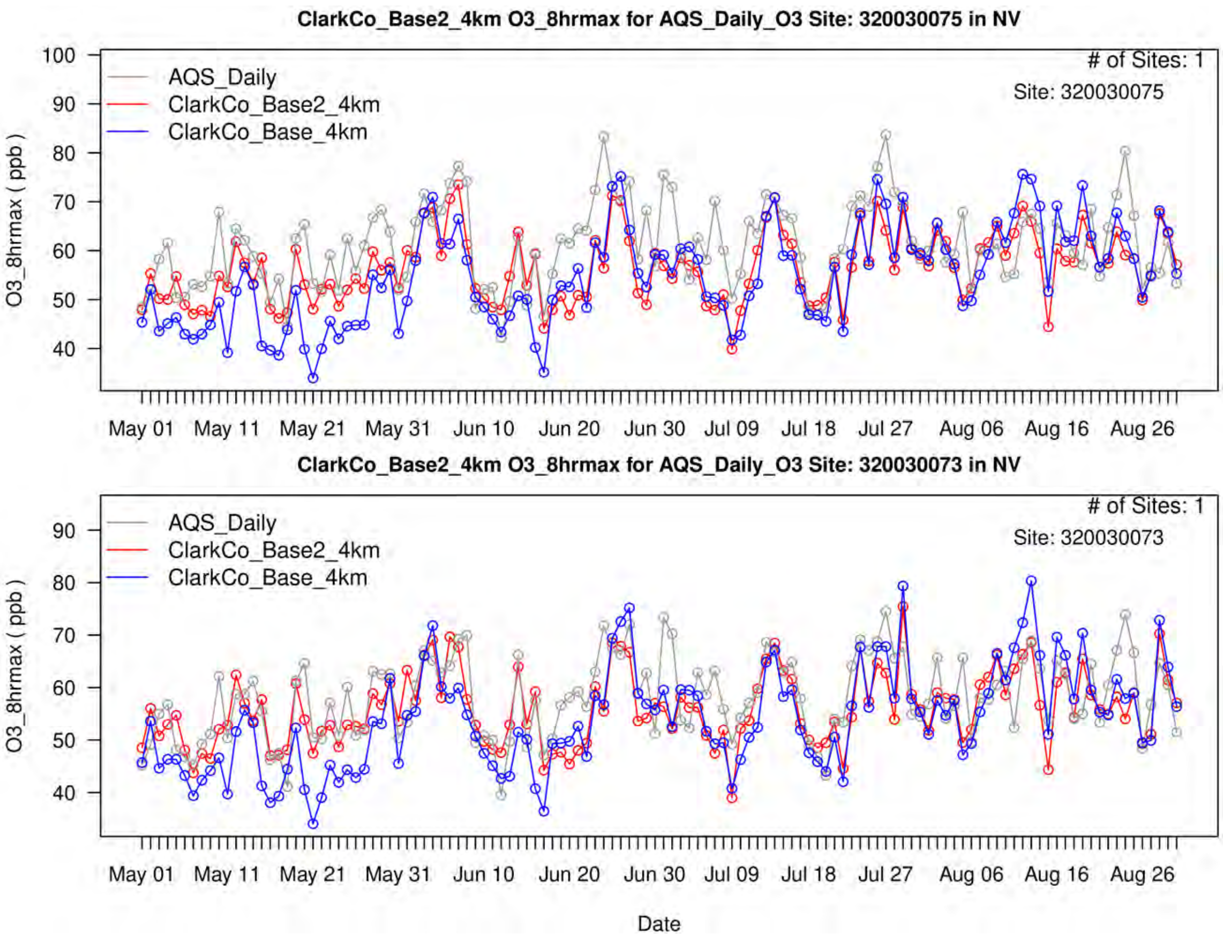


Figure 8-31. Time series of MDA8 ozone over the entire modeling period at the Joe Neal (top) and Palo Verde (bottom) monitoring sites. Daily AQS measurements are shown in grey, the modeled final base case results are shown in red, and the initial base case results are shown in blue.

The initial base case clearly over predicted morning isoprene concentrations within the urban area at 1-2 ppb whereas 2021 measurements ranged over a few tenths of a ppb. BEIS4 resulted in large urban isoprene under predictions of around 0.01 ppb, while BEIS3.6 resulted in the best agreement (0.25 ppb) but led to ozone over predictions in August. However, BEIS3.6 resulted in rural isoprene concentrations of 1 ppb or more, which were massively over predicted relative to 2021 isoprene measurements of <0.01 ppb measured outside of Las Vegas. We believe that the urban 0.25 ppb isoprene achieved in SENS4 (BEIS3.6) and the resulting ozone over predictions were caused by the very high rural biogenic emission transported into the NOx-rich urban area. At this point we conclude that there is far too much uncertainty in the biogenic models to know whether any of them appropriately estimate rural and urban VOC emissions in the desert environment of the southwestern US.

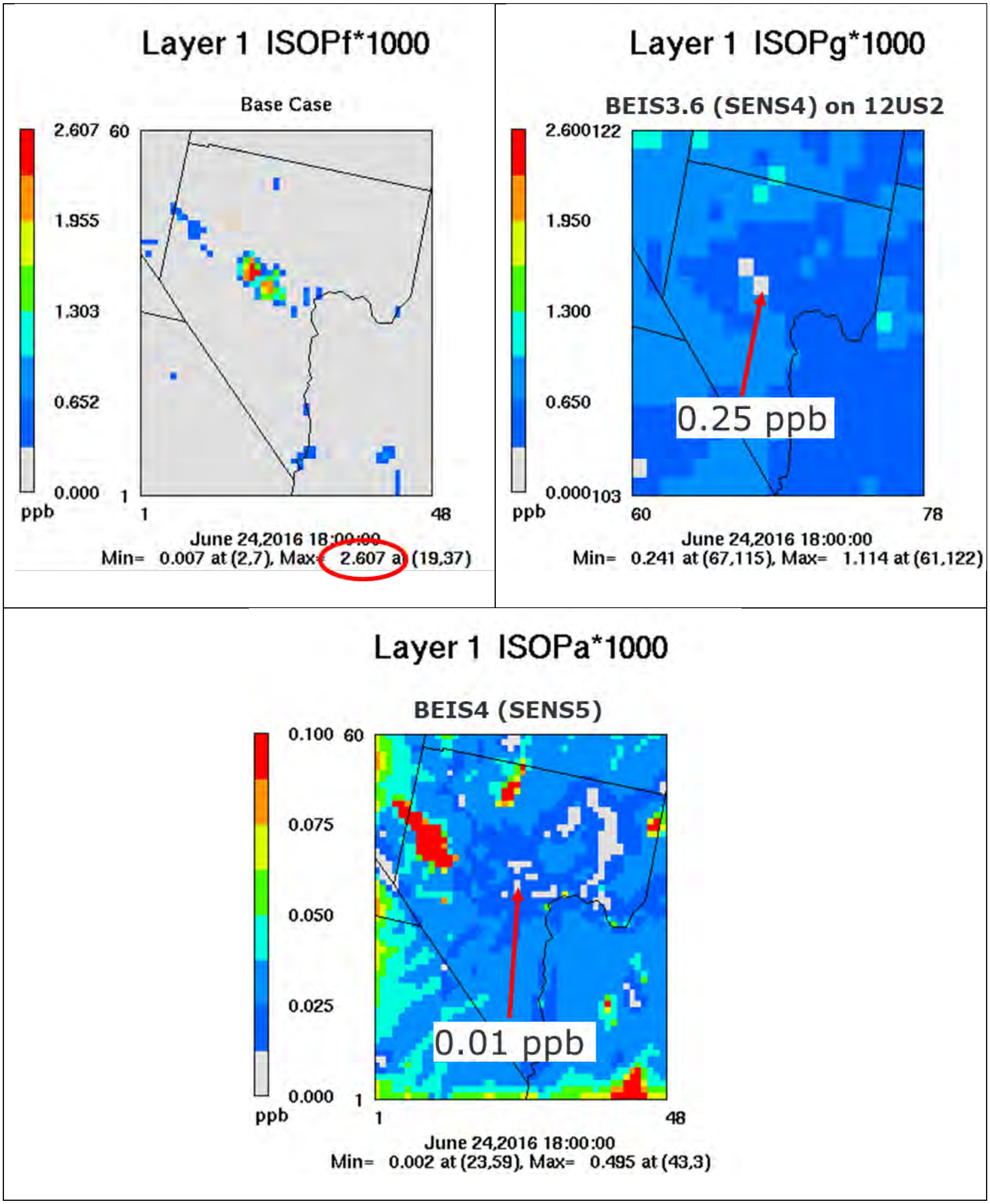


Figure 8-32. Predicted isoprene concentrations at 10 AM PST, June 24 2016, from three CAMx simulations using different versions of the BEIS biogenic emissions model. Measured isoprene concentrations in Las Vegas during 2021 ranged over a few tenths of a ppb (NOAA, 2022) but rural isoprene was measured below 0.01 ppb. The initial base case used BEIS3.7 whereas the final base case used BEIS4. See text for details about each simulation.

8.5.4 Analysis of Highest Observed Ozone Days

Table 8-15 ranks the 26 highest observed ozone days exceeding 70 ppb during summer 2016 according to peak site concentrations in the LVV. Site- and date-paired model predictions from the initial and final base cases are also listed for comparison. The table notes which days are expected to be influenced by regional wildfires versus local production and regional anthropogenic transport, according to previous analyses conducted by DES/DAQ.

Results show that all days remained under predicted, with 8 of 26 days within 5 ppb and average under predictions of around 10 ppb. Considering all days, the average peak observation was 75.4 ppb versus the average paired prediction of 64.7 ppb in the initial base case (absolute and normalized bias of -10.7 ppb and -14%, respectively) and 64.2 ppb in the final base case (absolute and normalized bias of -11.2 ppb and -15%, respectively). Results were similar when considering only days not influenced by wildfires. On those 15 days, the average peak observation was 74.2 ppb versus the average paired prediction of 64.4 ppb in the final base case (absolute and normalized bias of -9.8 ppb and -13%, respectively).

Figure 8-33 shows spatial plots of MDA8 ozone on each of the 26 high ozone dates with observations overlaid as colored circles to visually aid in prediction-observation comparisons. Based solely on visual inspection, well performing dates included: June 3, 6, 7, 25, and 26; July 13, 14 and 29; August 13. June 6 exhibited an over prediction tendency, but all other dates displayed in Figure 8-33 exhibited under predictions at nearly all sites.

Table 8-15. Observed and predicted MDA8 ozone on days when at least one site monitored an exceedance above 70 ppb. The table shows the observed ozone at the peak site each day, ranked from highest to lowest, and the paired predicted values. Dates noted in red are expected to be influenced by regional wildfires. Dates noted in blue are expected to be caused mainly by local production and upwind transport from anthropogenic sources. Dates noted in black have not been assessed with respect to likely causes. Orange highlighted predictions are under predicted by more than 5 ppb, bold predictions in the final base case are higher than the initial base case.

Site Name	Site ID	Date	Observed	Base	Base2
Apex	3200300221	6/24/2016	84.0	60.1	58.9
Joe Neal	3200300751	7/27/2016	83.6	69.6	62.4
Joe Neal	3200300751	8/24/2016	80.4	63.0	58.2
LV Paiute	3200380001	7/1/2016	80.3	65.2	61.9
LV Paiute	3200380001	6/7/2016	80.1	72.1	78.1
LV Paiute	3200380001	7/26/2016	79.6	75.2	71.5
LV Paiute	3200380001	6/8/2016	76.8	60.2	62.7
SM Youth Camp	3200377714	5/20/2016	76.5	37.2	52.7
LV Paiute	3200380001	8/23/2016	75.9	71.5	66.5
Paul Meyer	3200300431	7/29/2016	75.5	77.9	71.8
LV Paiute	3200380001	7/2/2016	75.4	56.2	55.3
LV Paiute	3200380001	6/25/2016	74.3	73.8	72.0
Joe Neal	3200300751	6/27/2016	74.1	64.2	61.3
LV Paiute	3200380001	6/3/2016	74.1	72.4	71.9
Indian Springs	3200377721	7/25/2016	73.9	61.2	61.1
Joe Neal	3200300751	6/6/2016	73.8	61.4	69.9
SM Youth Camp	3200377714	8/25/2016	73.4	61.8	62.8
Apex	3200320021	7/28/2016	73.0	59.7	55.7
LV Paiute	3200380001	7/13/2016	73.0	71.3	70.7
Joe Neal	3200300751	6/23/2016	72.4	61.6	61.7
LV Paiute	3200380001	6/26/2016	72.4	73.9	70.3
LV Paiute	3200380001	7/14/2016	72.4	72.6	72.2
LV Paiute	3200380001	7/24/2016	72.3	62.2	62.7
SM Youth Camp	3200377714	6/14/2016	71.5	50.7	62.8
Paul Meyer	3200300431	8/13/2016	70.8	77.2	65.5
Joe Neal	3200300751	7/7/2016	70.1	50.3	47.8

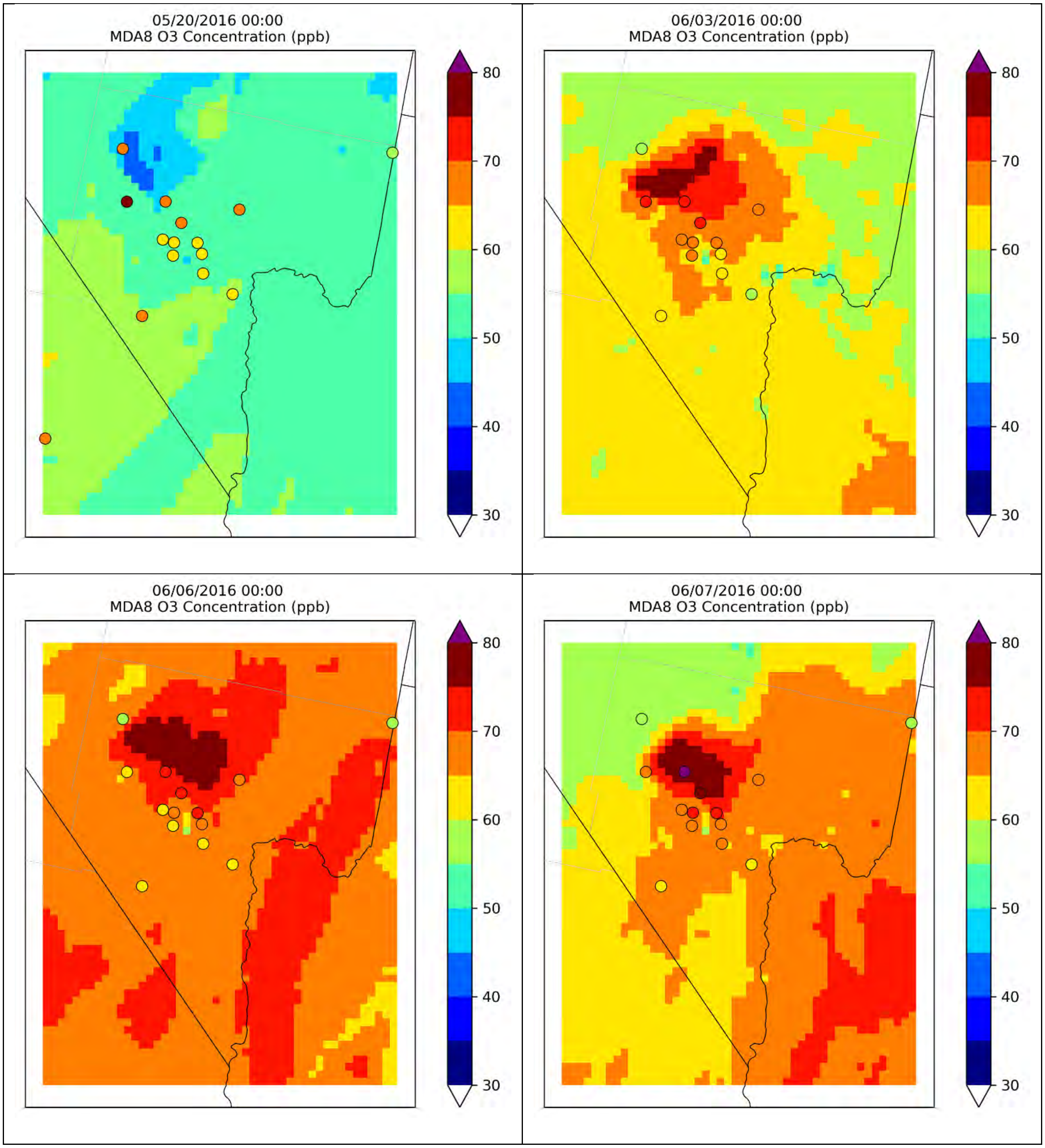


Figure 8-33. Spatial plots of predicted MDA8 ozone on 26 high ozone dates in 2016 when at least one peak measurement exceeded 70 ppb. Observations are overlaid as colored circles.

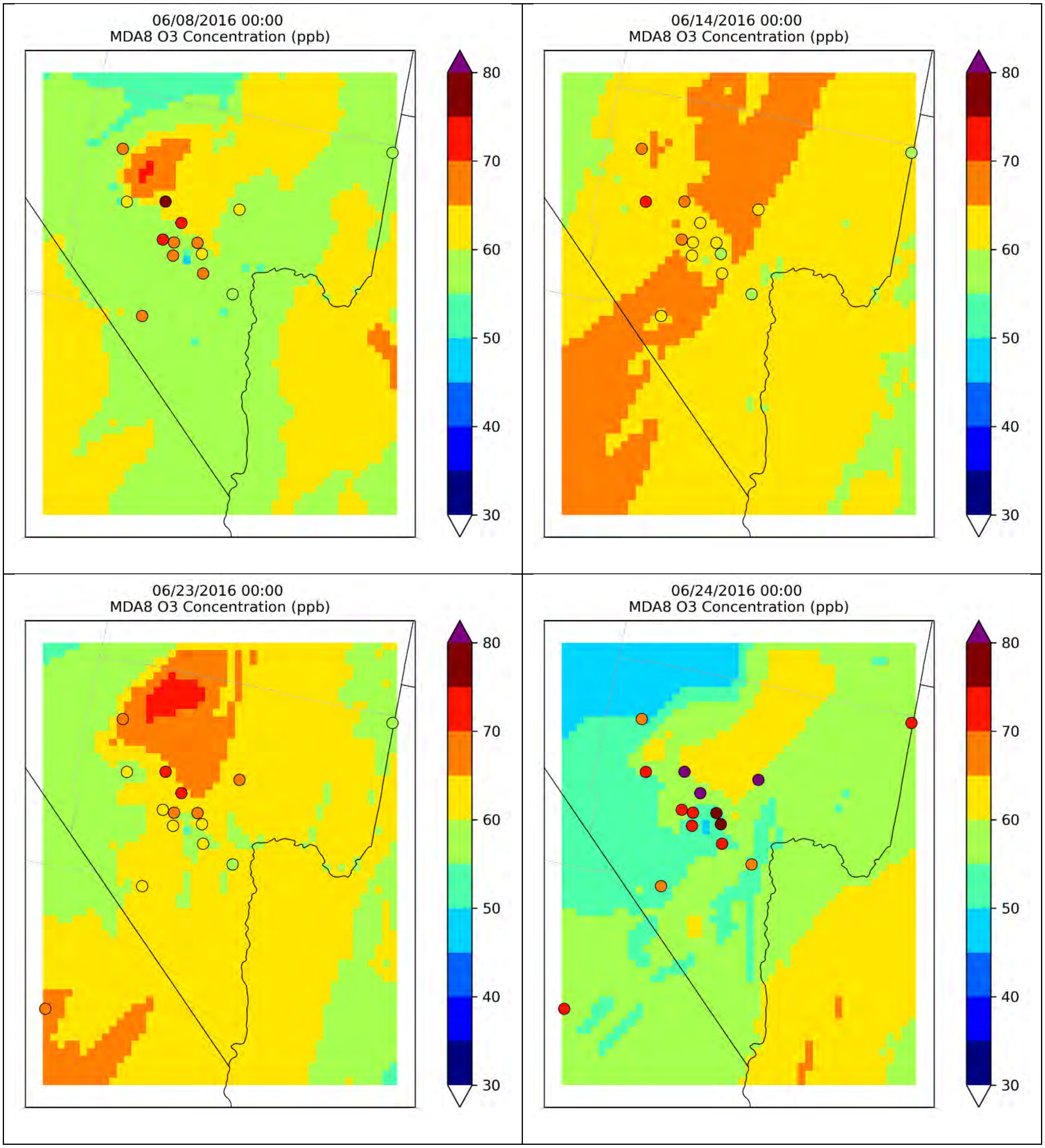


Figure 8-33 (continued).

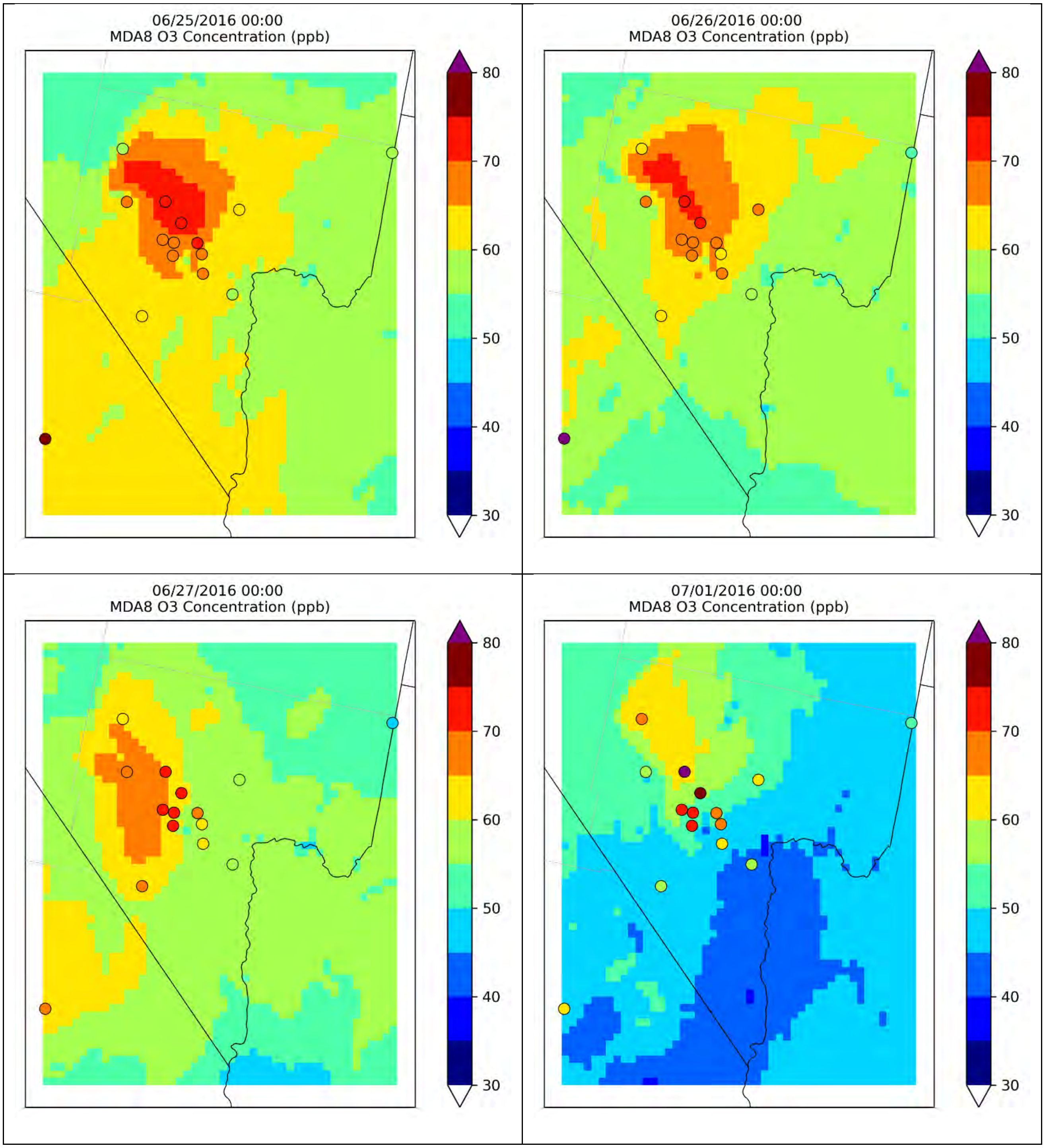


Figure 8-33 (continued).

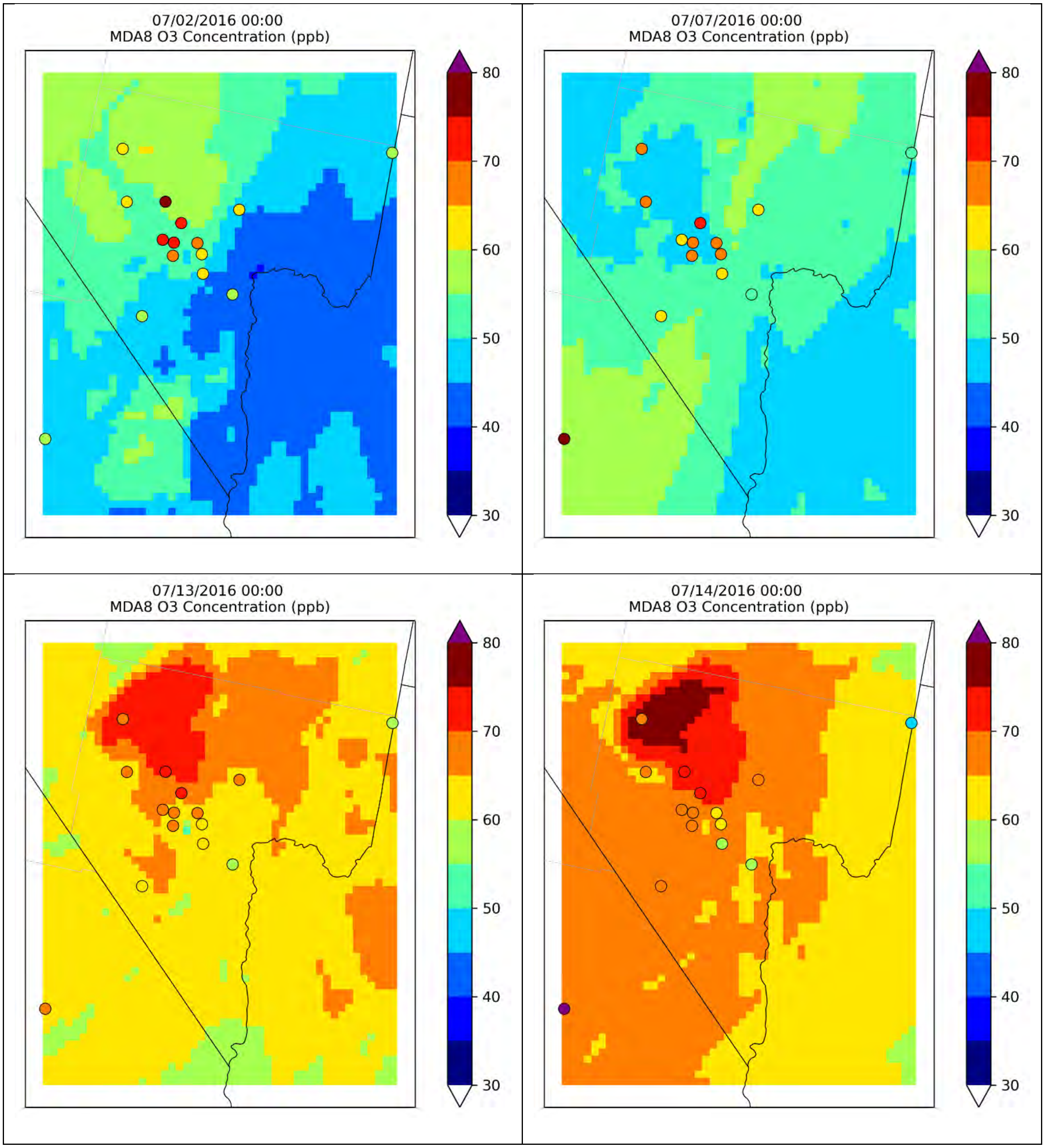


Figure 8-33 (continued).

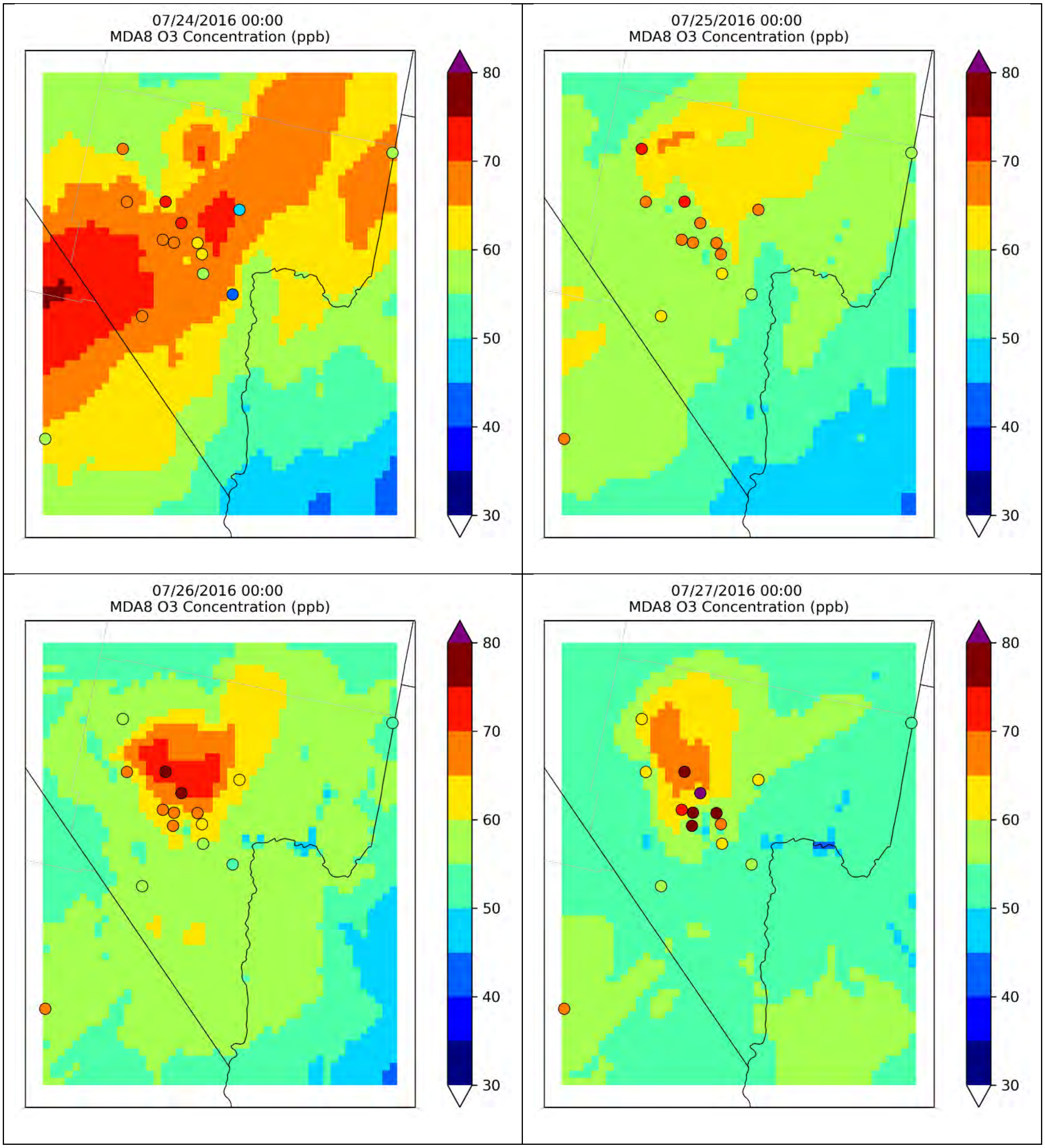


Figure 8-33 (continued).

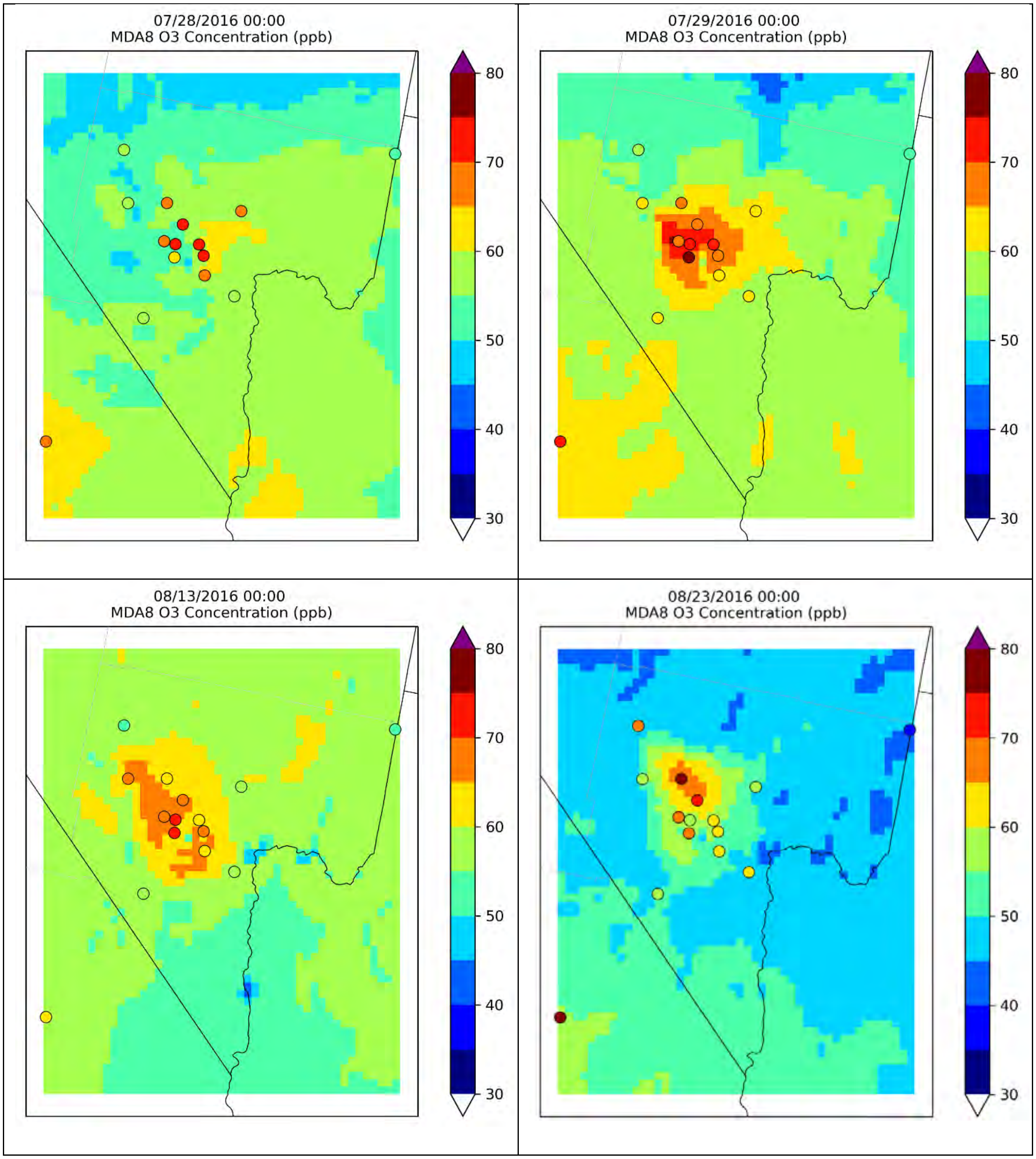


Figure 8-33 (continued).

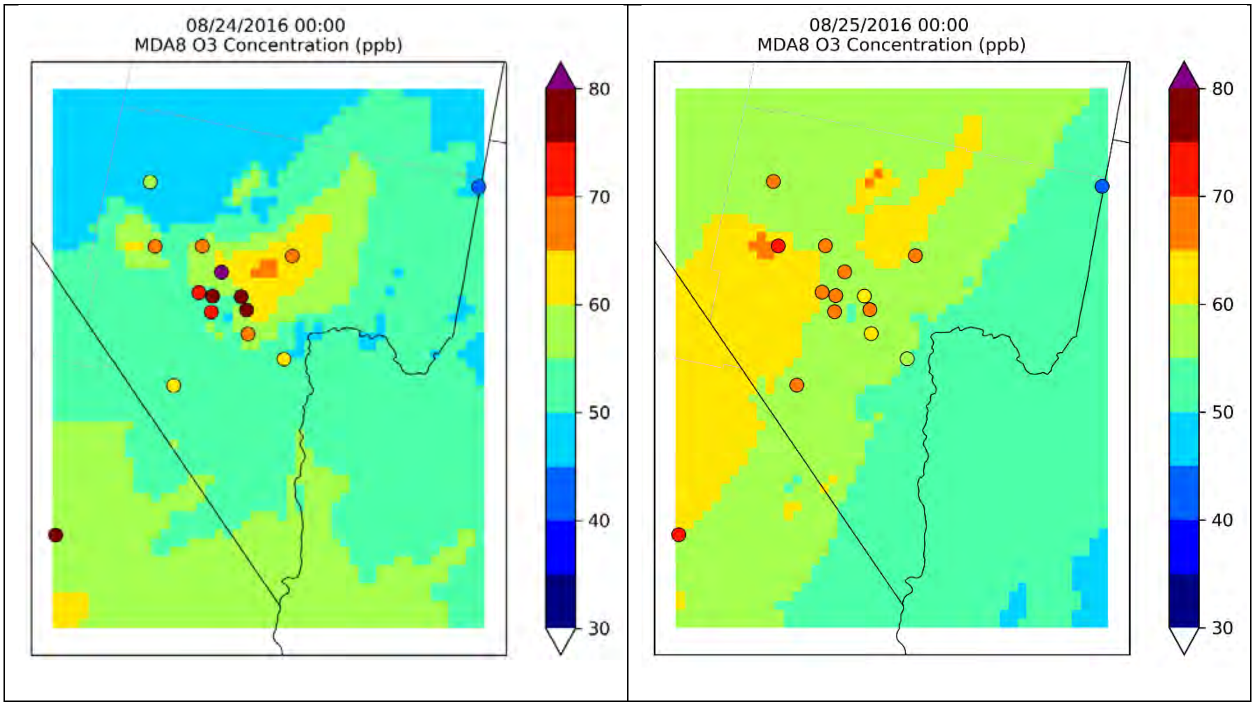


Figure 8-33 (concluded).

8.5.5 Analysis of Highest Predicted Ozone Days

EPA (2018a) modeling guidance provides detailed procedures on using base and future year modeling results to project future year ozone DVs – referred to as a "modeled attainment test". EPA has developed the Software for Model Attainment Test - Community Edition (SMAT-CE; EPA, 2022g) that codifies the recommended procedures. Modeling output for the base and future year is used in a relative sense to scale the observed base year ozone DV to a future year ozone DV at each monitoring site. The model-derived Relative Response Factor at each site is defined as the ratio of the average modeled MDA8 future ozone concentration to the average modeled MDA8 base ozone concentrations. The averages are determined for the 10 days with the highest modeled base year MDA8 ozone concentrations near the monitor (i.e., within a 3x3 array of grid cells), provided those values are all ≥60 ppb and regardless of observed conditions on those days. If there are less than 10 modeled days meeting this criterion, then only the days meeting this criterion are used in the average, provided there are at least 5 days available for the RRF calculation. If there are less than 5 days meeting this criterion, EPA recommends that RRFs not be calculated for the given site and the regional EPA office should be consulted if the site is an important high DV site.

EPA guidance allows some flexibility to exclude "exceptional event like" days (i.e., days that might not qualify as official exceptional events such as wildfire influences) from the DV projections with appropriate justification. There are two approaches to account for exceptional event like days in the attainment year DVF projection: (1) remove such days from the base year DVB calculation so that the DV more faithfully reflects local to regional anthropogenic ozone conditions and patterns; (2) remove such days from the list of modeled highest 10 base year ozone days in the RRF calculation so that the projection more faithfully reflects impacts from local to regional emission reductions.

In this section we analyze the top 10 modeled days at each of the 6 monitoring sites within the CCNAA that reported 2018-2020 DVs (Figure 8-34). We also note the number of days in each list that correspond to observed days that exceeded 70 ppb (Table 8-15, Figure 8-33) along with current expectations for their cause.

Figure 8-34 shows the spatial distribution of 2018-2020 DVs reported at ozone monitoring sites within and immediately surrounding the CCNAA. Sites shown in grey did not report ozone DVs, including LV Paiute and J.D. Smith. Thus only 6 sites recorded DVs within the CCNAA while 8 ozone monitoring sites reported ozone measurements in 2016. Four sites within Las Vegas and near Henderson exceeded the 2015 ozone NAAQS, as shown in dark blue (Joe Neal, 74 ppb; Walter Johnson, 73 ppb; Paul Meyer, 73 ppb, Green Valley, 72 ppb). These 4 sites are critical in the 2023 SMAT-CE DV projections.

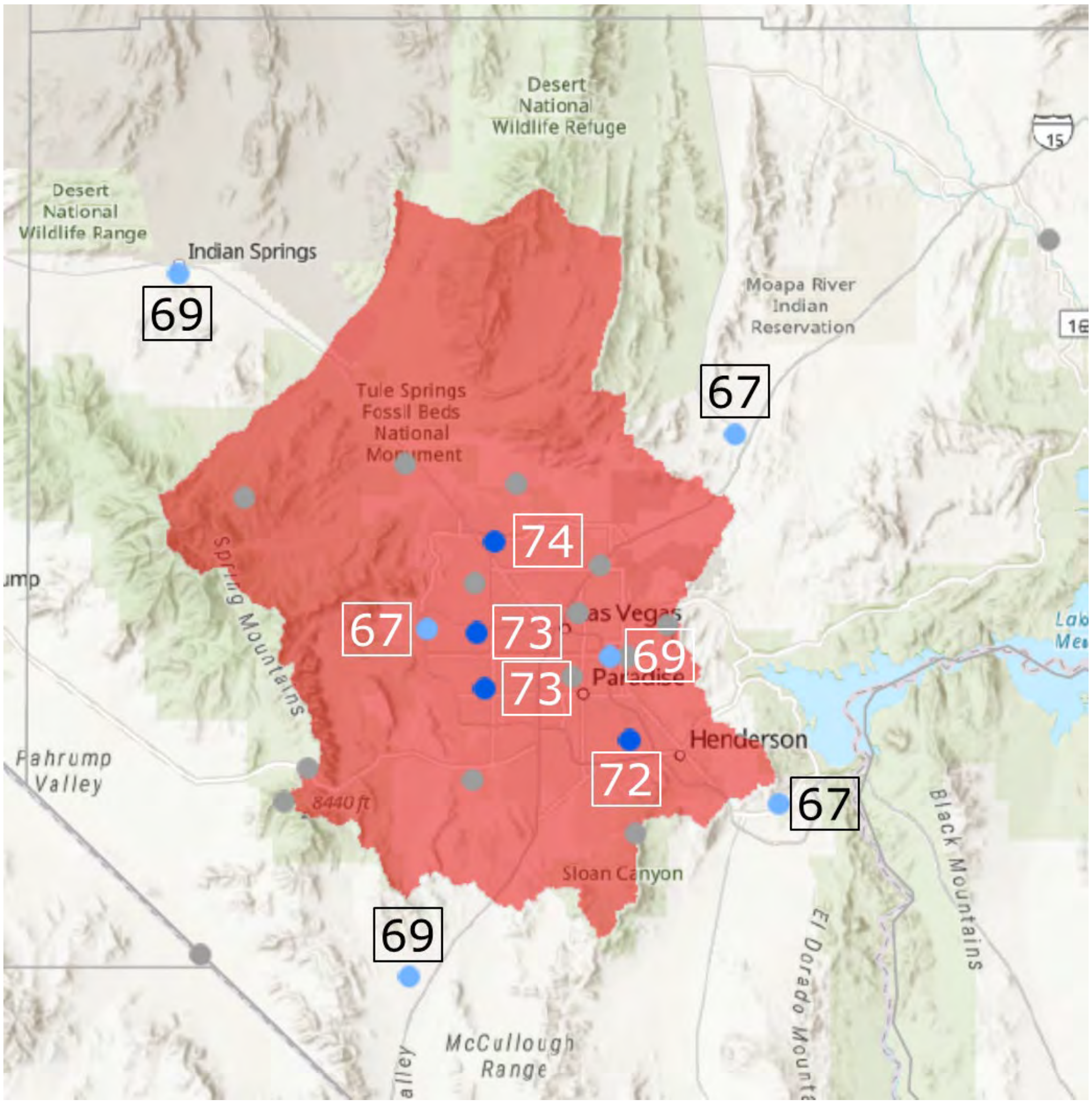


Figure 8-34. Spatial distribution of 2020 design values at 10 ozone monitoring sites within and immediately surrounding the CCNAA (depicted by orange shading). Sites shown in grey did not measure or report ozone design values. Background image from https://epa.maps.arcgis.com/apps/MapSeries/index.html?appid=bc6f3a961ea14013afb2e0d0e450b0d1.

Tables 8-16 through 8-21 present the top 10 modeled ozone days in the final base case scenario at each of 6 CCNAA monitors. All sites include 10 modeled days above 60 ppb, and all tend to include a similar set of dates in different orders. Results are summarized below.

Joe Neal: 7 observed exceedance days in the top 10 list (3 fire-influenced days, 2 local/transport days, 2 undetermined days).

Average observation / prediction: 69.9 / 69.2 ppb
Bias absolute / normalized: -0.6 ppb / -0.9%
Error absolute / normalized: 3.9 ppb / 5.6%

Table 8-16. Top 10 modeled MDA8 ozone days in the final base case scenario at the Joe Neal monitoring site, and date-paired observed MDA8 ozone. Exceedance dates noted in red are expected to be influenced by regional wildfires. Exceedance dates noted in blue are expected to be caused mainly by local production and upwind transport from anthropogenic sources. Exceedance dates noted in bold have not been assessed with respect to likely causes. Remaining dates did not exceed 70 ppb at any monitoring site in 2016.

Date	Observed	Predicted	Difference
6/7/2016	77.3	72.3	-4.9
6/25/2016	73.0	70.7	-2.3
7/14/2016	70.8	70.0	-0.7
6/6/2016	73.8	69.9	-3.8
6/26/2016	70.0	69.3	-0.7
7/26/2016	77.1	68.6	-8.6
8/12/2016	65.9	68.3	2.4
7/29/2016	69.6	68.2	-1.5
6/4/2016	65.9	68.1	2.2
8/28/2016	55.4	67.0	11.6

Palo Verde: 8 observed exceedance days in the top 10 list: (3 fire-influenced days, 2 local/transport days, 3 undetermined days).

Average observation / prediction: 67.0 / 68.6 ppb
Bias absolute / normalized: 1.7 ppb / 2.5%
Error absolute / normalized: 2.7 ppb / 4.0%

Table 8-17. As in Table 8-16, but at the Palo Verde monitoring site.

Date	Observed	Predicted	Difference
7/29/2016	67.8	74.4	6.6
8/28/2016	64.6	69.3	4.6
6/6/2016	64.1	69.2	5.1
7/14/2016	66.8	68.1	1.4
6/4/2016	65.1	68.0	2.9
6/25/2016	67.6	68.0	0.3
7/24/2016	69.1	67.7	-1.4
8/13/2016	68.9	67.4	-1.5
6/7/2016	69.3	67.0	-2.3
6/26/2016	66.3	67.0	0.7

Walter Johnson: 8 observed exceedance days in the top 10 list (3 fire-influenced days, 2 local/transport days, 3 undetermined days).

Average observation / prediction: 68.0 / 68.1 ppb
Bias absolute / normalized: 0.1 ppb / 0.1%
Error absolute / normalized: 2.4 ppb / 3.5%

Table 8-18. As in Table 8-16, but at the Walter Johnson monitoring site.

Date	Observed	Predicted	Difference
7/29/2016	71.9	73.9	2.0
6/6/2016	65.6	68.8	3.2
7/24/2016	69.1	68.5	-0.6
7/14/2016	67.4	68.0	0.6
8/28/2016	64.1	67.8	3.7
6/25/2016	69.5	67.2	-2.3
6/4/2016	63.9	66.8	2.9
6/7/2016	70.4	66.6	-3.7
8/13/2016	70.1	66.5	-3.6
6/26/2016	67.6	66.4	-1.3

Paul Meyer: 7 observed exceedance days in the top 10 list (2 fire-influenced days, 2 local/transport days, 3 undetermined days).

Average observation / prediction: 67.1 / 66.6 ppb
Bias absolute / normalized: -0.5 ppb / -0.7%
Error absolute / normalized: 2.8 ppb / 4.2%

Table 8-19. As in Table 8-16, but at the Paul Meyer monitoring site.

Date	Observed	Predicted	Difference
7/29/2016	75.5	71.8	-3.7
6/6/2016	64.8	68.0	3.3
8/28/2016	64.5	66.7	2.2
7/14/2016	65.8	66.7	0.9
6/25/2016	68.1	65.9	-2.2
6/7/2016	69.0	65.9	-3.1
6/4/2016	64.9	65.6	0.7
8/13/2016	70.8	65.5	-5.3
6/26/2016	67.8	65.3	-2.4
8/9/2016	60.1	64.7	4.6

Jerome Mack: 7 observed exceedance days in the top 10 list (3 fire-influenced days, 2 local/transport days, 2 undetermined days).

Average observation / prediction: 64.1 / 65.8 ppb
Bias absolute / normalized: 1.7 ppb / 2.7%
Error absolute / normalized: 3.4 ppb / 5.3%

Table 8-20. As in Table 8-16, but at the Jerome Mack monitoring site.

Date	Observed	Predicted	Difference
7/24/2016	61.1	68.0	6.9
6/7/2016	67.9	67.4	-0.5
6/6/2016	67.0	67.0	0.0
7/14/2016	62.8	66.8	4.0
7/29/2016	67.9	66.1	-1.8
8/12/2016	67.9	65.0	-2.9
8/9/2016	57.3	64.9	7.7
6/25/2016	67.5	64.3	-3.2
6/26/2016	63.1	64.2	1.1
6/4/2016	58.1	63.9	5.8

Green Valley: 7 observed exceedance days in the top 10 list (2 fire-influenced days, 2 local/transport days, 3 undetermined days).

Average observation / prediction: 61.8 / 65.4 ppb
Bias absolute / normalized: 3.6 ppb / 5.8%
Error absolute / normalized: 4.4 ppb / 7.1%

Table 8-21. As in Table 8-16, but at the Green Valley monitoring site.

Date	Observed	Predicted	Difference
7/24/2016	57.1	69.1	12.0
7/14/2016	59.4	66.2	6.8
8/13/2016	62.3	65.8	3.6
6/6/2016	64.0	65.7	1.7
7/15/2016	64.9	65.6	0.8
7/16/2016	62.6	64.8	2.2
6/14/2016	61.9	64.3	2.4
8/9/2016	54.6	64.3	9.7
7/29/2016	63.3	64.3	1.0
6/7/2016	68.0	64.0	-4.0

9.0 FUTURE YEAR MODELING

This Section describes the CAMx 2023 future year base case modeling configuration, the methods to apply the modeled attainment test that projects the 2016-2018 average DV to the 2023 future year, and DV projection results. The methodology closely followed the approach described in EPA modeling guidance (EPA, 2018a) and in the Modeling Protocol developed during the early phases of this project (Ramboll, 2022a).

9.1 Summary of Results

The 2023 future base case was used in combination with the final 2016 base case to project 2016-2018 DVs to 2023 at each monitoring site in the basin, based on relative scaling factors that were developed from ozone concentration ratios between the two model runs. Results from the modeled attainment test are summarized below:

- According to the method codified by EPA (2022g), no exceedances were projected in 2023 based on the 2023 future base CAMx simulation. The peak 3-year average projected 2023 DV was 69 ppb at Joe Neal.
- Comparison of the modeled 2016 ozone against the 2016-2018 average DV at each site shows that the modeled spatial pattern of high and low ozone was well represented in the CAMx results. This adds some weight to the argument that the model adequately replicated the processes that form and disperse ozone throughout the basin, and in turn the spatial distribution of the respective RRFs was reasonably represented as well.
- The amount of predicted regional ozone streaming into the CCNAA from southern California was an important component in the 2023 projection. The accuracy of the 2023 projection depends in large measure on the accuracy of the regional anthropogenic emission inventory, wildfire influences, and the chemistry and dispersion/transport patterns characterized in the CAMx simulations.

9.2 Future Year Model Configuration

The CCNAA is currently classified as a Moderate Nonattainment Area under the 2015 ozone NAAQS because 2018-2020 ozone DVs failed to attain the standard by the August 3, 2021 attainment date for Marginal areas (Figure 8-34). Moderate areas must attain the NAAQS by August 3, 2024 based on the 2021-2023 DV, or risk further bump-up to Severe. Thus, attainment demonstration modeling was conducted for the 2023 future year.

The final 2016 base case CAMx configuration was repeated but using 2023 base case anthropogenic emission inputs for each of the three modeling domains (36US3, 12US2, CC4c2). All other inputs were the same as the final 2016 base case simulation, including meteorology, natural emissions, 36US3 boundary conditions, and photolysis inputs. This model configuration was otherwise identical to the final 2016 sensitivity run called “SENS6” (Table 9-1).

The following natural emission sources remained unchanged from the 2016 base year:

- Biogenic emissions from the EPA BEIS4/BELD6 model;
- Lighting NOx emissions;
- Open Land Fires (Wildfires, Prescribed Burns and Agricultural Burning)

As described in Section 6, the EPA 2016v2 MP provided all of the 2023 model-ready anthropogenic emission estimates for the 36US3 and 12US2 modeling grids (EPA, 2022b). A combination of 2016v2 emissions and Clark County data were used to process 2023 model-ready anthropogenic emissions on the CC4c2 grid. The 2023 emissions inventory reflect local, state, and national rules that are currently known and "on-the-books." The 2023 future base case therefore does not include any additional control measures that are either planned or promulgated to begin during or after 2023.

9.3 Ozone Attainment Demonstration

EPA (2018a) modeling guidance includes detailed procedures on using base and future year modeling results to project future year ozone DVs – referred to as a "modeled attainment test". EPA has developed the Software for Model Attainment Test - Community Edition (SMAT-CE; EPA, 2022g) that codifies the recommended procedures.

9.3.1 Modeled Attainment Test

The SMAT-CE procedure is outlined in Chapter 4 of EPA's modeling guidance (EPA, 2018a, pages 99-110). PGM output for the base and future year is used in a relative sense to scale the base year ozone DV (DVB) to the future year ozone DV (DVF) at each monitoring site. The model-derived Relative Response Factor (RRF) is defined individually at each monitoring site as the ratio of average future MDA8 ozone concentration ($O3_{FY}$) to the average base MDA8 ozone concentrations ($O3_{BY}$), where the average is over the same set of several modeled high ozone days. This is expressed mathematically below:

$$DVF = DVB \times RRF$$

$$RRF = \sum(O3_{FY}) / \sum(O3_{BY})$$

The site-specific DVB is defined as the three-year average ozone DV centered on the base modeling year. As each year's DV is itself defined as the three-year average of the 4th highest MDA8 ozone concentration each year (H4MDA8), the DVB is thus based on 5 years of H4MDA8 ozone concentrations centered on the base year, such that the central year is weighted by a factor of 3/5, the 2nd and 4th years are weighted by a factor of 2/5, and the 1st and 5th years are weighted by a factor of 1/5. This approach is EPA's way to account for interannual variability affecting DVs in and around the base year.

The CCNAA modeled base year is 2016 so the DVB at each site is defined from three years of ozone DVs as follows:

$$DVB_{2016} = (DV_{2014\text{-}2016} + DV_{2015\text{-}2017} + DV_{2016\text{-}2018}) / 3$$

or

$$DVB_{2016} = (H4MDA8_{2014} + 2xH4MDA8_{2015} + 3xH4MDA8_{2016} + 2xH4MDA8_{2017} + H4MDA8_{2018}) / 5$$

Table 9-1. CAMx model configuration for the CCNAA 2023 future base case simulation. Changes from the final 2016 base case are noted in red.

Model Component	CCNAA Application	Comment
Model Code	CAMx v7.20 - May 2022	
Modeling Period	May 1 – August 31, 2016	
Horizontal Grids		
Map Projection	Lambert Conic Conformal	EPA 2016 MP
36 km (36US3)	172 x 148 cells	EPA 2016 MP (1-way nesting)
12 km (12US2)	396 x 246 cells (no buffer cells)	EPA 2016 MP (2-way nesting)
4 km (CC4c2)	50 x 62 cells (with buffer cells)	CCNAA grid (2-way nesting)
Vertical Grid	35 layers	EPA 2016 MP, defined by WRF
Initial Conditions	36US3 IC April 1 from CAM-Chem, 12US2/CC4c2 IC May 1 from 36US3	
Boundary Conditions	36US3 BC from CAM-Chem, 12US2 BC from 36US3	
Time Zone	UTC	EPA 2016 MP
Emissions		
36/12 km Data Sources	EPA 2023fj from 2016v2 MP	
4 km Data Sources	EPA 2023fj from 2016v2 MP + 2023 Clark County Data, elevated Reid LTO emissions	
Models/Processing Tools	SMOKE, MOVES3, SMOKE-MOVES, BEIS4/BELD6	CCNAA grid
Plume-in-Grid	Off	No large point sources in high-resolution CCNAA grid
In-line Ix emissions	On	Oceanic halogens
Chemistry		
Gas Phase Chemistry	CB6r5	Latest mechanism available
Aerosol Chemistry	Active	Gas phase only
Meteorological Interface	WRFCAMx v5.2	
Horizontal Diffusion	Smagorinsky	Spatially variant K-theory
Vertical Diffusion	YSU Kv formulation + KVPATCH	Minimum Kv 0.1 to 1.0 m^2/s
ACM2	Off	Non-local boundary layer convection
Sub-grid Cloud Convection	Off	
Deposition		
Dry Deposition	Zhang03	
Wet Deposition	On	rain/snow/graupel
Surface Chemistry Model	Off	
Bi-directional Ammonia	Off	For aerosol chemistry
Numeric Solvers		
Gas Phase Solver	Euler Backward Iterative (EBI)	Default fast and accurate solver
Vertical Advection	Piecewise Parabolic Method (PPM)	Default
Horizontal Advection	Piecewise Parabolic Method (PPM)	Default
Integration Time Step	Wind speed dependent	~0.5-1 min (4 km), 1-5 min (12 km), 5-15 min (36 km)
Super Stepping	On	Maximizes time step selection

The RRF is determined from maximum MDA8 ozone concentrations near each monitor, averaged over 10 days with the highest base year modeled MDA8 ozone concentrations.

Near the Monitor: This means that the highest modeled base year MDA8 ozone is selected from one of a 3x3 array of grid cells centered on the monitor. The future year MDA8 ozone is selected from the same grid cell of the 3x3 array.

10 Highest Base Year MDA8 Ozone Days: Modeled MDA8 ozone concentrations are averaged over 10 days with the highest base year modeled ozone concentrations near the monitor, provided MDA8 ozone on the chosen days are each ≥60 ppb. If there are less than 10 days meeting this criterion, then only the days meeting this criterion are used in the average, provided there are at least 5 days available for the RRF calculation. If there are less than 5 days meeting this criterion, EPA recommends that RRFs not be calculated for the given site and the regional EPA office should be consulted if the site is an important high DV site.

9.3.2 Flexibility in RRF Calculations

EPA's guidance includes some flexibility to modify the recommended ozone DV projection procedure. There may be good reason why certain grid cells within the 3x3 array centered on the monitor may not be representative of conditions at the monitor; for example, if portions of the 3x3 array have different atmospheric conditions (over water) or the monitor is in an area with sharp terrain gradients.

Another consideration is to account for "exceptional event like" days (i.e., days that might not qualify as official exceptional events) such as wildfires. EPA (2019c) includes provisions for excluding such days with appropriate justification. There are two approaches to account for exceptional event like days in the attainment year DVF projection: (1) remove such days from the base year DVB calculation so that the DV more faithfully reflects local to regional anthropogenic ozone conditions and patterns; (2) remove such days from the list of modeled highest 10 base year ozone days in the RRF calculation so that the projection more faithfully reflects impacts from local to regional emission reductions. As described in the Modeling Protocol (Ramboll, 2022a) several days of 2016 may warrant exclusion, but it would be problematic to exclude a large number.

In the CCNAA attainment demonstration, any deviations in the modeled attainment test from EPA's recommended procedures have been documented and justified. The standard EPA method was always calculated as one of the projection approaches analyzed.

9.3.3 SMAT-CE Configuration

We applied SMAT-CE v2.1 (8/26/22) with the most current monitoring database from EPA containing 2002-2020 4th high MDA8 ozone for all official sites operating in Clark County. The SMAT-CE configuration involved defining the 2016-2018 3-year DV period for base monitored ozone (2014-2018 4th highs), choosing the maximum ozone within a 3x3 grid cell matrix around each monitor, and projecting DVs using the 3-year average DV and 3-year maximum DV at each monitor. The average is used for the standard attainment test, while maxima are used to identify any future maintenance monitors.

Figure 9-1 presents the settings reported in the SMAT-CE configuration file for the application described here. These settings are presented simply as a reference for documentation purposes; we refer the reader to the SMAT-CE User's Guide (EPA, 2022g) for additional information on each parameter setting. In general, our approach was to use default or standard settings throughout the setup menu. We made no special modifications to monitored data or specific selection of modeled days for the RRF calculation.

```
RunType=RunOzone
OutputFileDir=C:\Users\Documents\My SMAT-CE Files\Result\Output
OutputFileName=ClarkCo_O3SIP.cfg
scenarioName=ClarkCo_O3SIP
doPointEstimatesForecast=1
doQuarterlyModelData=1
doSpatialFieldEstimates=1
doBaseOnlyVNA=0
doFutureOnlyVNA=0
doSpatialFieldEstimatesGradAdj=1
doBaseOnlyEVNA=0
doFutureOnlyEVNA=0
doNeighborFileSpatial=1
doAutomaticallyExtract=1
doDesignValuePeriods=1
doMaxDesignValuePeriods=1
ozoneMonitorDataFile=C:\Users\Documents\My SMAT-CE Files\Data\SampleData\Monitor_data\
SMAT_OZONE_MAX4DV_STD70_2002_2020.CSV
doInputfromCmaq=0
baselineModelDataFile=C:\Users\ Documents\My SMAT-CE Files\Result\CSV\ClarkCo_O3SIP\ camxv720_cb6r5.May-
Aug.12US2.35.clark.sns6.MDA8.4km.SMAT.csv
forecastModelDataFile=C:\Users\ Documents\My SMAT-CE Files\Result\CSV\ClarkCo_O3SIP\ camxv720_cb6r5.May-
Aug.12US2.35.clark.fy2023.MDA8.4km.SMAT.csv
temporalAdjustmentAtMonitorGrid=3x3
temporalAdjustmentType=Maximum-paired in space
ozoneStartYear=2014-2016
ozoneEndYear=2016-2018
minNumDV=1
requiredDVPeriods=None selected
defaultInterpolationMethod=Inverse Distance Weights
doCheckToSetMaxDistance=0
maxDistance=100
useInitialThresholdValue=0
initialThresholdValue=85
minNumofDaysAtorAboveThreshold=10
topXmodeledozonedays=10
minAllowableThresholdValue=60
minNumDaysAtorAboveMinAllowableThreshold=5
doBackstop=0
backstopMinThresholdforSpatialField=0
subrangeFirstDay=1
subrangeLastDay=123
doPairDays=0
SRF_StartValue=1
SRF_EndValue=5
```

Figure 9-1. SMAT-CE settings applied for the 2023 future base DV projections.

9.3.4 Results at Monitoring Sites

Table 9-2 shows base and projected DV results. According to SMAT-CE, no exceedances were projected in 2023 based on the 2023 future base CAMx simulation. The peak average projected DV was 69 ppb at Joe Neal.

Figure 8-34 shows the spatial distribution of monitored 2020 DVs reported at sites within and immediately surrounding the CCNAA. Four sites within Las Vegas and near Henderson exceeded the 2015 ozone NAAQS, as shown in dark blue (Joe Neal, 74 ppb; Walter Johnson, 73 ppb; Paul Meyer, 73 ppb, Green Valley, 72 ppb). These 4 sites resulted in the bump-up from Marginal to Moderate nonattainment in 2021.

Table 9-2. 2016-2018 monitored and 2023 projected DVs at each monitoring site within the LVV according to SMAT-CE calculations using the 2016 base and 2023 future base CAMx simulations. Red values indicate exceedances of the 2015 ozone NAAQS, green indicate values below the NAAQS. Sites noted with an asterisk continued to exceed the ozone NAAQS in 2020, leading to the bump up from Marginal to Moderate nonattainment status (Figure 8-34).

Site ID	Site Name	2016-2018 DV Avg 3x3	2023 DV Avg 3x3
320030022	Apex	70.3	65.2
320030023	Mesquite	61.3	57.2
320030043	Paul Meyer*	72.0	67.7
320030071	Walter Johnson*	72.3	67.9
320030073	Palo Verde	72.3	67.2
320030075	Joe Neal*	75.0	69.0
320030298	Green Valley*	71.0	67.3
320030540	Jerome Mack	68.7	64.1
320030601	Boulder City	66.0	61.5
320031019	Jean	68.3	63.9
320032002	J.D. Smith	72.5	67.3
320037772	Indian Springs	68.5	62.3

Figure 9-2 shows a scatter plot comparing, at each monitoring site in Table 9-2, the average of modeled top 10 MDA8 ozone in 2016 as reported by SMAT-CE against the historical 2016-2018 average DV. The plot confirms that the model under predicted 2016-2018 DV levels consistently, but perhaps more importantly, the linear correlation was rather good (R^2 = 0.83). This shows that the 2016 modeled spatial patterns of high and low ozone represented the historical DV patterns well. It further adds some weight to the argument that the model adequately replicated the spatial distribution of the processes that form and disperse ozone throughout the basin, and so in turn the spatial distribution of the respective RRFs should be reasonably represented as well. Certainly, the same could not be said if the comparison in Figure 9-2 exhibited low correlation (large scatter) with high predicted ozone where low ozone was monitored and vice versa.

The amount of predicted regional ozone streaming into the CCNAA from southern California is an important component in the 2023 projection. The accuracy of the 2023 DVF projection depends in large measure on the accuracy of the regional anthropogenic emission inventory, wildfire influences, and the chemistry and dispersion/transport patterns characterized in the CAMx simulations.

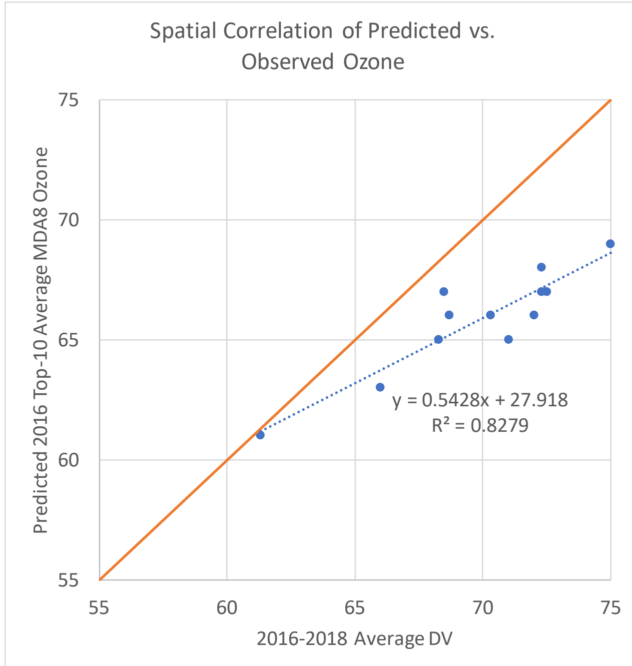


Figure 9-2. Comparison at each monitoring site (blue dots) between the average modeled top 10 MDA8 ozone in 2016 as reported by SMAT-CE and the historical 2016-2018 average DV.

10.0 FUTURE YEAR CONTROL MEASURE SIMULATIONS

This Section describes the CAMx future year control measure modeling scenarios and results from applying the modeled attainment test to project the 2016-2018 average DV to the 2023 future year. The methodology closely follows the approach described in EPA modeling guidance (EPA, 2018a) and in the Modeling Protocol developed during the early phases of this project (Ramboll, 2022a).

10.1 Summary of Results

We developed a 2023 future year emission inventory that reflects 6 control measures representing the CCNAA 15% VOC Rate of Progress (ROP) Plan as originally developed and documented by Ramboll (2023a). The control measures reduced VOC emissions only from the nonpoint solvent sector of the 2023fj platform emissions inventory. [Note that the ROP has since been substantially revised (Ramboll, 2024a,b) to reflect a different set of control measures extending to 2026 in response to discussions with EPA.]

- Projected 2023 DVs were all well below the ozone NAAQS but only 0-0.4 ppb lower than the DV projections from the 2023 future base case (Section 9). The peak average projected DV was 68.8 ppb at Joe Neal.

We developed a 2023 CCNAA future year conformity budget emission inventory that reflects an additional 2 TPD NOx and VOC margin above CCNAA 2023 base case on-road mobile source emissions (Ramboll, 2023b), as well as increased point source NOx and VOC to account for emissions currently contained within Clark County Emissions Reduction Credit (ERC) program.

- Projected 2023 DVs were all well below the ozone NAAQS and 0-0.3 ppb higher than the DV projections from the 2023 future base case. The peak projected DV was 69.3 ppb at Joe Neal.

10.2 15% VOC Rate of Progress Plan

Clean Air Act Section 182(b)(1) requires moderate ozone nonattainment areas to reduce VOC emissions by 15% over 6 years following the baseline year (2017 in the case of the CCNAA). This requirement is known as the Rate of Progress (ROP) plan. Ramboll (2023a) developed a technical support document that identified and quantified several control measures that, along with specific Reasonably Available Control Technology (RACT) measures developed by the DES/DAQ, would achieve a 15% VOC reduction relative to the 2017 CCNAA emission inventory.

10.2.1 Control Measures

Table 10-1 is repeated from Ramboll (2023a) and presents the 2017 baseline and 2023 future year CCNAA emission inventories, estimated 2023 emission reductions for each RACT and planned local control measure, and net total 2023 emissions and reductions. Net emission reductions from 2017 to 2023 are 19.53 TPD or 18.1%, indicating that the 15% ROP requirement can be met through the implementation of the RACT and planned local control measures. [Note that the ROP has since been substantially revised (Ramboll, 2024a,b) to reflect a different set of control measures extending to 2026 in response to discussions with EPA.]

Table 10-1. CCNAA 2017 and 2023 VOC emissions (TPD) by sector, emission reductions by control measure, and net change in CCNAA emissions from 2017 to 2023 for the 15% ROP scenario as documented by Ramboll (2023a).

Description	2017	2023	Difference	Percent Difference
VOC Emissions by Sector				
Point source	1.25	1.32	0.07	5.6%
Nonpoint source	56.05	58.29	2.24	4.0%
Onroad mobile	24.43	17.01	-7.42	-30.4%
Nonroad mobile	24.03	24.17	0.14	0.6%
Airports (commercial & Federal)	1.94	2.62	0.68	35.1%
Locomotives	0.04	0.03	-0.01	-25.0%
Subtotals	107.73	103.44	-4.29	-4.0%
RACT VOC Emission Reductions				
Solvent Metal Cleaning (Degreasers)		0.66		
Graphic Arts		1.43		
Cutback Asphalt		0.78		
Industrial Cleaning Solvents		2.82		
Subtotals		5.69		
VOC Emission Reductions for Planned Local Control Measures				
Consumer Products OTC Model Rules Phase IV		6.74		
AIM Coatings OTC Model Rules Phase II		2.70		
Subtotals		9.44		
Net VOC Emissions				
Totals	107.73	88.31	-19.42	-18.0%

10.2.2 Emissions Processing

We prepared SMOKE control packets for each control measure listed in Table 10-1. The control packets specify control factors at the source category code (SCC) level, as shown in Table 10-2. The control factors were applied to 2023fj Clark County inventories from the 2016v2 Modeling Platform (EPA, 2022b) to develop emissions for the 15% ROP control scenario. Both RACT and planned local control measures reduced VOC emissions only from the nonpoint solvent sector of the 2023fj platform emissions inventory.

The RACT measures were applied only to the CCNAA, while the two planned local control measures (AIM coatings and Consumer products) were applied to the whole county. To develop CAMx-ready emissions, we created an adjusted emission inventory by applying SCC-level control factors from the SMOKE control packets and processed resulting emissions through SMOKE. First, the adjusted emission inventory with VOC reductions from both the planned local control measures and RACT measures was processed through SMOKE for the CCNAA portion of Clark County (HA 212 domain). Next, the adjusted inventory with VOC reductions from just the planned local control measures was processed for the full CC4c2 modeling domain. Finally, the emissions generated for the CCNAA were merged into the CC4c2 domain to develop the final merged CAMx-ready emissions.

Table 10-2. SCC-level VOC control efficiency (%) by control measure for 15% ROP scenario.

SCC	SCC Description	VOC Control Efficiency (%)
RACT Control Measures		
Degreasing		
2460200000*	All Household Products	5.5%
2460290000*	Household Products: Miscellaneous Household Products	5.5%
Graphical Arts		
2425000000	Solvent - Graphic Arts	56.3%
Cutback Asphalt		
2461021000	Cutback Asphalt	100%
Industrial Cleaning Solvent		
2402000000	Chemical Strippers	76.0%
Planned Local Control Measures		
Consumer Products		
2460100000	Solvent - All Personal Care Products	23.9%
2460110000	Personal Care Products: Hair Care Products	23.9%
2460190000	Personal Care Products: Miscellaneous Personal Care Products	23.9%
2460200000*	All Household Products	21.3%
2460290000*	Household Products: Miscellaneous Household Products	21.3%
2460500000	All Coatings and Related Products	23.9%
2460600000	All Adhesives and Sealants	23.9%
2460900000	Solvent - Miscellaneous Products (Not Otherwise Covered)	23.9%
Architectural and Industrial Maintenance (AIM) Coatings		
2401001000	Architectural Coatings	40.7%
2401100000	Industrial Maintenance Coatings	40.7%

* Control measures are additive when the same SCC is controlled by more than one control measure.

Table 10-3 summarizes the 2023 VOC emissions by SCC before and after applying control measures selected for the 15% ROP scenario. The comparison of VOC control efficiency for each SCC in Table 10-2 and the corresponding percent reduction in Table 10-3 confirm that the control factors were applied correctly during emission processing to produce CAMx-ready emissions for the 15% ROP control scenario.

Table 10-3. Annual VOC emissions inventory before and after applying control factors.

SCC	SCC Desc	2023 VOC Emissions (TPY)	VOC Emissions with 15% ROP Controls (TPY)	Difference (%)
2461021000	Cutback Asphalt	303	0	100%
2460200000	All Household Products	456	334	27%
2460290000	Household Products: Miscellaneous Household Products	3,995	2,924	27%
2460110000	Personal Care Products: Hair Care Products	4,076	3,102	24%
2460190000	Personal Care Products: Miscellaneous Personal Care Products	118	90	24%
2460600000	All Adhesives and Sealants	1,742	1,325	24%
2401001000	Architectural Coatings	1,683	998	41%
2460500000	All Coatings and Related Products	524	399	24%
2402000000	Chemical Strippers	1,359	326	76%
2401100000	Industrial Maintenance Coatings	826	490	41%
2425000000	Solvent - Graphic Arts	934	408	56%
2460900000	Solvent - Miscellaneous Products (Not Otherwise Covered)	44	33	24%
2460100000	Solvent - All Personal Care Products	52	40	24%
Total		16,112	10,469	35%

Table 10-4 summarizes the model-ready VOC emissions over the entirety of Clark County by major anthropogenic categories for the 2023 future base case and 15% ROP scenarios. As noted previously, the 15% ROP control scenario only affects the solvent sector of the nonpoint source category. Figure 10-1 shows the spatial distribution of May-August average day 2023 VOC emissions and differences when the 15% ROP reductions are applied. The reductions occur mostly over the CCNAA with the largest average reduction of 0.31 tons/day.

Table 10-4. July weekday average 2023 future base case and 2023 15% ROP emissions (TPD) over the entirety of Clark County by major source category.

Source Category	2023 VOC	2023 15% ROP
Point source	1.8	1.8
Nonpoint source	60.8	50.9
On-road mobile	17.7	17.7
Non-road mobile	27.6	27.6
Airports (commercial & Federal)	3.1	3.1
Locomotives	0.0	0.0
Fires	0.3	0.3
TOTAL	111.3	101.4

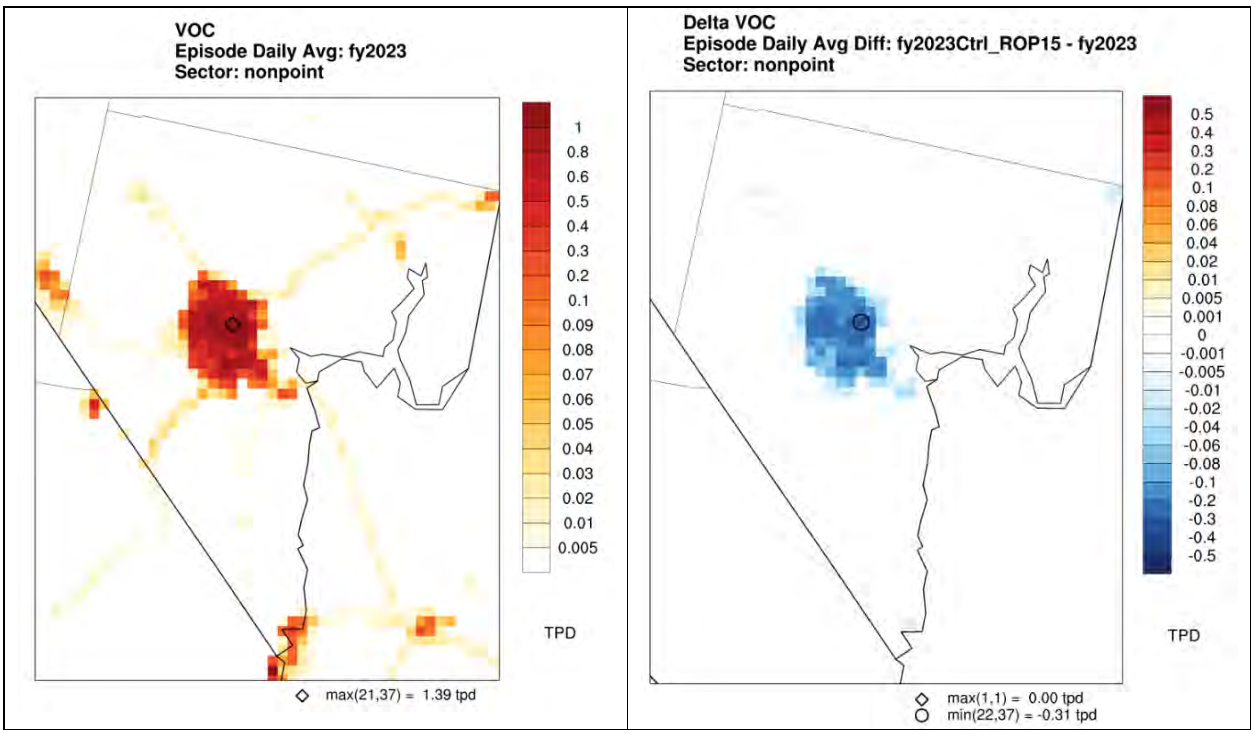


Figure 10-1. Spatial map of May-August average daily VOC emissions (TPD) for the nonpoint source category over the CC4c2 grid; 2023 future base case (left) and differences when 15% ROP reductions are applied.

10.2.3 CAMx Modeling

The 2023 future year base case CAMx run (Section 5) was repeated but replacing 2023 solvent sector emissions on the CC4c2 grid with revised emissions reflecting 15% VOC ROP control measures as described above. All other inputs were not modified (Table 10-5), and only the 12US2/CC4c2 2-way nested grids were run using the 2023 12US2 future base case boundary conditions extracted from the 36US3 grid.

10.2.3.1 SMAT-CE Configuration

We applied SMAT-CE identically to the original 2023 future base case scenario, specifying 2016-2018 3-year DV period for base monitored ozone (2014-2018 4th highs centered on 2016). All other configuration options remained the same as the original SMAT-CE run, which employed default or standard settings throughout the setup menu. We made no special modifications to monitored data or specific selection of modeled days for the RRF calculation.

10.2.3.2 Results at Monitoring Sites

Table 10-6 shows projected DV results at monitoring sites that reported sufficient data during the 2016-2018 base year DV period. Projected DVs were all well below the ozone NAAQS but only 0-0.4 ppb lower than the DV projections from the 2023 future base case. This is a relatively small decrease given 18% reductions in CCNAA VOC emissions relative to the 2023 future base case. The peak average projected DV was 68.8 ppb at Joe Neal.

Table 10-5. CAMx model configuration for the CCNAA 2023 15% VOC ROP scenario. Changes from the 2023 future base case are noted in red.

Model Component	CCNAA Application	Comment
Model Code	CAMx v7.20 - May 2022	
Modeling Period	May 1 – August 31, 2016	
Horizontal Grids		
Map Projection	Lambert Conic Conformal	EPA 2016 MP
36 km (36US3)	172 x 148 cells	Not run
12 km (12US2)	396 x 246 cells (no buffer cells)	EPA 2016 MP (2-way nesting)
4 km (CC4c2)	50 x 62 cells (with buffer cells)	CCNAA grid (2-way nesting)
Vertical Grid	35 layers	EPA 2016 MP, defined by WRF
Initial Conditions	12US2/CC4c2 IC May 1 from 36US3	2023 future year base case
Boundary Conditions	12US2 BC from 36US3	2023 future year base case
Time Zone	UTC	EPA 2016 MP
Emissions		
36/12 km Data Sources	EPA 2023fj from 2016v2 MP	
4 km Data Sources	EPA 2023fj from 2016v2 MP + 2023 Clark County Data, elevated Reid LTO emissions	15% VOC ROP reductions applied to solvent sector
Models/Processing Tools	SMOKE, MOVES3, SMOKE-MOVES, BEIS4/BELD6	CCNAA grid
Plume-in-Grid	Off	No large point sources in high-resolution CCNAA grid
In-line Ix emissions	On	Oceanic halogens
Chemistry		
Gas Phase Chemistry	CB6r5	Latest mechanism available
Aerosol Chemistry	Active	Gas phase only
Meteorological Interface	WRFCAMx v5.2	
Horizontal Diffusion	Smagorinsky	Spatially variant K-theory
Vertical Diffusion	YSU Kv formulation + KVPATCH	Minimum Kv 0.1 to 1.0 m^2/s
ACM2	Off	Non-local boundary layer convection
Sub-grid Cloud Convection	Off	
Deposition		
Dry Deposition	Zhang03	
Wet Deposition	On	rain/snow/graupel
Surface Chemistry Model	Off	
Bi-directional Ammonia	Off	For aerosol chemistry
Numeric Solvers		
Gas Phase Solver	Euler Backward Iterative (EBI)	Default fast and accurate solver
Vertical Advection	Piecewise Parabolic Method (PPM)	Default
Horizontal Advection	Piecewise Parabolic Method (PPM)	Default
Integration Time Step	Wind speed dependent	~0.5-1 min (4 km), 1-5 min (12 km), 5-15 min (36 km)
Super Stepping	On	Maximizes time step selection

Table 10-6. 2023 projected DVs at each monitoring site within the LVV according to SMAT-CE calculations using the 2016-2018 average base year DVs. Projected DVs are listed for the original 2023 future base case and for the 2023 15% VOC ROP scenario. Green indicates values below the NAAQS while sites noted with an asterisk continued to exceed the ozone NAAQS in 2020, leading to the bump up from Marginal to Moderate nonattainment status.

Site ID	Site Name	2023 Future Base DV Avg 3x3	2023 15% VOC ROP Avg 3x3	Differences Avg
320030022	Apex	65.2	65.2	0.0
320030023	Mesquite	57.2	57.2	0.0
320030043	Paul Meyer*	67.7	67.5	-0.2
320030071	Walter Johnson*	67.9	67.5	-0.4
320030073	Palo Verde	67.2	66.9	-0.3
320030075	Joe Neal*	69.0	68.8	-0.2
320030298	Green Valley*	67.3	67.1	-0.2
320030540	Jerome Mack	64.1	64.0	-0.1
320030601	Boulder City	61.5	61.5	0.0
320031019	Jean	63.9	63.9	0.0
320032002	J.D. Smith	67.3	67.1	-0.2
320037772	Indian Springs	62.3	62.2	-0.1

10.3 Conformity Budget

Working from the 2023 CCNAA base year emission inventory (Ramboll, 2023b), the DES/DAQ defined the 2023 CCNAA conformity budget to include: (1) a safety margin for the on-road mobile sector, and (2) all banked stationary source ERC. Modeling using the 2023 base year inventory demonstrated attainment of the ozone NAAQS (Section 9) without additional reductions associated with the 15% VOC Rate of Progress (ROP) Plan (Section 10.2). Therefore, the 2023 conformity budget builds from the 2023 base year inventory. Specifically, the 2023 conformity budget adds 2 TPD of both NOx and VOC to on-road mobile source emissions within the CCNAA, and adds current ERC NOx and VOC to point source emissions within the CCNAA. Tables 10-7 and 10-8 summarize the 2023 CCNAA VOC and NOx emission inventories, respectively, for the 2023 base and conformity scenarios.

Table 10-7. 2023 CCNAA base and conformity VOC emission inventories.

Source Category	2023 Base (TPD)	2023 Conformity (TPD)	Change (TPD)	Change (%)
Point source	1.32	1.37	0.05	3.8%
Nonpoint source	58.29	58.29		
On-road mobile	17.01	19.01	2.00	11.8%
Non-road mobile	24.17	24.17		
Airports (commercial & Federal)	2.62	2.62		
Locomotives	0.03	0.03		
ERC	0.05	0.00	-0.05	-100%
Total	103.49	105.49	2.00	1.9%

Table 10-8. 2023 CCNAA base and conformity NOx emission inventories.

Source Category	2023 Base (TPD)	2023 Conformity (TPD)	Change (TPD)	Change (%)
Point source	3.23	4.15	0.92	27.6%
Nonpoint source	4.01	4.01		
On-road mobile	19.15	21.15	2.00	10.4%
Non-road mobile	22.98	22.98		
Airports (commercial & Federal)	15.52	15.52		
Locomotives	0.66	0.66		
ERC	0.92	0.00	-0.92	-100%
Total	66.47	68.47	2.00	3.0%

The CCNAA emission inventories in Tables 10-7 and 10-8 reflect typical July weekday conditions consistent with the emissions budget reported in the SIP Inventory report (Ramboll, 2023b). To transfer this information to CAMx-ready hourly May-August emission inputs over the CC4c2 grid, it was necessary to adjust the 2023 base year model-ready on-road and point source emission files in a manner that faithfully replicates the incremental NOx and VOC changes noted in the tables above. This was done by developing and applying scaling factors to all NOx and VOC species for all point sources and all on-road sources within the grid cells covering only the CCNAA.

We developed a grid cell mask defining the CCNAA domain for emissions processing, which comprises a sub-set of 4 km grid cells covering the CCNAA with some overlap. We then summed emissions over that area and developed a single set of seasonal scaling factors for on-road and point sources. For on-road sources, the scaling factor was based on May-August average emissions to account for meteorological variations throughout the summer. For point sources, the scaling factor was based on July weekday average emissions to yield the respective NOx and VOC TPD increases defined in Tables 10-7 and 10-8. Note that this approach resulted in applying ERC increments to all point sources located within the CCNAA domain relative to their respective individual emission rates (i.e., sources with higher emission rates received a larger fraction of the ERC credit total). Scaling was applied to all point sources within two groups of model-ready files: electric generating units (EGU or IPM) and all others (non-IPM). As a quality assurance step, resulting on-road and point source emissions were plotted to review the spatial differences between the 2023 base and conformity input files. We confirmed that NOx and VOC emissions were increased only within the CCNA portion of the CC4c2 modeling grid. Base and conformity model-ready emissions were then summed over the CCNAA and averaged over July weekdays to ensure absolute average increases in on-road and point source sectors were consistent with the CCNAA inventory increments (Tables 10-9 and 10-10).

Table 10-9. 2023 CCNAA model-ready July weekday average base and conformity VOC emissions (TPD).

Source Category	2023 Base	2023 Conformity	Change	Change (%)
Point source	0.58	0.63	0.05	8.7%
On-road mobile	16.21	18.50	2.29	14.1%

Table 10-10. 2023 CCNAA model-ready July weekday average base and conformity NOx emissions.

Source Category	2023 Base	2023 Conformity	Change	Change (%)
Point source	2.85	3.77	0.92	32.3%
On-road mobile	18.60	20.87	2.27	12.2%

Note that 2023 model-ready emissions in the SMOKE CCNAA domain differ slightly from the 2023 CCNAA emission inventory in Tables 10-7 and 10-8. We attribute on-road emission differences to the use of EPA's 2023fj MOVES3 emission factors and use of hourly- and day-specific meteorology to estimate gridded emission rates. The additional on-road emissions for conformity are slightly higher than 2 TPD due to the application of scaling factors based on May-August average emissions. Point source emission differences from Tables 10-7 and 10-8 result from the use of EPA's 2023fj Clark County point source emissions for modeling.

10.3.1 CAMx Modeling

The 2023 future year base case CAMx run (Section 9) was repeated but replacing emissions on the CC4c2 grid with the revised on-road and point emissions described above. All other inputs were not modified (Table 10-11), and only the 12US2/CC4c2 2-way nested grids were run using the 2023 12US2 future base case boundary conditions extracted from the 36US3 grid.

Table 10-11. CAMx model configuration for the CCNAA 2023 conformity emissions budget scenario. Changes from the 2023 future base case are noted in red.

Model Component	CCNAA Application	Comment
Model Code	CAMx v7.20 - May 2022	
Modeling Period	May 1 – August 31, 2016	
Horizontal Grids		
Map Projection	Lambert Conic Conformal	EPA 2016 MP
36 km (36US3)	172 x 148 cells	Not run
12 km (12US2)	396 x 246 cells (no buffer cells)	EPA 2016 MP (2-way nesting)
4 km (CC4c2)	50 x 62 cells (with buffer cells)	CCNAA grid (2-way nesting)
Vertical Grid	35 layers	EPA 2016 MP, defined by WRF
Initial Conditions	12US2/CC4c2 IC May 1 from 36US3	2023 future year base case
Boundary Conditions	12US2 BC from 36US3	2023 future year base case
Time Zone	UTC	EPA 2016 MP
Emissions		
36/12 km Data Sources	EPA 2023fj from 2016v2 MP	
4 km Data Sources	EPA 2023fj from 2016v2 MP + 2023 Clark County Data, elevated Reid LTO emissions	2 TPD NOx and VOC margins added to the on-road sector, ERC NOx and VOC added to point sources
Models/Processing Tools	SMOKE, MOVES3, SMOKE-MOVES, BEIS4/BELD6	CCNAA grid
Plume-in-Grid	Off	No large point sources in high-resolution CCNAA grid
In-line Ix emissions	On	Oceanic halogens
Chemistry		
Gas Phase Chemistry	CB6r5	Latest mechanism available
Aerosol Chemistry	Active	Gas phase only
Meteorological Interface	WRFCAMx v5.2	
Horizontal Diffusion	Smagorinsky	Spatially variant K-theory
Vertical Diffusion	YSU Kv formulation + KVPATCH	Minimum Kv 0.1 to 1.0 m^2/s
ACM2	Off	Non-local boundary layer convection
Sub-grid Cloud Convection	Off	
Deposition		
Dry Deposition	Zhang03	
Wet Deposition	On	rain/snow/graupel
Surface Chemistry Model	Off	
Bi-directional Ammonia	Off	For aerosol chemistry
Numeric Solvers		
Gas Phase Solver	Euler Backward Iterative (EBI)	Default fast and accurate solver
Vertical Advection	Piecewise Parabolic Method (PPM)	Default
Horizontal Advection	Piecewise Parabolic Method (PPM)	Default
Integration Time Step	Wind speed dependent	~0.5-1 min (4 km), 1-5 min (12 km), 5-15 min (36 km)
Super Stepping	On	Maximizes time step selection

10.3.1.1 SMAT-CE Configuration

We applied SMAT-CE identically to the original 2023 future base case scenario, specifying 2016-2018 3-year DV period for base monitored ozone (2014-2018 4th highs centered on 2016). All other configuration options remained the same as the original SMAT-CE run, which employed default or standard settings throughout the setup menu. We made no special modifications to monitored data or specific selection of modeled days for the RRF calculation.

10.3.1.2 Results at Monitoring Sites

Table 10-12 shows projected DV results at monitoring sites that reported sufficient data during the 2016-2018 base year DV period. Projected DVs were all well below the ozone NAAQS and 0-0.3 ppb higher than the DV projections from the 2023 future base case. The peak projected DV was 69.3 ppb at Joe Neal.

Table 10-12. 2023 projected DVs at each monitoring site within the LVV according to SMAT-CE calculations using the 2016-2018 average base year DVs. Projected DVs are listed for the original 2023 future base case and for the 2023 conformity budget scenario. Green indicates values below the NAAQS while sites noted with an asterisk continued to exceed the ozone NAAQS in 2020, leading to the bump up from Marginal to Moderate nonattainment status.

Site ID	Site Name	2023 Future Base DV	2023 Conformity DV	Differences
		Avg 3x3	Avg 3x3	Avg
320030022	Apex	65.2	65.3	0.1
320030023	Mesquite	57.2	57.2	0.0
320030043	Paul Meyer*	67.7	67.8	0.1
320030071	Walter Johnson*	67.9	68.0	0.1
320030073	Palo Verde	67.2	67.3	0.1
320030075	Joe Neal*	69.0	69.3	0.3
320030298	Green Valley*	67.3	67.3	0.0
320030540	Jerome Mack	64.1	64.2	0.1
320030601	Boulder City	61.5	61.5	0.0
320031019	Jean	63.9	63.9	0.0
320032002	J.D. Smith	67.3	67.5	0.2
320037772	Indian Springs	62.3	62.5	0.2

11.0 OZONE SOURCE APPORTIONMENT

CAMx Source Apportionment (SA) was run for the 2023 future year base scenario (Section 9) to quantify and rank ozone contributions from specific source sectors and regions that contribute to high ozone in the CCNAA. This included tagging contributions from other states, international anthropogenic emissions, and regional wildfires to assess culpability of upstream and international contributions to support toward the weight of evidence (Section 12). SA also provided insights into NOx and VOC sensitivity in space and time, which can be used to assess the direction of emission reduction strategies. An initial SA design document was developed and discussed with DES/DAQ (Ramboll, 2022e) and certain configuration changes were subsequently adopted in light of technical needs and schedule constraints.

The SA configuration strikes a balance among three technical needs: (1) quantifying local source contributions among source sectors within the CCNAA; (2) quantifying upwind state and international contributions to identify states subject to Clean Air Act §110 Good Neighbor provisions and to support a possible §179B demonstration on the impacts from international anthropogenic emissions (IAE); (3) characterizing local ozone chemical regimes to determine VOC-limited versus NOx-limited conditions.

11.1 Summary of Results

- Contributions to model-projected 2023 DV at Joe Neal are consistent with EPA's two interstate source apportionment analyses.
- Natural and non-US ozone concentrations comprise the majority of ozone at 49 ppb (71% of the 69 ppb DV), California anthropogenic emissions contribute an average of 7 ppb (11%), Clark County contributes 11 ppb (16%), fires within the North American modeling domain contribute 2.4 ppb (4%), and the rest of the US contributes 1.7 ppb (3%).
- The modeled contributions to the 2023 DV at Joe Neal from all global international anthropogenic emissions are 13 ppb at Joe Neal, a value that is consistent throughout the entire inter-mountain western US and consistent with many previous studies.
- Of the total 11 ppb contributed by Clark County anthropogenic sources to the 2023 DV, non-road and onroad emissions contribute most (45% and 28%, respectively), followed by non-point area sources (9%), solvent area sources (10%), and point sources (5%).
- Of the total 7 ppb contributed by California anthropogenic sources to the 2023 DV, non-road and onroad sectors also dominate (34% each), with smaller contributions from non-point, solvent, and point sources. However, natural and fire sources contribute substantial ozone, averaging 1.4 and 2.1 ppb, respectively.
- Clark County emissions result in a relatively balanced mix of NOx and VOC sensitive ozone production over the top 10 simulated days at Joe Neal, with some substantial variations day-to-day. This is typical of a locally "transitional" regime where ozone would respond to both NOx and VOC changes.
- Spatially, ozone formation in areas outside the CCNAA is dominantly NOx-limited at nearly 100%, while ozone in the LVV represents a more balanced mix within the urban area.

11.2 CAMx Ozone Source Apportionment Tools

There are two ozone source apportionment options in CAMx:

<u>Ozone Source Apportionment Technology (OSAT)</u>: The original apportionment method uses 10 reactive tracers for each source sector/region (i), which include emitted VOC and NOx, several

intermediate NOz and odd-oxygen products that track NOx recycling, and ozone formed under VOC-limited (O3Vi) and NOx-limited (O3Ni) conditions. When an increment of ozone (ΔO3) is formed under VOC-limited conditions, the ΔO3 is allocated to the O3Vi tracers based on the relative contribution of VOC from sector/region i to total VOC. A similar approach is used to allocate ΔO3 to the O3Ni tracers under NOx-limited conditions. The ratio of the production rates of hydrogen peroxide (H_2O_2) and nitric acid (HNO_3) is the indicator used to classify ozone formation as being instantaneously limited by NOx or VOC at a particular grid cell and time. Ozone formation is classified as being NOx-limited when $P(H_2O_2)/P(HNO_3) > 0.35$ (Sillman, 1995). Thus, ΣO3Vi and ΣO3Ni over all i indicate how much ozone was formed under VOC-limited versus NOx-limited conditions, respectively, during transport to a particular grid cell.

Anthropogenic Precursor Culpability Assessment (APCA): The only difference between APCA and OSAT is the algorithm used to allocate ozone production under VOC-limited or NOx-limited conditions. APCA recognizes that certain emission sectors are not controllable (e.g., biogenic) and that apportioning ozone production to these categories does not provide information relevant to control strategies. In certain situations where OSAT would attribute ozone production to non-controllable emissions, APCA instead allocates that ozone production to the controllable precursors that participated. For example, when biogenic VOC and anthropogenic NOx form ozone under VOC-limited conditions (a situation where OSAT would attribute ozone production to biogenic VOC), APCA attributes ozone production to the anthropogenic NOx. Thus, APCA results in more ozone formation attributed to anthropogenic NOx and less ozone formation attributed to biogenic VOC. As a result, the O3Vi and O3Ni tracers may not provide reliable information on how much ozone is actually formed under VOC-limited versus NOx-limited conditions. APCA approaches the OSAT method when biogenic VOC are low (as in the CCNAA) and/or as ozone formation becomes more NOx-limited, either because of direct NOx reductions, downstream dilution of the urban plume, or in NOx-lean conditions (e.g., rural areas).

Note that neither of the options above are able to determine whether NOx disbenefits occur (i.e., when NOx emission reductions result in ozone increases). However, a large amount of VOC-limited ozone could suggest that NOx disbenefits might occur. The proper approach to analyze the possibility and magnitude of NOx disbenefits requires a sensitivity method, either by modeling a so-called “brute force” emission reduction or by employing the Decoupled Direct Method (DDM) sensitivity tool.

11.3 Identifying Key Source Regions

The selection of source regions to track in SA was guided by EPA’s interstate ozone transport analyses for the 2015 ozone NAAQS (EPA, 2022d; 2023a). EPA estimated 2023 DV contributions from individual states, biogenic emissions, fires, foreign/offshore sources, and boundary conditions (BC). We analyzed EPA’s results to determine which upwind sources have the most potential to contribute to ozone DVs in the CCNAA. As is typical for ozone, EPA found that BCs representing global background contributions from natural and IAE sources comprise the vast majority (~70%) of ozone in Clark County. California anthropogenic emissions contribute roughly the same amount of ozone as Nevada’s own contribution when averaged over CCNAA sites. Contributions from Canada and Mexico, wildfires, and biogenic emissions comprise the majority of the balance, with other States contributing fractions of one ppb (much less than 1%).

11.4 CAMx Source Apportionment Configuration

The SA application was designed to address both regional/international transport and local contributions within Clark County. The APCA method was invoked to chemically attribute NOx and VOC precursors to ozone formation. Analysis of results focused on contributions to ozone within the CCNAA. The source region and sector splits are defined below.

The 2023 SA simulation divided the 36US3/12US2/CC4c2 modeling domains into 6 source regions (Figure 11-1):

1) All of Clark County including the CCNAA
2) Remaining areas of Nevada
3) California
4) Remaining areas of the US, including the 200 mile US coastal zone
5) Mexico
6) Other international, including Canada and outside the 200 nautical mile US coastal zone

The 2023 SA simulation tracked ozone contributions from the following 7 source sectors within the 12US2/CC4c2 2-way modeling grids:

1) Natural (biogenic, lightning NOx, oceanic)
2) Open Land Fires (all wildfires, prescribed and agricultural fires)
3) On road sources
4) Non-road sources (including airports, rail, commercial marine vessels)
5) Point sources
6) Non-point solvent sector
7) Remaining non-point sectors

In the 36US3 grid, 3 source sectors were tracked along with global BCs:

1) Natural (biogenic, lightning NOx, oceanic)
2) Open Land Fires (all wildfires, prescribed and agricultural fires)
3) All anthropogenic sources

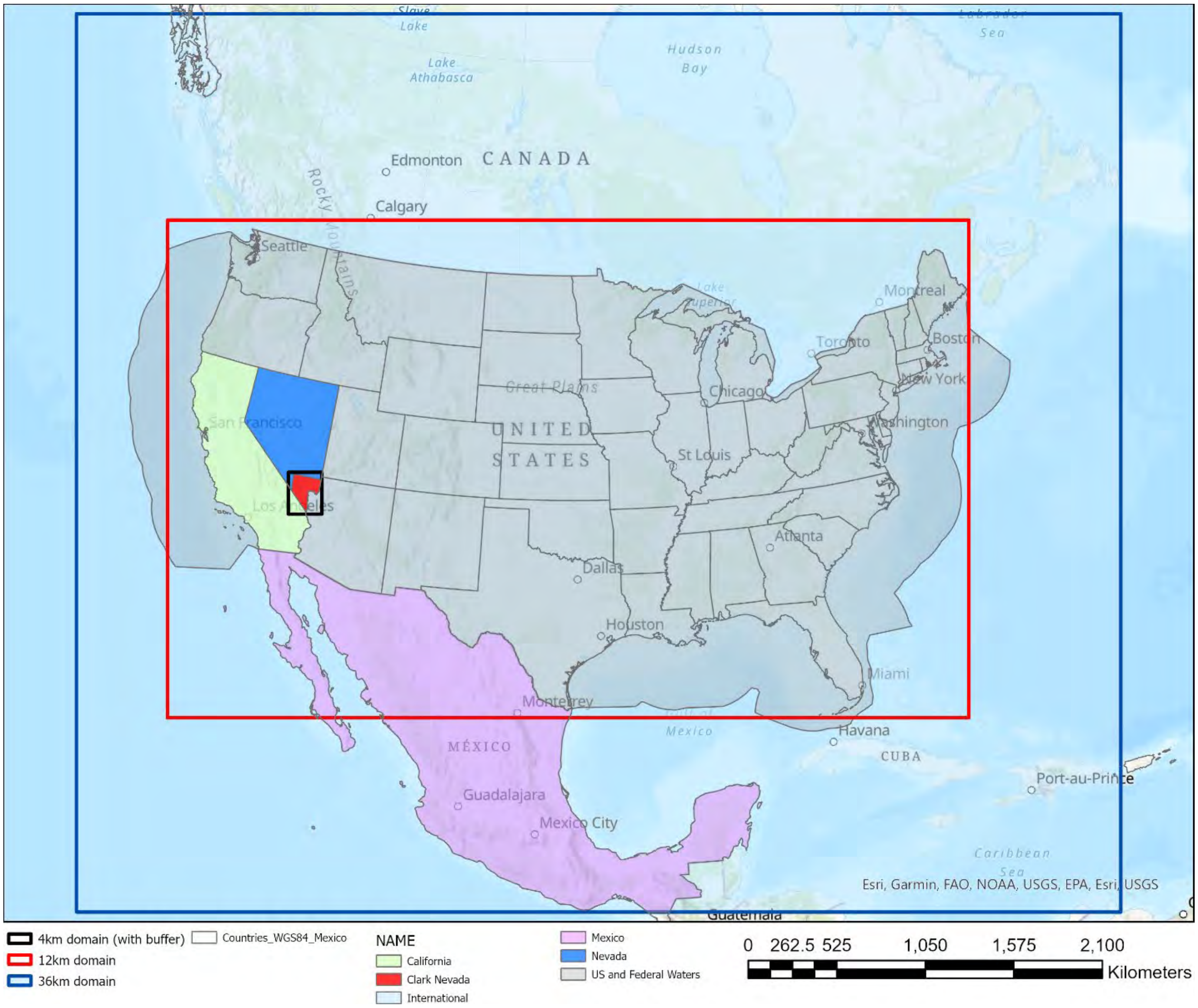


Figure 11-1. Source apportionment regions for the 2023 SA run.

Tracer concentrations for these 3 categories by 6 regions, along with a set of 2 global BCs (IAE and natural) and one set of ICs were transferred to the 12US2/CC4c2 grids via SA tracer BCs. Details are described below.

11.5 Preparing Boundary Conditions Representing International Emissions

On the 36US3 grid, SA tracked initial conditions (IC) and BC tracers. Two separate sets of BC tracers tracked global IAE and remaining natural emissions as defined by two sets of global model output. It is important that the sum of BC tracers for a given chemical species (e.g., ozone) add to the total BC concentration used for the core model at each hour and boundary grid cell to maintain consistency. The final CAMx configuration for the Clark County ozone SIP employed BCs developed from the publicly available CAM-Chem global model output datasets provided by (NCAR). CAM-Chem includes all global anthropogenic and natural precursor emissions and stratospheric ozone. Therefore, another source of global model output was needed to define the IAE contribution, which is normally determined from a “zero out rest of world” (ZROW) or natural-only scenario from the same global model. No such data were available from CAM-Chem. However, both total and ZROW scenarios were available from EPA’s 2016 H-CMAQ applications, which were developed specifically for the 2016v2 modeling platform and have pedigree of prior use for similar purposes. Specifically, H-CMAQ BCs have been used by EPA (2022d) for their preliminary interstate transport modeling, and by the State of Utah to support their §179B demonstration (UDAQ, 2021).

Under normal situations, where both total and ZROW cases are generated by a single model, we use a pre-processor that differences output concentrations from the two runs and maps those differences to two sets of BC tracers:

BC1: Total global model output

BC2: ZROW (natural-only) global model output

Tracer Group 1: BC1-BC2 = IAE (all precursors and ozone)

Tracer Group 2: BC2 = ZROW (all precursors and ozone)

In the current situation, where the total was from CAM-Chem and ZROW was from H-CMAQ, it was imperative to account for the vastly different ozone patterns generated by the two models, which we previously found to be especially apparent in the low to mid-troposphere over the eastern Pacific and western US (Section 8.4.11). Approaches to derive the IAE portion could involve either relative scaling of the CAM-Chem output or calculating absolute differences between the two models. Relative scaling was not preferred because conceptually the IAE simulated by H-CMAQ would be scaled significantly higher or lower by the vastly different ozone concentrations generated by CAM-Chem.

We considered two approaches using absolute differences. We preferred subtracting a small portion (IAE) from the total to yield ZROW, as opposed to subtracting a large portion (ZROW) from the total to yield IAE. The second approach would likely result in negative IAE values (trapped at zero) as well as frequent unrealistically large IAE values that conceivably could reach 30-40 ppb based on the differences seen between CAM-Chem and H-CMAQ ozone patterns. The first approach better constrained the IAE contribution because it was determined from the self-consistent H-CMAQ results, but it required additional pre-processing steps:

First step:

BC1: Total global model output from H-CMAQ

BC2: ZROW (natural-only) global model output from H-CMAQ

BC3: BC1-BC2 = IAE

Second step:

BC4: Total global model output from CAM-Chem

BC3: IAE (from Step 1)

Tracer Group 1: BC4-BC3 = ZROW (natural-only) CAM-Chem surrogate

Tracer Group 2: BC3 = IAE

11.6 CAMx Source Apportionment Size and Runtime

The 36US3 grid tracked 21 sets of SA tracers (3 categories x 6 regions + natural BC + IAE BC + total IC). This resulted in 210 total chemical tracers (21 x 10 ozone, precursor and intermediate species classes). Like the standard CAMx run for the 2023 future year base case, the 36US3 grid was run alone from April 1 (ICs) through August 31. SA tracer concentrations were output as 3-D arrays so that each of the 210 tracers could be passed to the 12US2/CC4c2 grid system as BCs for the separate 2-way nested SA run. This SA configuration resulted in a run time of 6 days (4% real time) and produced 3.0 TB of output. The 36US3 SA was run on 24 cores using 8 MPI nodes by 3 OMP threads on a x86_64 Intel® Xeon® ES-2690 chipset at 2.60 GHz.

The 12US2/CC4c2 grids tracked 65 sets of SA tracers (7 categories x 6 regions + 21 BC from 36US3 + top BC + IC for 12US2/CC4c2). This resulted in 650 total chemical tracers for ozone, precursor and intermediate species classes. The SA simulation for these 2-way nested grids was also run from April 1 (ICs) through August 31 in order for IC tracers among the 3 grids to be self-consistent. SA tracer concentrations were output as 2-D surface arrays. This large SA configuration resulted in a run time of 45 days (30% real time) and produced 3.3 TB of output. The 12US2/CC4c2 SA was run on 48 cores using 16 MPI nodes by 3 OMP threads on a x86_64 Intel® Xeon® ES-2690 chipset at 2.60 GHz.

11.7 2023 Ozone Source Apportionment Results

Raw hourly ozone SA tracer data were post-processed to represent contributions to total MDA8 ozone each day; i.e., the unique 8-hour period defining total MDA8 ozone at each grid cell on each day was used to time-average all ozone tracers. Results were then compiled into an Excel “dashboard” to facilitate interactive analyses in a way that maximizes choices by monitoring site, combinations of sectors, and combinations of regions. However, this dashboard combined ozone tracers generated from NOx- and VOC-sensitive chemistry to reduce the dimensionality of the dataset. A separate Excel dashboard was created to support assessment of sector-specific NOx- and VOC-sensitive chemistry. Examples of each type of plot generated by these dashboards are presented below.

Figure 11-2 presents a “landscape” time series (as a stacked area plot) of regional contributions to 2023 MDA8 ozone at the Joe Neal monitoring site over the May-August modeling period. Our analyses focus on Joe Neal as that is the controlling ozone DV monitor in the CCNAA. The contributions in Figure 11-2 start at the bottom with all global and in-domain natural sources combined, then add fires, IAE, and Mexico to yield the total uncontrollable non-US ozone concentrations. Then contributions from US, California, and Nevada anthropogenic emissions are added. Finally, Clark County anthropogenic contributions are added at the very top to yield the total MDA8 ozone at Joe Neal.

Figure 11-3 shows the global/regional contributions to the model-projected 2023 DV at Joe Neal. This is accomplished by averaging MDA8 ozone contributions at Joe Neal over the top 10 simulated days in the 2023 future base case, determining the “Relative Contribution Factors” (i.e., 10-day average percent contributions), and applying those percentages to the 2023 DV. Natural and non-US ozone concentrations comprise the majority of ozone at Joe Neal at 49 ppb (71% of the 69 ppb DV). California anthropogenic emissions contribute an average of 7 ppb (11%), while Clark County contributes 11 ppb (16%). Fires within the North American modeling domain contribute 2.4 ppb (4%), the rest of the US contributes 1.7 ppb (3%), while the rest of Nevada contributes negligibly (0.1 ppb). These results are consistent with EPA’s two interstate source apportionment analyses (EPA, 2022a,b; 2023).

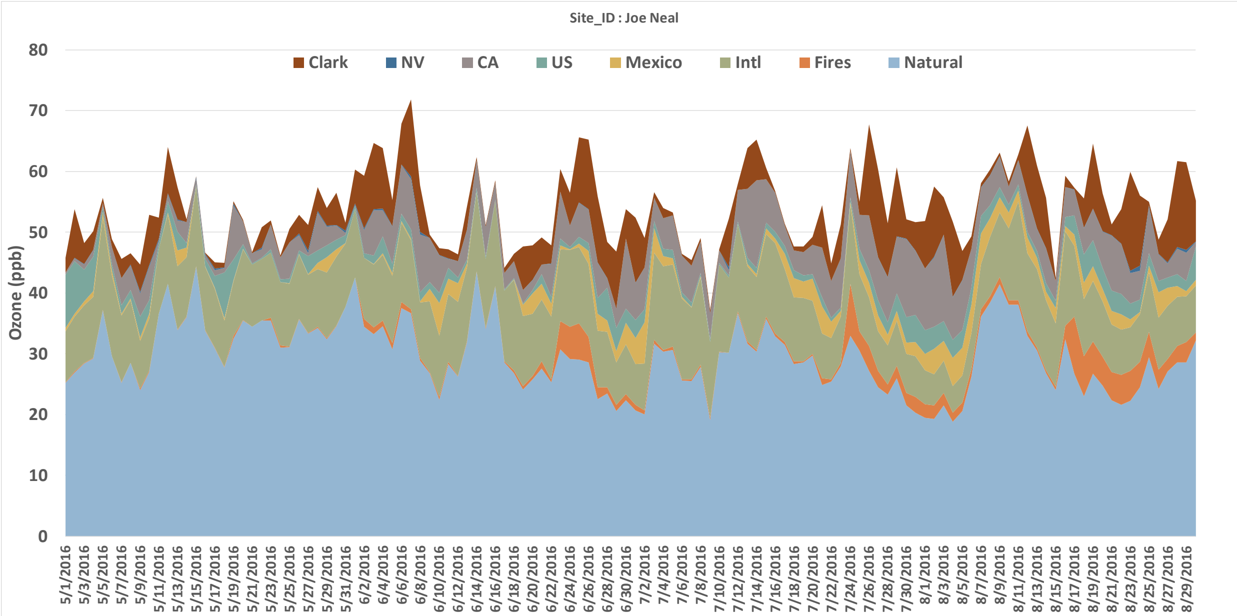


Figure 11-2. Time series of regional contributions to 2023 MDA8 ozone at Joe Neal over the May-August modeling period.

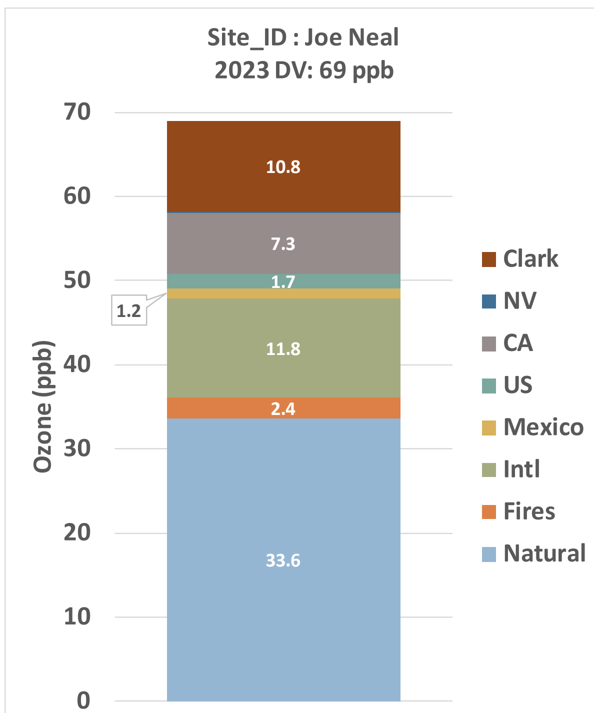


Figure 11-3. Regional contributions to the projected 2023 DV at Joe Neal.

The modeled MDA8 ozone contributions from Mexico and other IAE total 12.5 ppb at Joe Neal over the 10-day averaging period (which is scaled to 13 ppb for the 2023 DV shown in Figure 11-3). Figure 11-4 presents the spatial distribution of 10-day average modeled MDA8 ozone contributions from all IAE (including Mexico) over the entire 12US2 modeling domain. IAE contributions range 10-14 ppb throughout the entire inter-mountain western US over the averaging period, including southern Nevada. Large ozone plumes from northern Baja California and Imperial County are evident, yet the average Mexico contribution at Joe Neal over the 10 days is 1.2 ppb. Clearly, the IAE pattern over the western US is instead more consistently dominated by global anthropogenic contributions. Further, the IAE pattern in Figure 11-4 is consistent with many previous studies (e.g., EPA, 2015, 2019d; Jaffe et al., 2018; Ramboll, 2021b; Lanford et al., 2015, 2022; Zheng et al., 2020; and numerous references therein) that have shown how mountainous terrain and deep circulation patterns enhance downward mixing of mid- and upper-level tropospheric global ozone to the surface.

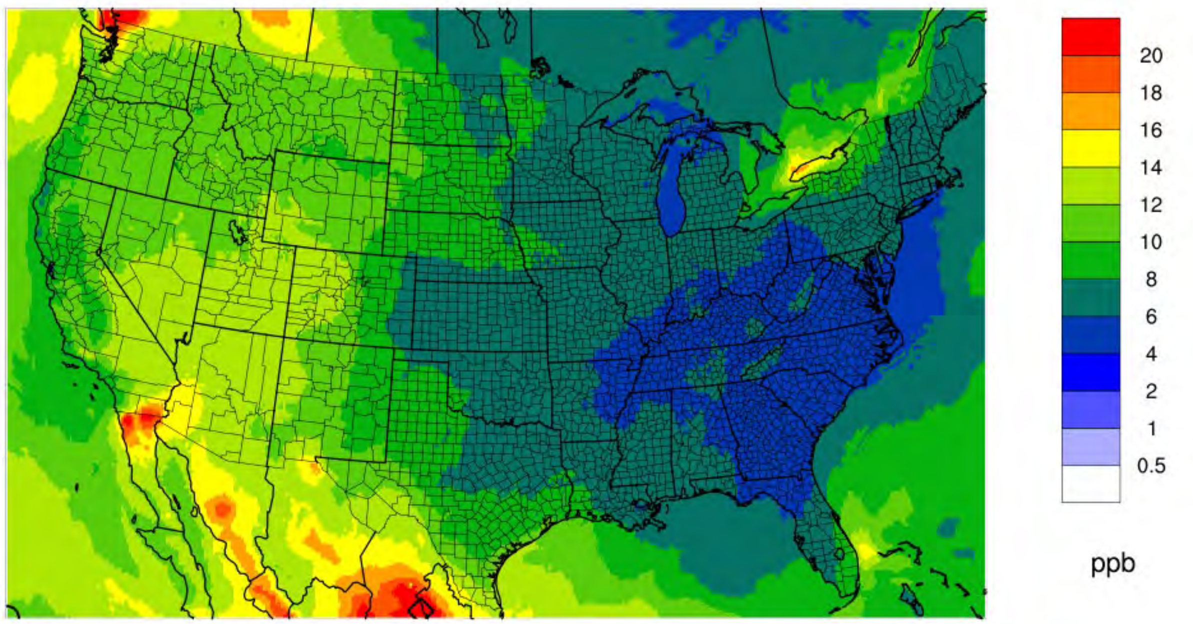


Figure 11-4. Spatial distribution of modeled MDA8 ozone contributions from all IAE (including Mexico) over the entire 12US2 modeling domain, averaged over the top 10 high ozone days at the Joe Neal monitoring site.

Figure 11-5 shows a stacked bar chart of anthropogenic source category contributions from Clark County to the 2023 DV at Joe Neal. Figure 11-6 presents similar information but for all Clark County sectors on each of the top 10 simulated days. Of the total 10.8 ppb contributed by Clark County anthropogenic sources to the 2023 DV, non-road and onroad emissions contribute most (46% and 29%, respectively), followed by non-point area sources (10%), solvent area sources (10%), and point sources (5%). Local natural sources and fires are rather minor contributors. Note that the smallest and most negligible contributor, "Anthro", represents ozone from Clark County that exited the 12US2 domain and recirculated back into Clark County (via 12US2 BCs). This tracer is necessary to account for the full apportioned mass budget across the entire 36US3 and 12US2/CC4c2 modeling domains.

Figures 11-7 and 11-8 show the same information, but for source category contributions from California. In this case, a larger mix of source sectors affects ozone in Clark County. Of the total 7.3 ppb contributed by California anthropogenic sources to the 2023 DV, non-road and onroad sectors also dominate (34% each), with smaller contributions from non-point, solvent, and point sources. However, natural and fire sources contribute substantial ozone over the top 10 simulated days, averaging 1.4 and 2.1 ppb, respectively. Note that recirculated "Anthro" from California is higher than Clark County's, but still negligible.

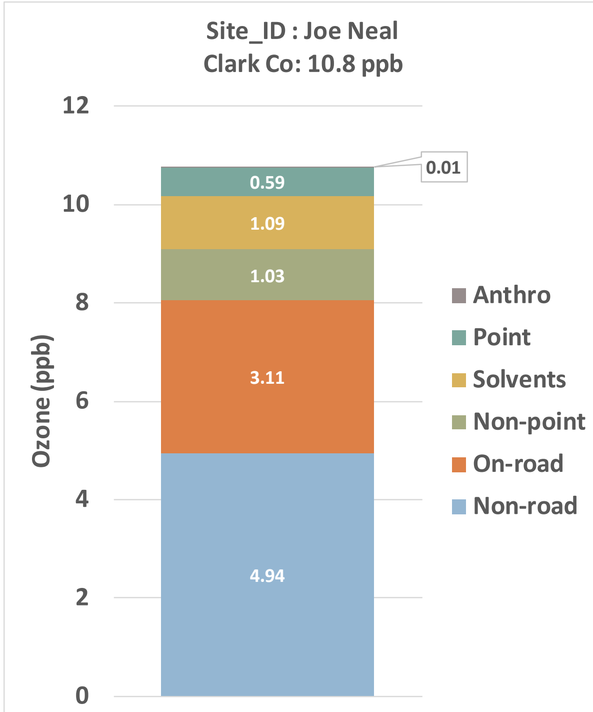


Figure 11-5. Anthropogenic source category contributions from Clark County to the 2023 DV at Joe Neal.

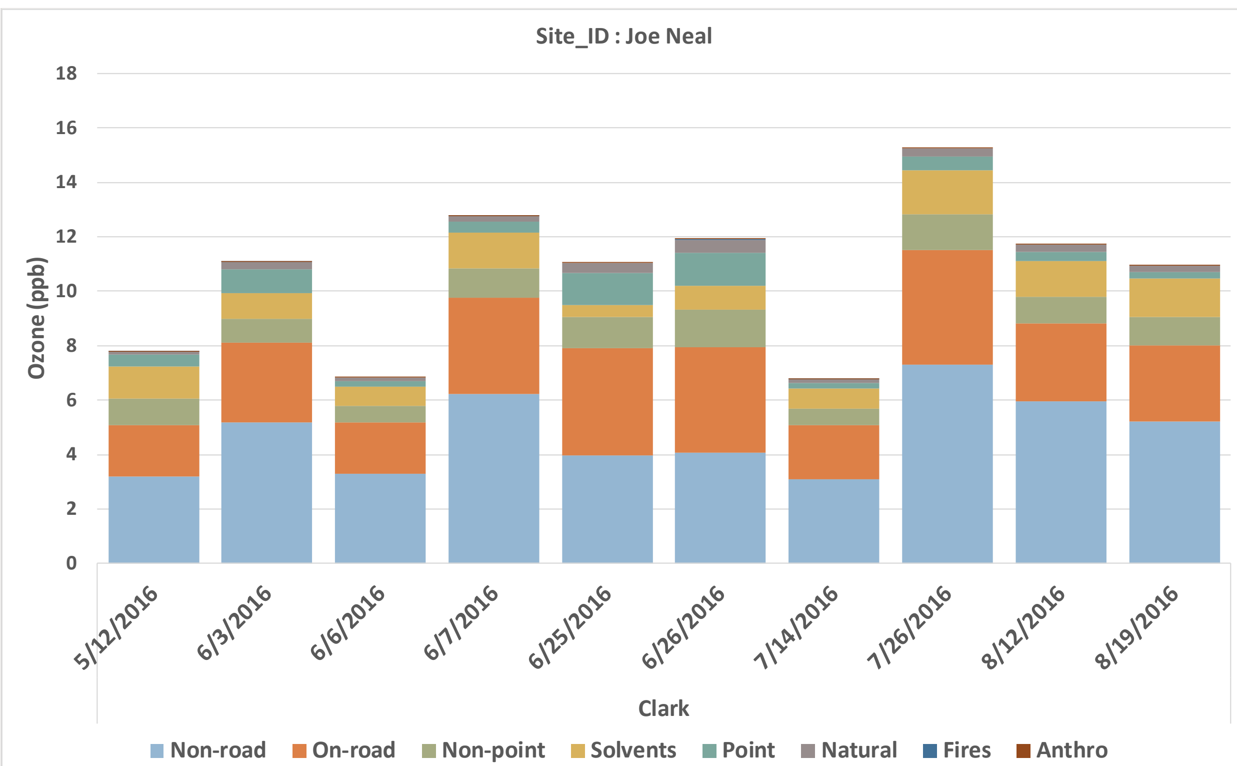


Figure 11-6. Source category contributions from Clark County to simulated MDA8 ozone at Joe Neal on each of the top 10 simulated days.

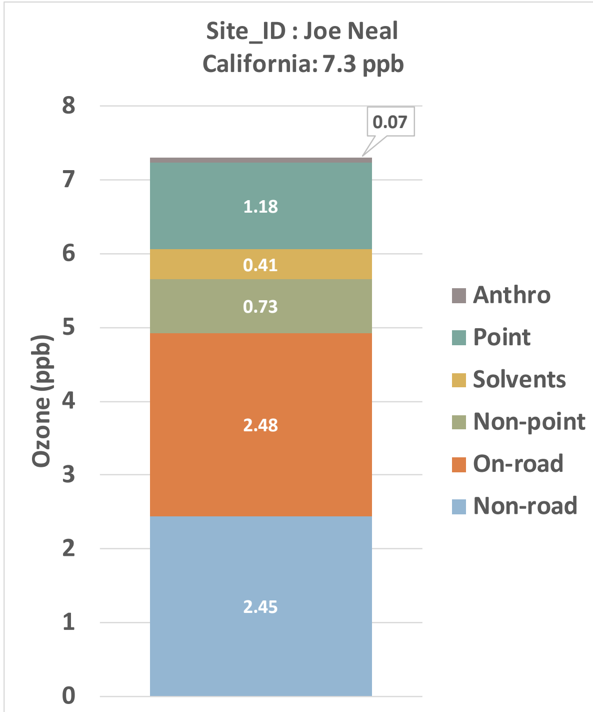


Figure 11-7. Anthropogenic source category contributions from California to the 2023 DV at Joe Neal.

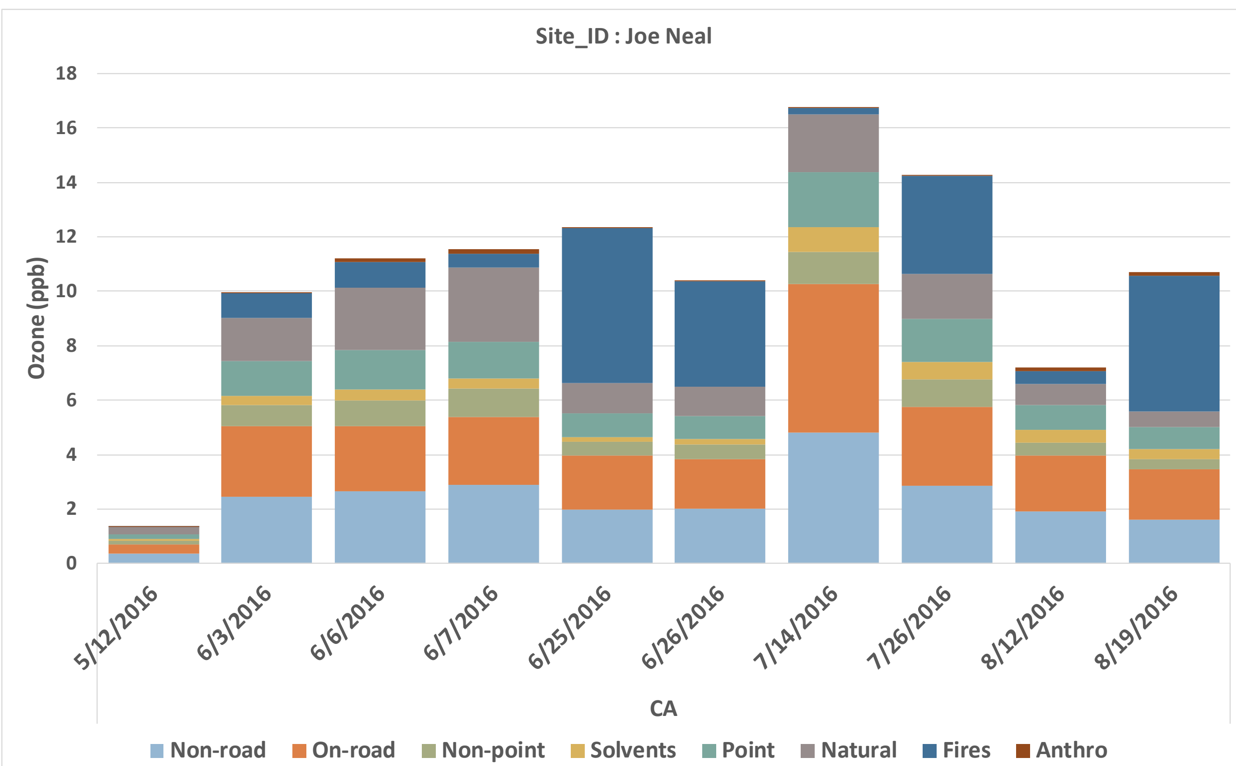


Figure 11-8. Source category contributions from California to MDA8 ozone at Joe Neal on each of the top 10 simulated days.

It is important to understand whether ozone attributed to specific sources forms via NOx-limited or VOC-limited chemistry, as that can help determine directions for control strategies. SA results can provide insights as we show below. Strictly speaking, SA is not equivalent to a "sensitivity analysis" with which to estimate effects of emission reductions on ozone concentrations. This is because ozone chemistry responds non-linearly to emission changes. Rather, SA reports an estimate of attribution under the specific environmental and emission conditions that are given to the model. When those conditions change (e.g., to simulate impacts from a control measure), attribution can change non-linearly, either positively or negatively. However, the ozone response approaches linearity with decreases in emission changes or ozone attribution.

Figures 11-9 and 11-10 present similar stacked bar plots as Figure 11-6 (Clark County contributions) and Figure 11-8 (California contributions) at Joe Neal, but for total anthropogenic emission contributions to NOx and VOC sensitive MDA8 ozone chemistry. Clark County emissions result in a relatively balanced mix of NOx and VOC sensitive ozone production over the top 10 simulated days, with some substantial variations day-to-day. This is typical of a locally "transitional" regime where ozone would respond to both NOx and VOC changes. With a dearth of biogenic VOC emissions within Clark County, the region perhaps exhibits a stronger tendency toward VOC-limited ozone production than other nonattainment areas in the western US. Conversely, ozone contributions from California are dominantly NOx-sensitive. This is likely a result of applying APCA, but is also consistent with conceptual models of ozone production from urban areas in Southern California, in which ozone production transitions from VOC-limited within the South Coast basin to NOx-limited conditions as the air mass exits the basin and crosses the Mojave Desert. Additionally, ozone from biogenic-rich rural areas in California forms in NOx-limited conditions.

Figure 11-11 shows spatial plots of NOx- and VOC-limited MDA8 ozone contributions from Clark County anthropogenic emission sectors within the CC4C2 domain. These results have been averaged over the top 10 simulated ozone days. Figure 11-11(a) includes the average total MDA8 ozone pattern for reference and shows a local ozone plume with maximum concentrations in the northwestern LVV. The other panels in Figure 11-11(a) show the 10-day average fraction of NOx- and VOC-limited ozone from Clark County anthropogenic emissions. In agreement with our conceptual model, ozone in areas outside the CCNAA is dominantly NOx-limited at nearly 100%, while ozone in the LVV represents a more balanced mix within the urban area. Average contributions from Clark County emission sectors are shown in descending order in Figure 11-11(b) through 11-11(f). The largest contribution from non-road emissions (Figure 11-11[b]) produces an ozone plume from NOx-limited chemistry in the northwest LVV, while smaller contributions from VOC-limited chemistry occur toward central Las Vegas. A similar but slightly lower contribution pattern is seen for onroad sources. Ozone generated by point sources is nearly all NOx-limited in a plume extending northeast of the LVV, which is most likely related to their emissions mix and locations relative to the urbanized area of the LVV. As expected, ozone from solvent emissions is entirely from VOC-limited chemistry in the NOx-rich central LVV. Non-point (area) sector contributions are smallest yet fairly balanced among NOx and VOC limited chemistry.

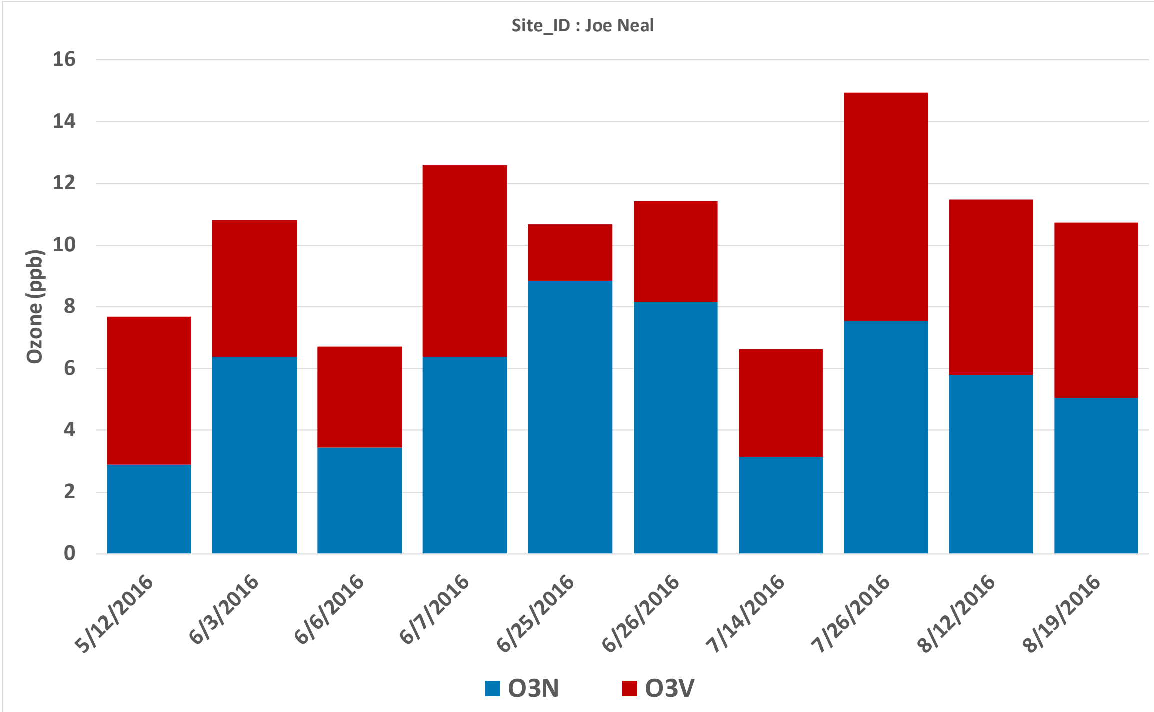


Figure 11-9. Total anthropogenic emission contributions from Clark County to NOx and VOC sensitive MDA8 ozone chemistry at Joe Neal on each of the top 10 simulated days.

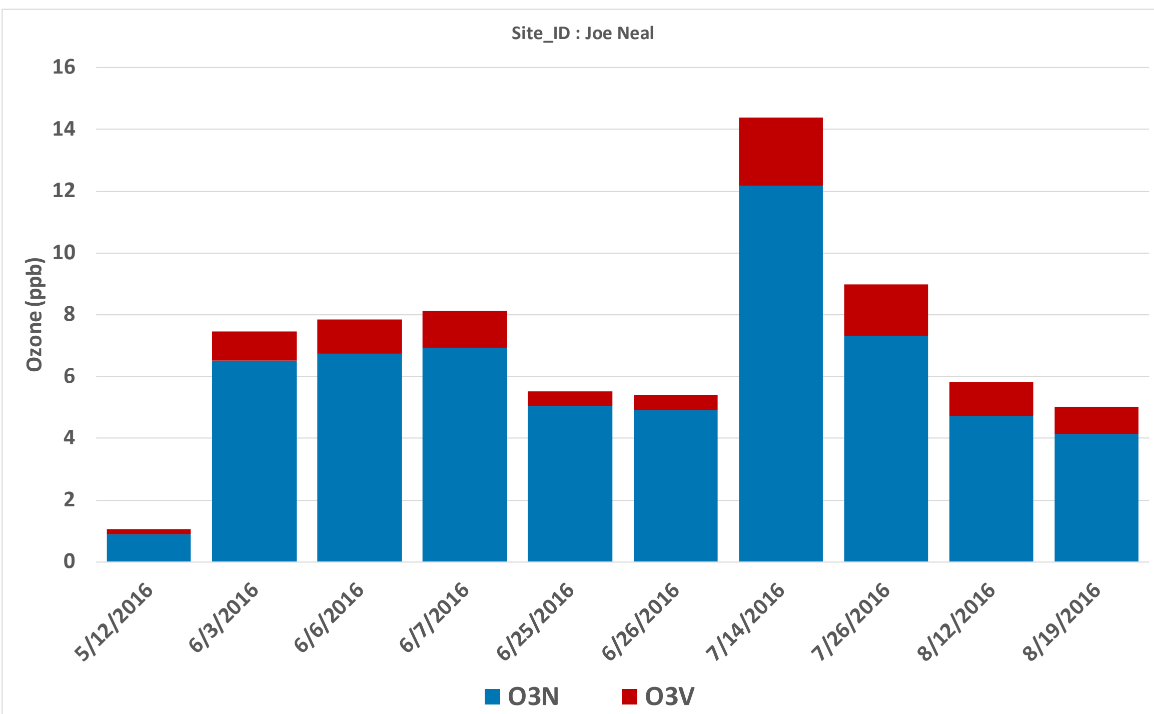


Figure 11-10. Total anthropogenic emission contributions from California to NOx and VOC sensitive MDA8 ozone chemistry at Joe Neal on each of the top 10 simulated days.

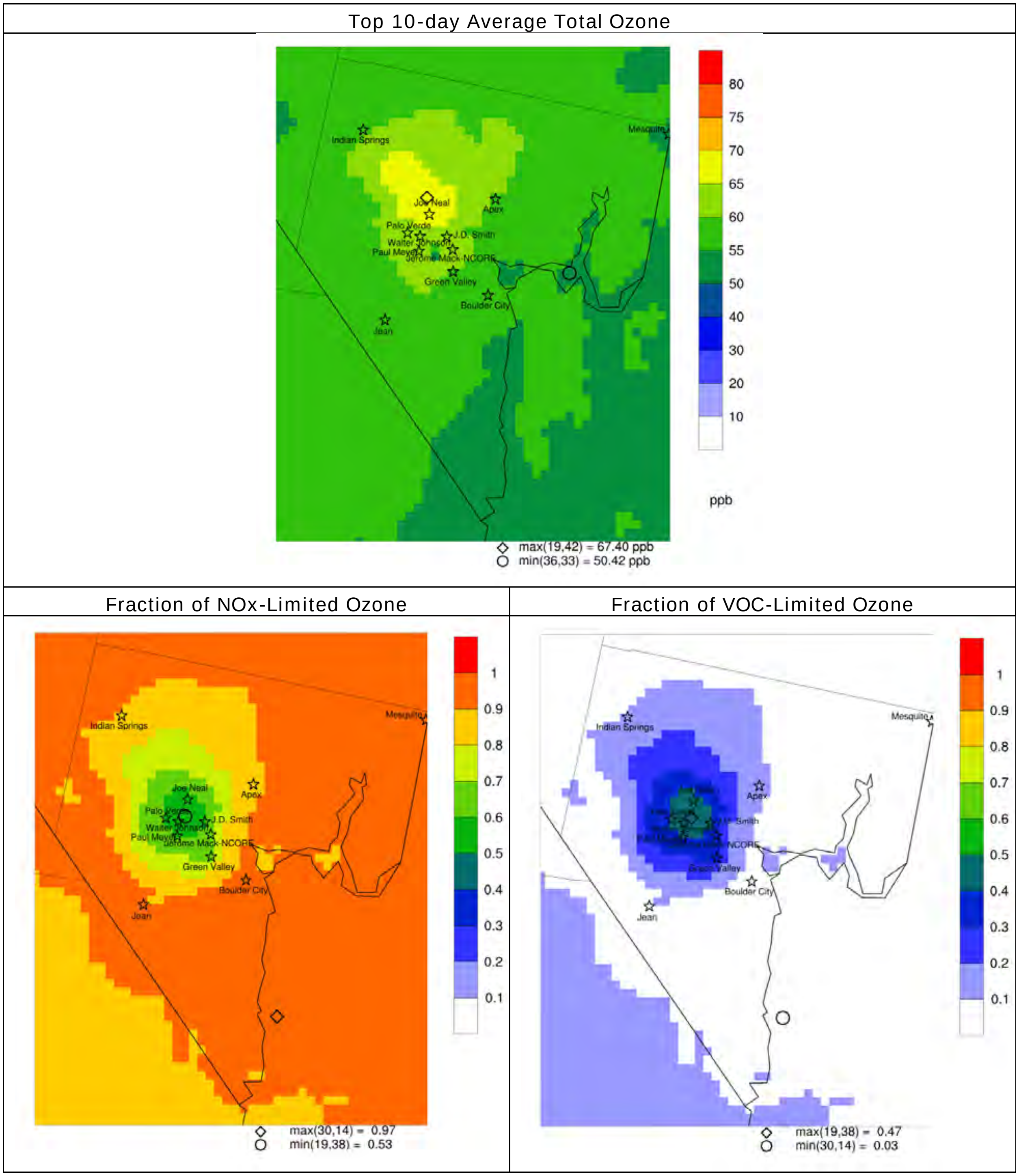


Figure 11-11(a). Top panel: total MDA8 ozone pattern within the CC4C2 domain averaged over the top 10 simulated ozone days. Bottom panels: 10-day average fraction of NOx-limited (left) and VOC-limited (right) MDA8 ozone from Clark County anthropogenic emissions.

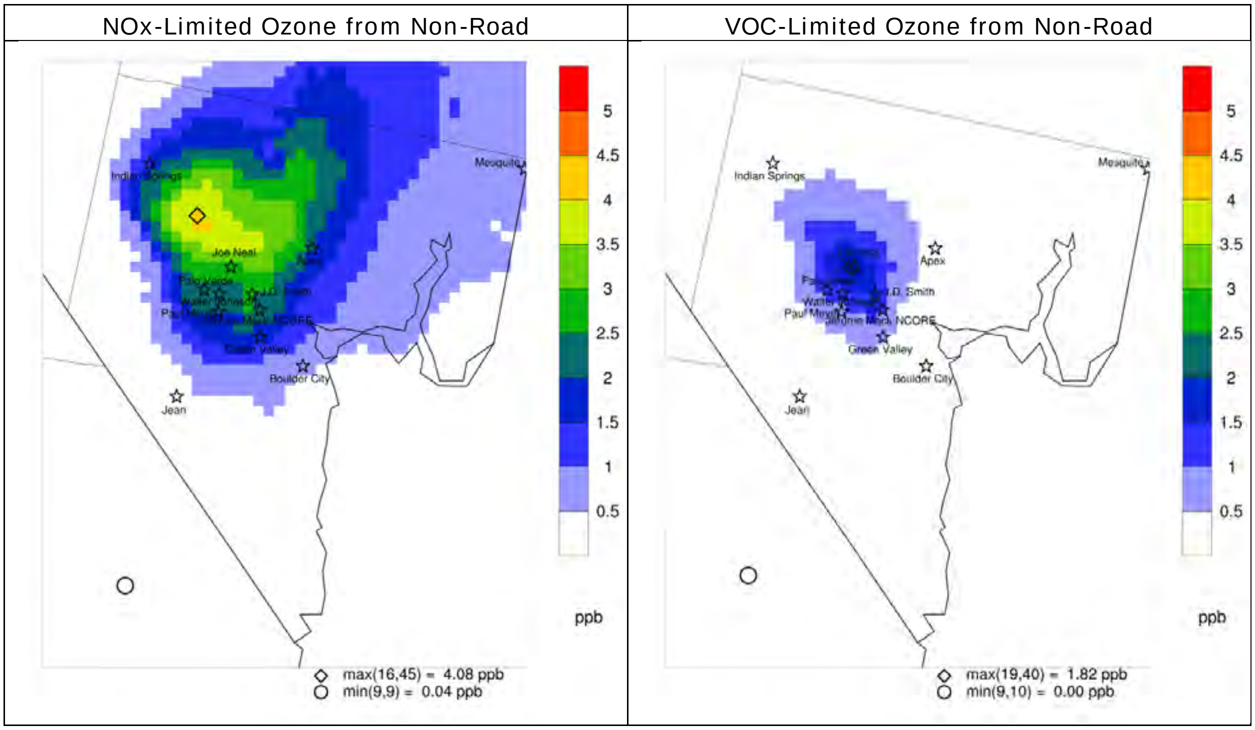


Figure 11-11(b). NOx- and VOC-limited MDA8 ozone contributions from Clark County non-road emissions averaged over the top 10 simulated ozone days.

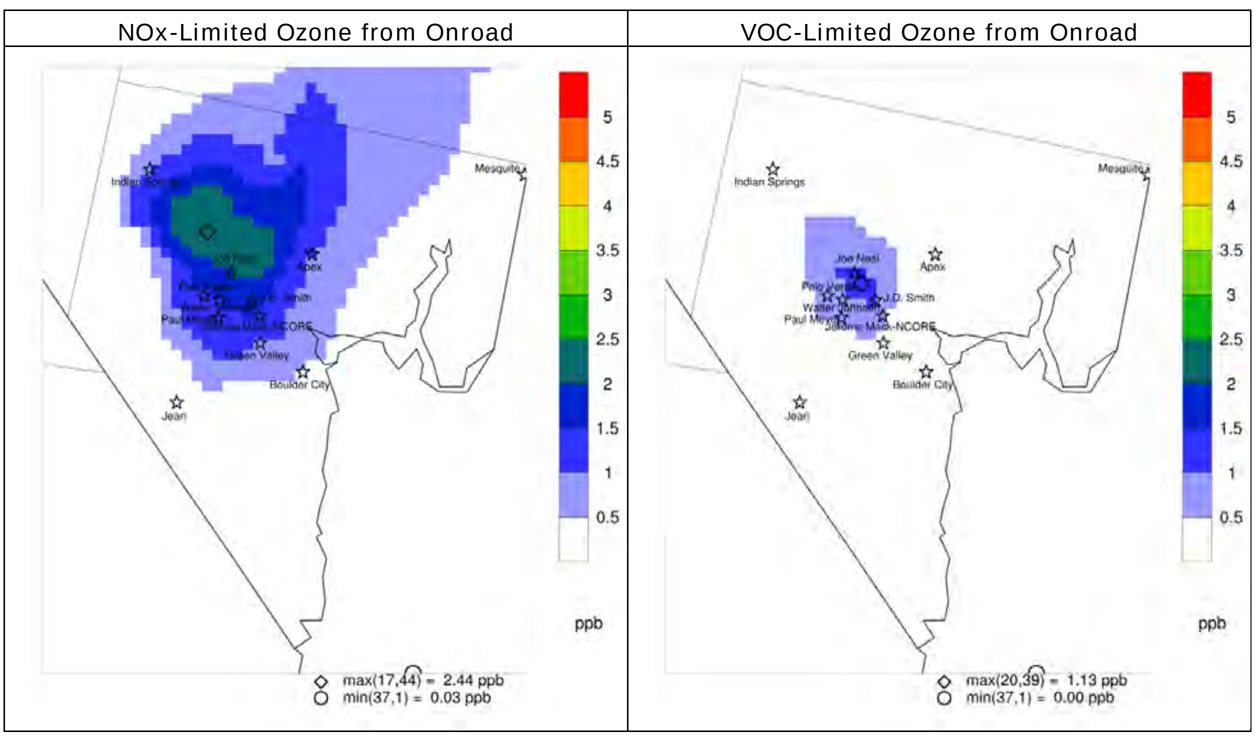


Figure 11-11(c). NOx- and VOC-limited MDA8 ozone contributions from Clark County onroad emissions averaged over the top 10 simulated ozone days.

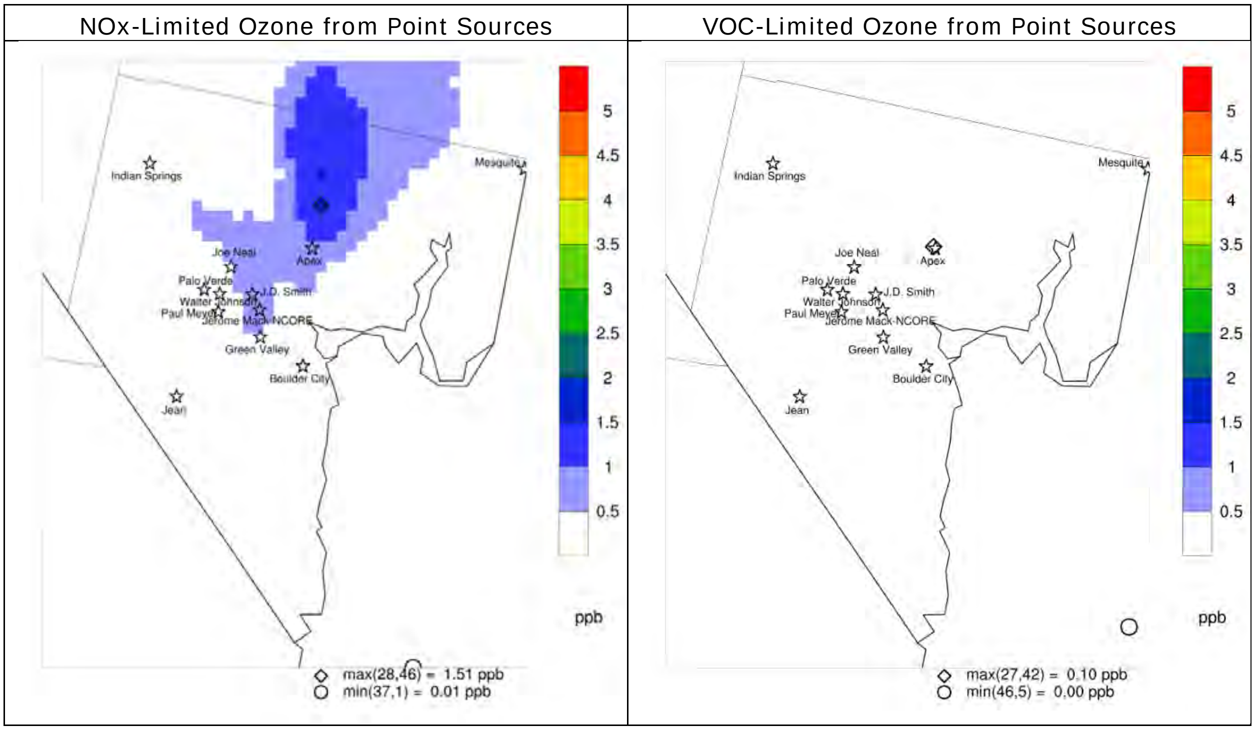


Figure 11-11(d). NOx- and VOC-limited MDA8 ozone contributions from Clark County point source emissions averaged over the top 10 simulated ozone days.

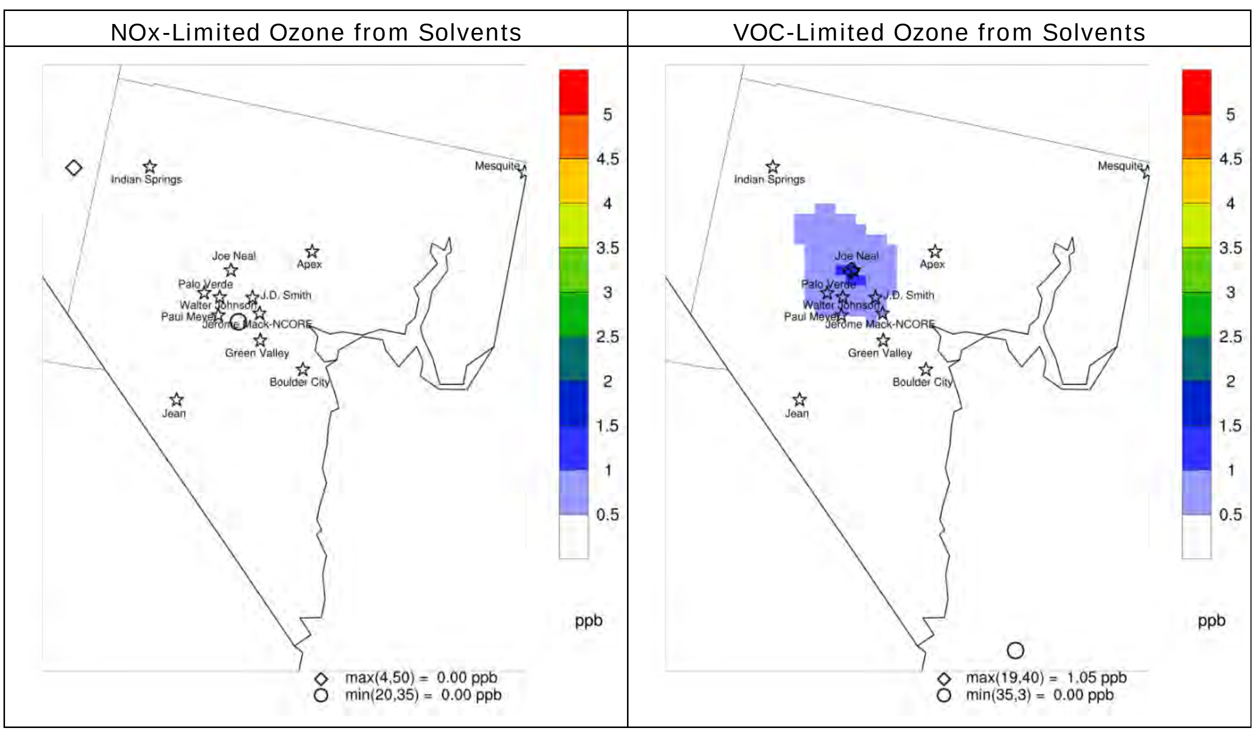


Figure 11-11(e). NOx- and VOC-limited MDA8 ozone contributions from Clark County solvent emissions averaged over the top 10 simulated ozone days.

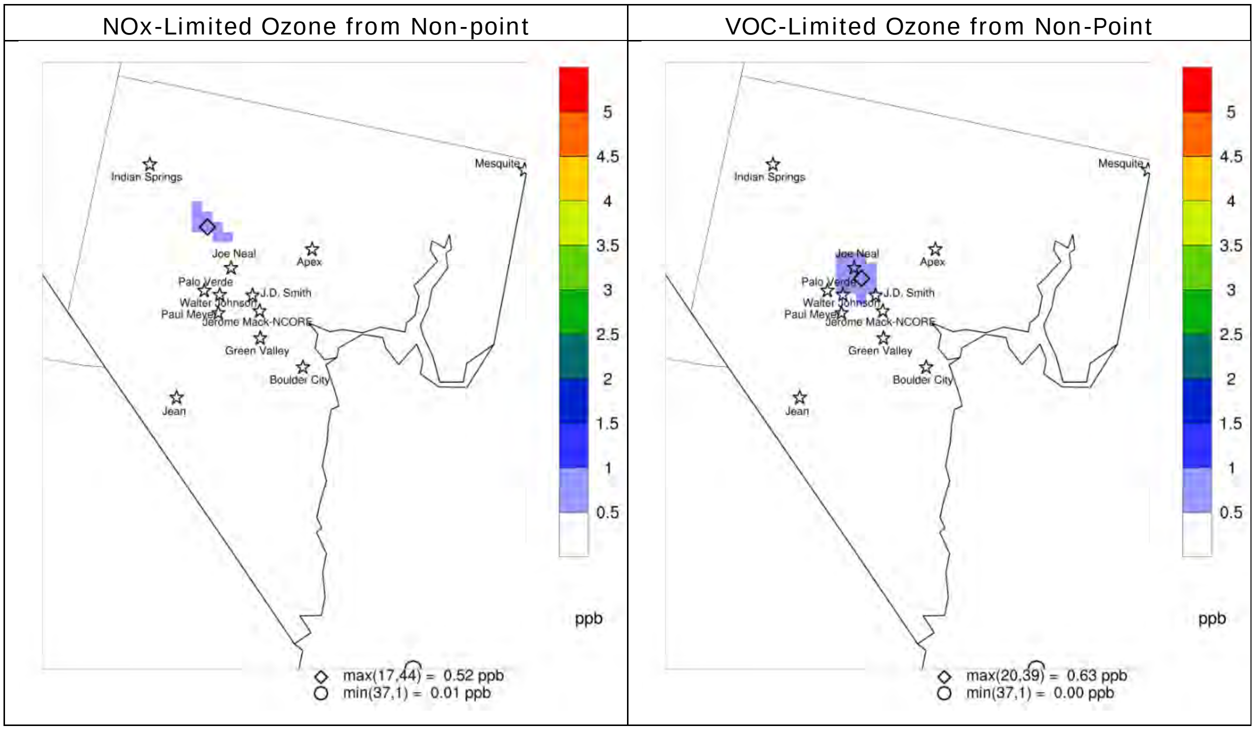


Figure 11-11(f). NOx- and VOC-limited MDA8 ozone contributions from Clark County non-point (area) emissions averaged over the top 10 simulated ozone days.

12.0 WEIGHT OF EVIDENCE ANALYSES

This Section describes the weight of evidence (WOE) component of the project. The purpose of the WOE is to present additional data analyses and modeling results, beyond the standard modeled attainment test, that add additional support to the overall attainment demonstration. The specific types of selected analyses follow from EPA modeling guidance (EPA, 2018a) and the Modeling Protocol developed during the early phases of this project (Ramboll, 2022a).

12.1 Approach

Ramboll performed 7 individual WOE analyses, grouped under the three general areas recommended by EPA (2018):

1) Additional modeling analyses (independent regional/national modeling, other local modeling/research, modeled source apportionment and sensitivity analysis, alternative SMAT configurations and approaches)

   - We summarized EPA's initial and final interstate transport modeling using their 2016v2 and 2016v3 Modeling Platforms (EPA, 2022d; 2023a).
   - We re-ran SMAT for an alternative base year DV period centered on 2017 rather than 2016 (4^{th} high MDA8 ozone days from 2015 through 2019).
   - We re-ran SMAT for the standard 2016-2018 base year DV period but with annual 4^{th} high MDA8 ozone values during 2014-2018 recalculated by removing fire-influenced days (as identified by DES/DAQ) from the monitored annual MDA8 ozone database.
   - We ran a CAMx source apportionment application (Section 11) tracking international, US, and local source category contributions to ozone in Clark County, as well as NOx- and VOC-limited chemistry patterns.

2) Trends in emissions and air quality measurements

   - We assessed Clark County historical and projected future NOx and VOC emission trends over 2008-2033 using a combination of Clark County Inventories.
   - Using EPA's statistical software package and data sets to meteorologically adjust ambient ozone trends (EPA, 2023b; Wells et al., 2021), we developed a set of meteorologically adjusted 2000-2022 ozone trends reflecting the removal of fire-influenced or "EE-like" days (as identified by DES/DAQ).

3) Additional emission controls/reductions

   - We ran CAMx for the 2023 future base case with all wildfire emissions removed and noted impacts to the 2023 projected DVs.

Appendix A describes results from additional 2023 future year emissions sensitivity tests.

12.2 Conclusions

The weight of evidence presented here, according to additional modeling, analyses of precursor emissions and ambient ozone trends, and removal of wildfires from measurements and modeling, all support the results from the photochemical modeling demonstration that the Clark County Moderate Ozone Nonattainment Area will attain the 2015 ozone NAAQS by the attainment year of 2023. Results supporting this conclusion are summarized below, and details of our analyses are presented in the remainder of this report.

12.2.1 Summary of Results

- EPA's initial and final interstate transport modeling:
  - In agreement with our 2023 future base case modeling results, both of EPA's modeling platforms consistently show that the CCNAA will attain the 2015 ozone NAAQS in 2023.
  - EPA source apportionment modeling consistently shows that California and fires together contribute about as much to Clark County 2023 DVs as Nevada's own contribution.

- 2023 SMAT DV projections using a base year DV period centered on 2017:
  - Projected DVs at monitoring sites were consistent with and slightly lower than using a base year DV period centered on 2016, reflecting the slightly lower base year DV. SMAT-CE indicated no exceedances in 2023 in either case.

- 2023 SMAT DV projections using a base year DV period centered on 2016 but with fire-influenced days removed from the observed MDA8 ozone database:
  - Reductions in 2016-2018 DVs of 0 to 2 ppb resulted from the removal of fire-influence days, and 2023 projected DVs were similarly lower with no exceedances among any monitoring site.

- Ozone source apportionment results (Section 11):
  - Contributions to model-projected 2023 DV at Joe Neal are consistent with EPA's two interstate source apportionment analyses.
  - Natural and non-US ozone concentrations comprise the majority of ozone at 49 ppb (71% of the 69 ppb DV), California anthropogenic emissions contribute an average of 7 ppb (11%), Clark County contributes 11 ppb (16%), fires within the North American modeling domain contribute 2.4 ppb (4%), and the rest of the US contributes 1.7 ppb (3%).
  - The modeled contributions to the 2023 DV at Joe Neal from all global international anthropogenic emissions are 13 ppb at Joe Neal, a value that is consistent throughout the entire inter-mountain western US and consistent with many previous studies.

- Clark County 2008-2033 NOx and VOC emission trends:
  - A substantial 56% NOx reduction has occurred between 2008 and 2023 and continued reductions are projected out to 2033 with an overall 2011-2033 reduction of 64%. NOx reductions are driven by large decreases among the on-road and nonroad motor vehicle sectors.
  - VOC emissions have generally decreased over the 2008-2023 period by 25% and a continued net reduction of 26% is projected out to 2033. VOC decreases are driven by on-road and nonroad sectors but curbed by increases in the nonpoint sector because of burgeoning population and commercial activity.
  - Growth in airport emissions over the 2008-2033 period contribute to increasing NOx and VOC.
  - The area is expected to continue its evolution from a transitional NOx- and VOC-sensitive environment toward a relatively more NOx-sensitive environment out to 2033. Therefore, after a period of some NOx-disbenefits in certain areas, continued NOx reductions will be effective in lowering ozone into the future while VOC reductions will be increasingly less effective.

- Meteorologically adjusted 2000-2022 ozone trends with fire-influenced days removed, based on the 97th percentile that better represents 4th highest MDA8 ozone during the May-September ozone season:

- The MDA8 ozone trends have tended to flatten over the past 10 years, with a substantial degree of remaining interannual variability after filtering for weather. It is likely that this remaining variability is related to other western regional influences, particularly wildfire activity.
- The flattened trends are in sharp contrast to large anthropogenic emission reductions achieved across the region during this time, further suggesting influences from uncontrollable sources.
- The no-fire trendlines without the meteorological adjustment correctly show reduced 97th percentile MDA8 ozone only in the years when fire-influenced days were removed, by typically 2 to 3 ppb but as much as 5.5 ppb in 2020 at Joe Neal.
- The meteorologically adjusted no-fire 97th percentile trendlines exhibit similar interannual variability as the original trendlines but a substantial reduction in recent ozone levels at all sites.
- 2023 extrapolations for the meteorologically adjusted 97th percentile trendline using all days range from 68.1 to 72.3 ppb.
- 2023 extrapolations for the meteorologically adjusted 97th percentile trendline without fire-influenced days range from 66.7 to 71.0 ppb.

- CAMx 2023 future base case simulation with all wildfire emissions removed:
  - Projected DVs at monitoring sites were all well below the ozone NAAQS and were 1-3 ppb lower than the DV projections that include the wildfire emissions in the 2023 future base case.
  - The modeled wildfire contribution of 1-3 ppb agreed with EPA's source apportionment estimates from their 2016 MPs (EPA, 2022d, 2023a).

12.3 EPA Interstate Transport Modeling

In January 2022, EPA released the 2016v2 Modeling Platform (MP) based on the "fj" version of their US emissions inventory (EPA, 2022b), and used it to project future ozone DVs for the years 2023, 2026 and 2032 (EPA, 2022c)[22]. EPA estimated that ozone DVs in Clark County would attain the 2015 ozone NAAQS in 2023 (Table 12-1) and more certainly would attain in 2026 and 2032. Table 12-1 also lists the 2023 future base case projected DVs determined in this study (Section 9.3), which are very similar to EPA's results.

In late 2022, EPA developed the 2016v3 MP (EPA, 2022c). In response to public comments on the 2016v2 base year and projected emissions inventories, the 2016v3 emissions platform (version "gf") includes "updates, corrections, improved methods, and refinements to some projection factors due to newly released data" (EPA, 2022c). Additionally, EPA replaced 36US3 North American grid BCs drawn from the Hemispheric CMAQ (H-CMAQ) model with new boundary concentrations derived from the GEOS-Chem global chemistry model. Biogenic emissions were developed using BEIS4/BELD6, replacing BEIS3.7/BELD5. Finally, EPA estimated three-dimensional model inputs for lightning NOx (LNOx) emissions.

EPA repeated their projections of future ozone DVs using the 2016v3 MP (EPA, 2023a)[23], which continued to show that Clark County will attain the 2015 ozone NAAQS in 2023 (Table 12-1). There was very little change in results from the 2016v2 projections, and the new results converged somewhat toward the projected DVs determined in this study.

[22] https://gaftp.epa.gov/Air/aqmg/2016v2_Platform_Modeling_Data/

[23] https://www.epa.gov/interstate-air-pollution-transport/final-disapproval-good-neighbor-state-implementation-plans

Table 12-1. Projected 2023 ozone DVs (ppb) at Clark County ozone monitoring sites based on EPA's 2016v2/fg and 2016v3/gf modeling platforms and from the 2023 future base case scenario in this study (CCNAA).

Site ID	2023fj Avg 3x3	2023gf Avg 3x3	CCNAA Avg 3x3
320030022	66.1	65.6	65.2
320030023	58.3	58.5	57.2
320030043	68.5	68.4	67.7
320030071	67.7	67.9	67.9
320030073	67.7	67.9	67.2
320030075	70.0	69.9	69.0
320030298	66.6	66.8	67.3
320030540	65.0	64.4	64.1
320030601	61.8	62.2	61.5
320031019	64.8	64.4	63.9
320032002	67.9	67.5	67.3
320037772	65.1	63.8	62.3

EPA also used the 2016v2 and 2016v3 MPs for their preliminary and final interstate ozone transport modeling for the 2015 ozone NAAQS (EPA, 2022d; 2023a). In both cases, 2023 DV contributions were estimated from individual states, foreign sources, fires and biogenic emissions. Table 12-2 shows results from the 2016v2 while Table 12-3 shows results from the 2016v3. From the 2016v2, EPA estimated that California's contribution to ozone DVs in Clark County is roughly as large as Nevada's own contribution, while most ozone is transported into the LVV from boundary conditions (BCs) reflecting total global contributions. Fires and biogenic emissions were estimated to be modest contributors (1-3 ppb each) and Canada plus Mexico were modeled to contribute even less (1-2 ppb).

Table 12-2. Projected 2023 ozone DV contributions (ppb) from Nevada, other states, foreign sources, fires, and biogenic emissions at Clark County ozone monitoring sites based on EPA's 2016v2 modeling platform (https://gaftp.epa.gov/Air/aqmg/2016v2_Platform_Modeling_Data/ accessed April 2022).

Site ID	AZ	CA	NV	Canada +Mexico	2023 Fires	IC/BC	Biogenic
320030022	0.31	6.90	6.58	1.33	1.57	47.03	1.83
320030043	0.37	6.96	8.19	1.48	2.30	46.43	1.94
320030071	0.19	7.40	6.31	1.31	3.10	46.72	1.70
320030073	0.19	7.40	6.31	1.31	3.10	46.72	1.70
320030075	0.21	7.44	8.46	1.28	0.67	49.59	1.75
320030298	0.46	7.60	6.47	1.84	1.77	45.58	1.99
320030540	0.42	6.89	8.45	1.73	1.84	42.94	1.86
320031019	0.13	6.66	0.99	1.61	2.21	51.22	1.42
320032002	0.36	7.79	10.57	1.31	0.78	44.48	1.97
320037772	0.07	5.54	1.66	0.79	1.90	53.25	1.29

Table 12-3. Projected 2023 ozone DV contributions (ppb) from Nevada, other states, foreign sources, fires, and biogenic emissions at Clark County ozone monitoring sites based on EPA's 2016v3 modeling platform (https://www.epa.gov/interstate-air-pollution-transport/final-disapproval-good-neighbor-state-implementation-plans/ accessed February 2023).

Site ID	AZ	CA	NV	Canada +Mexico	2023 Fires	IC/BC	Biogenic +LNOx
320030022	0.41	7.52	6.43	1.46	0.87	45.30	2.83
320032023	0.91	4.82	1.95	1.76	0.79	44.98	2.45
320030043	0.77	6.97	9.05	1.94	2.13	42.30	4.04
320030071	0.65	6.84	9.97	1.70	2.42	41.42	3.82
320030073	0.65	6.84	9.97	1.70	2.42	41.42	3.82
320030075	0.49	8.96	10.53	1.45	1.36	42.68	3.57
320030298	0.68	7.30	5.34	1.64	2.25	45.11	3.32
320030540	0.65	7.57	7.95	1.37	1.36	41.03	3.39
320030601	0.74	7.22	2.81	1.70	1.59	44.07	3.20
320031019	0.27	6.63	1.38	1.86	1.69	49.49	2.35
320032002	0.50	8.17	10.07	1.27	1.53	41.84	3.40
320037772	0.23	6.52	1.93	0.97	1.87	49.31	2.19

The ozone apportionment results in Table 12-3 are very similar according to the 2016v3 results, but with some notable differences. Contributions from Arizona, California, Nevada, and Canada plus Mexico increased somewhat, while contributions from fires and BCs decreased slightly. Contributions from biogenic emissions increased by about 0.5 ppb and the addition of LNOx in the 2016v3 increased the natural contribution to 2-4 ppb. Both sets of 2016 MP modeling results consistently show that California and fires together contribute about as much to Clark County 2023 DVs as Nevada's own contribution.

12.4 Alternative 2023 DV Projections

12.4.1 Flexibility in RRF Calculations

EPA's guidance includes some flexibility to modify the recommended ozone DV projection procedure. One is to consider shifting the base year DV period by a year or two from which to project the future year DV, to further account for variability in DV levels over the base year period.

Another consideration is to account for "exceptional event like" days (i.e., days that might not qualify as official exceptional events) such as wildfires. EPA (2019c) includes provisions for excluding such days with appropriate justification. There are two approaches to account for exceptional event like days in the attainment year DVF projection: (1) remove such days from the base year DV calculation so that the DV more faithfully reflects typical local to regional anthropogenic ozone conditions and patterns; (2) remove such days from the list of modeled highest 10 base year ozone days in the RRF calculation so that the projection more faithfully reflects impacts from typical local to regional emission reductions. As described in the Modeling Protocol (Ramboll, 2022a) several days of 2016 warrant exclusion, but it would be problematic to exclude a large number.

12.4.2 DV Projections Using Base DV Centered on 2017

We applied SMAT-CE with the most current monitoring database from EPA containing 2002-2020 4th high MDA8 ozone for all official sites operating in Clark County. In this analysis we ran SMAT-CE using the 2017-2019 3-year DV period for base monitored ozone (2015-2019 4th highs centered on 2017), as opposed to the 2016-2018 DV used previously for the 2023 future base case and control measure scenarios. All other configuration options remained the same as our previous SMAT-CE runs, which employed default or standard settings throughout the setup menu. We made no special modifications to monitored data or specific selection of modeled days for the RRF calculation.

12.4.2.1 Results at Monitoring Sites

Table 12-4 shows projected DV results based on the original 2016-2018 base year DVs and the 2017-2019 base year DVs in this analysis. SMAT-CE continued to indicate no exceedances in 2023. The peak average projected DV was 68.4 ppb at Joe Neal and 68.5 ppb at Walter Johnson, respectively.

Table 12-4. 2023 projected DVs at each monitoring site within the LVV according to SMAT-CE calculations using the 2016-2018 and 2017-2019 average base year DVs. Red values indicate exceedances of the 2015 ozone NAAQS, green indicate values below the NAAQS. Sites noted with an asterisk continued to exceed the ozone NAAQS in 2020, leading to the bump up from Marginal to Moderate nonattainment status.

Site ID	Site Name	2016-2018 DV		2017-2019 DV	
		Base DV Avg 3x3	2023 DV Avg 3x3	Base DV Avg 3x3	2023 DV Avg 3x3
320030022	Apex	70.3	65.2	69.0	64.0
320030023	Mesquite	61.3	57.2	61.3	57.2
320030043	Paul Meyer*	72.0	67.7	71.3	67.1
320030071	Walter Johnson*	72.3	67.9	73.0	68.5
320030073	Palo Verde	72.3	67.2	71.0	66.0
320030075	Joe Neal*	75.0	69.0	74.3	68.4
320030298	Green Valley*	71.0	67.3	71.5	67.7
320030540	Jerome Mack	68.7	64.1	68.3	63.8
320030601	Boulder City	66.0	61.5	66.0	61.5
320031019	Jean	68.3	63.9	67.7	63.3
320032002	J.D. Smith	72.5	67.3	72.0	66.9
320037772	Indian Springs	68.5	62.3	68.3	62.1

12.4.3 DV projections With Fire-Influenced Days Removed

We re-ran SMAT-CE for the standard 2016-2018 base year DV period but with annual 4th high MDA8 ozone values during 2014-2018 recalculated by removing fire-influenced days from the monitored annual MDA8 ozone database. The DES/DAQ provided a list of fire-influenced dates compiled for the years 2016, 2018, and 2020-2022 (Table 12-5; Sonoma Technology, 2023). During the 2016-2018 DV period, individual 4th high MDA8 values in 2016 and 2018 were reduced at most sites by the removal of fire-influenced days, which further reduced all three DVs during 2016-2018.

Table 12-5. Fire-influenced days during 2016, 2018, and 2020-2022 identified and analyzed by DES/DAQ and Sonoma Technology (2023).

Event Date(s)	DES Identified Event Type
June 24-25, 2016	Southern California wildfire influence
June 27, 2016	Southern California wildfire influence
July 24, 2016	Southern California wildfire influence
July 26-29, 2016	Southern California wildfire influence
August 24, 2016	Southern California wildfire influence
June 23, 2018	Wildfire
June 27, 2018	Wildfire
July 14–17, 2018	Wildfire
July 25–27, 2018	Wildfire
July 30–31, 2018	Wildfire
August 6–7, 2018	Wildfire
August 3, 2020	Wildfire
August 7, 2020	Wildfire
August 18–21, 2020	Wildfire
September 26, 2020	Wildfire
June 11-12, 2021	Local smoke
June 16-17, 2021	Regional wildfire smoke
July 20, 2021	Regional wildfire smoke
August 2-3, 2021	Regional wildfire smoke
August 7, 2021	Regional wildfire smoke
August 19, 2021	Regional wildfire smoke
September 8, 2021	Regional wildfire smoke
June 16,2022	Regional wildfire smoke
July 17, 2022	Regional wildfire smoke
July 28-29,2022	Regional wildfire smoke
September 1-2, 2022	Regional wildfire smoke

12.4.3.1 Results at Monitoring Sites

Table 12-6 shows 2016-2018 base year and projected DV results including fire-influenced days (duplicated from the 2023 future base case results) and with fire-influenced days removed. In both cases, the standard CAMx 2016 base case and 2023 future base were used (including wildfire emissions) for the 2023 projections; i.e., only the 2016-2018 DVs were modified and not the CAMx results. According to SMAT-CE, reductions in 2016-2018 DVs of 0 to 2 ppb resulted from the removal of fire-influence days, and 2023 projected DVs were similarly lower with no exceedances among any monitoring site. The peak average 2016-2018 DV was reduced from 75 to 73 ppb. The peak average projected 2023 DV was reduced from 69 to 67 ppb at Joe Neal.

Table 12-6. 2016-2018 and 2023 projected DVs at each monitoring site within the LVV according to SMAT-CE calculations using the official 2016-2018 DVs and the modified 2016-2018 DVs reflecting the removal of fire-influenced days in 2016 and 2018 (Table 12-5). Projected 2023 DVs were determined using the 2023 future base case CAMx results that include influences from wildfires. Red values indicate exceedances of the 2015 ozone NAAQS, green indicate values below the NAAQS. Sites noted with an asterisk continued to exceed the ozone NAAQS in 2020, leading to the bump up from Marginal to Moderate nonattainment status.

Site ID	Site Name	2016-2018 DV		2016-2018 DV no fire days	
		Base DV Avg 3x3	2023 DV Avg 3x3	Base DV Avg 3x3	2023 DV Avg 3x3
320030022	Apex	70.3	65.2	69.7	64.7
320030023	Mesquite	61.3	57.2	61.3	57.2
320030043	Paul Meyer*	72.0	67.7	71.0	66.8
320030071	Walter Johnson*	72.3	67.9	71.0	66.6
320030073	Palo Verde	72.3	67.2	71.0	66.0
320030075	Joe Neal*	75.0	69.0	73.3	67.5
320030298	Green Valley*	71.0	67.3	70.0	66.3
320030540	Jerome Mack	68.7	64.1	68.0	63.5
320030601	Boulder City	66.0	61.5	65.3	60.9
320031019	Jean	68.3	63.9	68.0	63.6
320032002	J.D. Smith	72.5	67.3	70.5	65.5
320037772	Indian Springs	68.5	62.3	67.5	61.4

12.5 Clark County Emission Trends

Ramboll compiled historical and projected future Clark County anthropogenic emission inventories from which to develop NOx and VOC emission trendlines. Centered on 2017, the resulting trendlines span 9 years prior and 16 years forward. Historical emissions in 2008 and 2015 were taken from the Ozone Redesignation Request and Maintenance Plan for the 1997 Ozone NAAQS (Clark County, 2018), while 2017 anthropogenic emissions and projections to 2023 and 2033 were taken from the second Maintenance Plan (Clark County, 2021).

It is important to note that the historical inventories reported here for 2008, 2015 and 2017 were developed using different data sources, methods, and models unique to each inventory year. This leads to some inconsistencies in trendlines for those sectors affected by substantial updates, improvements, or refinements, e.g., the evolution of MOBILE, NONROAD, and MOVES models and associated local data used to estimate emissions for on-road and nonroad motor vehicle sectors. Additionally, substantial methodological and data updates for other sectors have occurred and are anticipated, e.g., the use of new information from field research and models from which to estimate emissions from volatile chemical products (VCP) that comprise a major fraction of the nonpoint VOC emissions sector. Nevertheless, the trendlines developed here provide a general sense for the evolution of NOx and VOC emissions over a 25 year span.

Tables 12-7 and 12-8 tabulate the Clark County anthropogenic emission estimates over 2008-2033 by major source sector and Figure 12-5 shows the resulting trendline for total anthropogenic NOx and VOC. A substantial NOx reduction has occurred between 2008 and 2023, by 56%. Continued reductions are projected out to 2033, with an overall 2008-2033 reduction of 64%. NOx reductions over the entire period are driven primarily by large decreases among the on-road and nonroad motor vehicle sectors, only curbed by increases in airport-related emissions.

VOC emissions have also generally decreased over the 2011-2023 period by 25% and are projected to continue decreasing through 2033 for an overall reduction of 26%. VOC decreases over the period are driven primarily by on-road and nonroad mobile sources but are curbed by growth in the nonpoint sector because of historical and future burgeoning population and commercial activity. Recent growth in airport emissions also contribute to increasing VOC since 2017.

The area is expected to continue its evolution from a transitional NOx- and VOC-sensitive environment toward a relatively more NOx-sensitive environment out to 2033. Therefore, after a period of some NOx-disbenefits in certain areas, continued NOx reductions will be effective in lowering ozone into the future while VOC reductions will be increasingly less effective.

Table 12-7. Clark County anthropogenic NOx emissions trends (TPD) by major source category. Data from 2008 and 2015 are reported by Clark County (2018) while data from 2017 through 2033 are reported by Clark County (2021). Sectors noted in green (red) exhibit a net reduction (increase) from 2008 to 2023 and beyond to 2033.

Sector	2008	2015	2017	2023	2033
Point Source	28.97	11.60	12.34	11.41	11.33
Nonpoint Source	6.60	5.94	4.69	5.03	4.78
Mobile: On-road	89.5	64.30	42.20	22.22	11.13
Mobile: Nonroad	40.63	27.69	38.87	24.48	16.33
Aviation: Commercial + Federal	12.68	13.35	11.90	15.53	19.77
TOTAL	178.38	122.88	110.0	78.67	63.34

Table 12-8. Clark County anthropogenic VOC emissions trends (TPD) by major source category. Data from 2008 and 2015 are reported by Clark County (2018) while data from 2017 through 2033 are reported by Clark County (2021). Sectors noted in green (red) exhibit a net reduction (increase) from 2008 to 2023 and beyond to 2033.

Sector	2008	2015	2017	2023	2033
Point Source	1.50	2.42	2.95	2.62	2.63
Nonpoint Source	67.56	60.12	64.69	67.83	71.31
Mobile: On-road	42.46	33.04	26.27	17.85	11.50
Mobile: Nonroad	42.07	31.10	28.93	27.29	27.86
Airports: Commercial + Federal	3.39	3.75	1.96	2.64	3.05
TOTAL	156.98	130.43	124.08	118.23	116.35

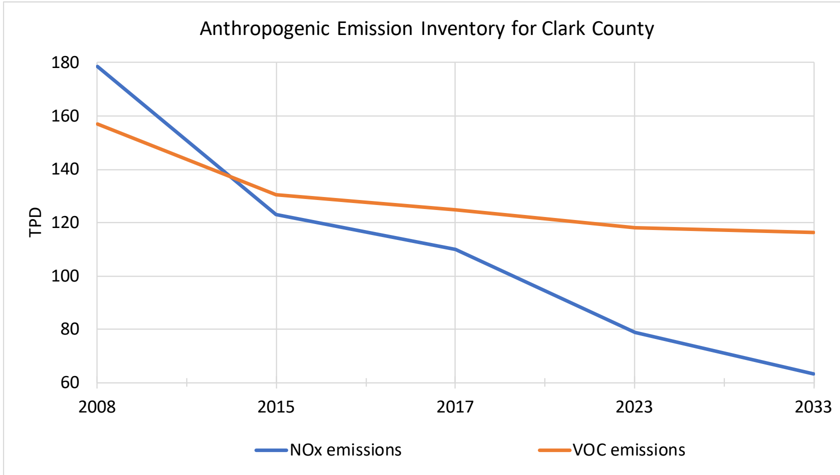


Figure 12-1. Clark County total anthropogenic NOx and VOC emission trends (TPD) from 2008 through 2033. Data from 2008 and 2015 are reported by Clark County (2018) while data from 2017 through 2033 are reported by Clark County (2021).

12.6 Meteorologically Adjusted Ozone Trends

Variations in interannual weather patterns affect ozone DVs year-to-year, which can obscure the assessment of air quality trends. Warm, clear and stagnant summers usually lead to more frequent high ozone episodes while cool, cloudy and breezy summers lead to better air quality. EPA uses a statistical model to adjust monitored ozone levels for the effects of seasonal weather variability "to provide a more accurate assessment of the underlying trend in ozone caused by emissions" (EPA, 2023e). In other words, by filtering interannual variations among key meteorological factors toward climatological averages, the adjusted long-term ozone trend should better reflect influences from long-term emission changes. In this context, we expect EPA is referring to anthropogenic emission reductions at local to regional scales that primarily influence ozone at specific monitors. It is important to note that, especially in the western US, ozone trends reflect contributions from several other substantial uncontrollable influences that are not addressed by meteorological filtering alone, such as interannual wildfire activity and sources of background contributions (including stratospheric intrusions, neighboring countries, intercontinental transport from Asia, etc.). The 2020 COVID-19 pandemic also impacted anthropogenic activities and emissions.

Wells et al. (2021) describe the statistical models used to determine the trendline adjustments and how they are fit independently for each ozone monitoring site using local ozone and weather data. The statistical technique, called forward selection, chooses the weather variables that are most important for ozone formation at each location. Variables are selected iteratively according to greatest improvement in the model fit, up to a maximum of 10 variables. As we would expect, the variables of greatest importance, and the resulting statistical adjustments applied, all tend to have a strong geographic coherence. Nevertheless, since the adjustment is statistical, it likely cannot remove all interannual weather influences from the trendlines.

12.6.1 Ozone Trends With Fire-Influenced Days Removed

Ramboll developed meteorologically adjusted 2000-2022 ozone trends and compared them to trends with fire-influenced or "EE-like" days removed since 2016 (as identified by DES/DAQ; Table 12-5). The analysis focused on the four consistently highest ozone monitoring sites in Clark County: Joe Neal, Walter Johnson, Paul Meyer, and Palo Verde. We obtained EPA's statistical software package, run scripts, and input datasets (B. Wells, personal communication). The fire-influenced days from 2016 through 2022 listed in Table 12-5 were removed from EPA's May-September 2000-2022 MDA8 ozone database for the four sites listed above and the software scripts were used to calculate the 97th percentile trendlines, which closely corresponds to 4th highs for the number of days over the ozone season.

Figure 12-6 shows the resulting ozone trend lines at the four Clark County monitoring sites, where the 97th percentile trendlines for all-day (red) and no-fire (blue) cases are overlaid for direct comparison. The dotted lines show the meteorologically unadjusted trends while the solid lines show the trends after filtering the interannual weather variability. The trends in the all-day cases have tended to flatten over the past 10 years, with a substantial degree of remaining interannual variability after filtering for weather. It is likely that this remaining variability is related to other western regional influences that weather parameters cannot account for, particularly the significant increase in western wildfire activity over this later period. The flattened trends are in sharp contrast to large anthropogenic emission reductions achieved across the region during this time, further suggesting influences from uncontrollable sources. The significant uptick in 97th percentile ozone at Palo Verde over 2020-2021 (+13 ppb unadjusted, +9 ppb adjusted) is particularly notable as it is much larger than at all other sites and is reflected throughout the frequency distribution, from the median through the 90th percentile (EPA, 2023e; not shown). The cause for this behavior is not readily apparent.

The no-fire trendlines without the meteorological adjustment correctly show reduced 97th percentile MDA8 ozone only in the years when fire-influenced days were removed, by typically 2 to 3 ppb but as much as 5.5 ppb in 2020 at Joe Neal. Interestingly, the meteorologically adjusted no-fire trendlines change in all years. We suspect that removing high ozone days during the few later years changed the diagnosed statistical relationships and associated ozone adjustments enough to alter the data throughout the analysis period. The meteorologically adjusted no-fire trendlines exhibit a similar interannual variability as the all-day trendlines but result in a substantial reduction in recent ozone levels. Note that removal of fire days in 2020-2022 slightly reduces the large uptick in 97th percentile ozone at Palo Verde over this period.

Linear regressions were fit to the meteorologically adjusted trendlines to further clarify the 20-year mean trends and impacts from removing fire-influenced EE-like days, as well as to project the trends to 2023. Table 12-9 presents pertinent statistics and 2023 projections from the meteorological adjusted 97th percentile trendlines. The regressed projections to 2023 show MDA8 ozone below the NAAQS at three of the four sites in the all-day and no-fire cases.

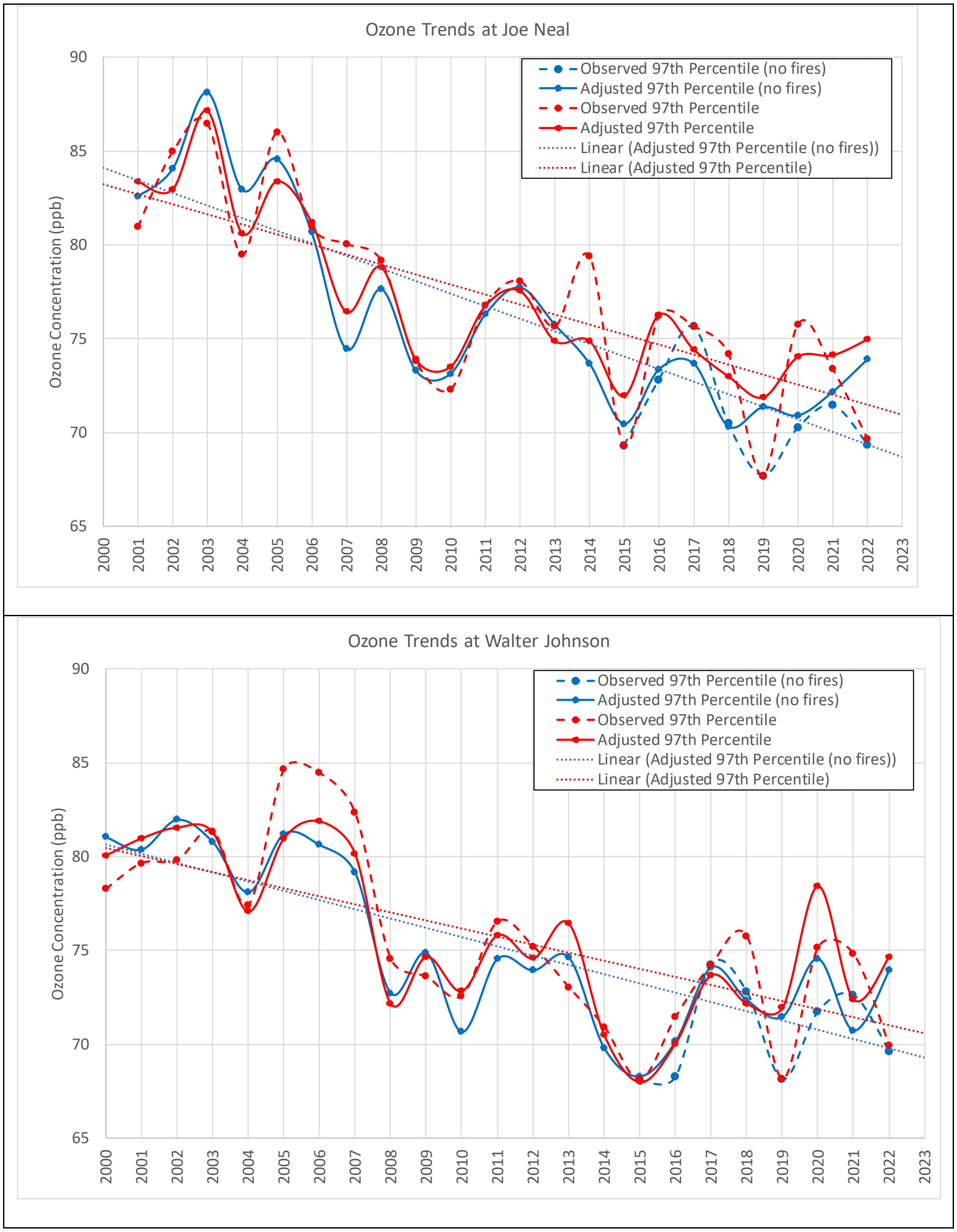


Figure 12-2. 2001-2022 ozone trends at Clark County monitoring sites: 97th percentile for all days (red) for observed (dashed line) and meteorologically adjusted (solid line) May-September MDA8 ozone; and 97th percentile resulting from removal of fire-influenced days in 2016 through 2022 (blue) for observed (dashed lines) and meteorologically adjusted (solid line) May-September MDA8 ozone. The linear regression lines for adjusted all-days and no-fire days are shown as the dotted lines and extend to 2023.

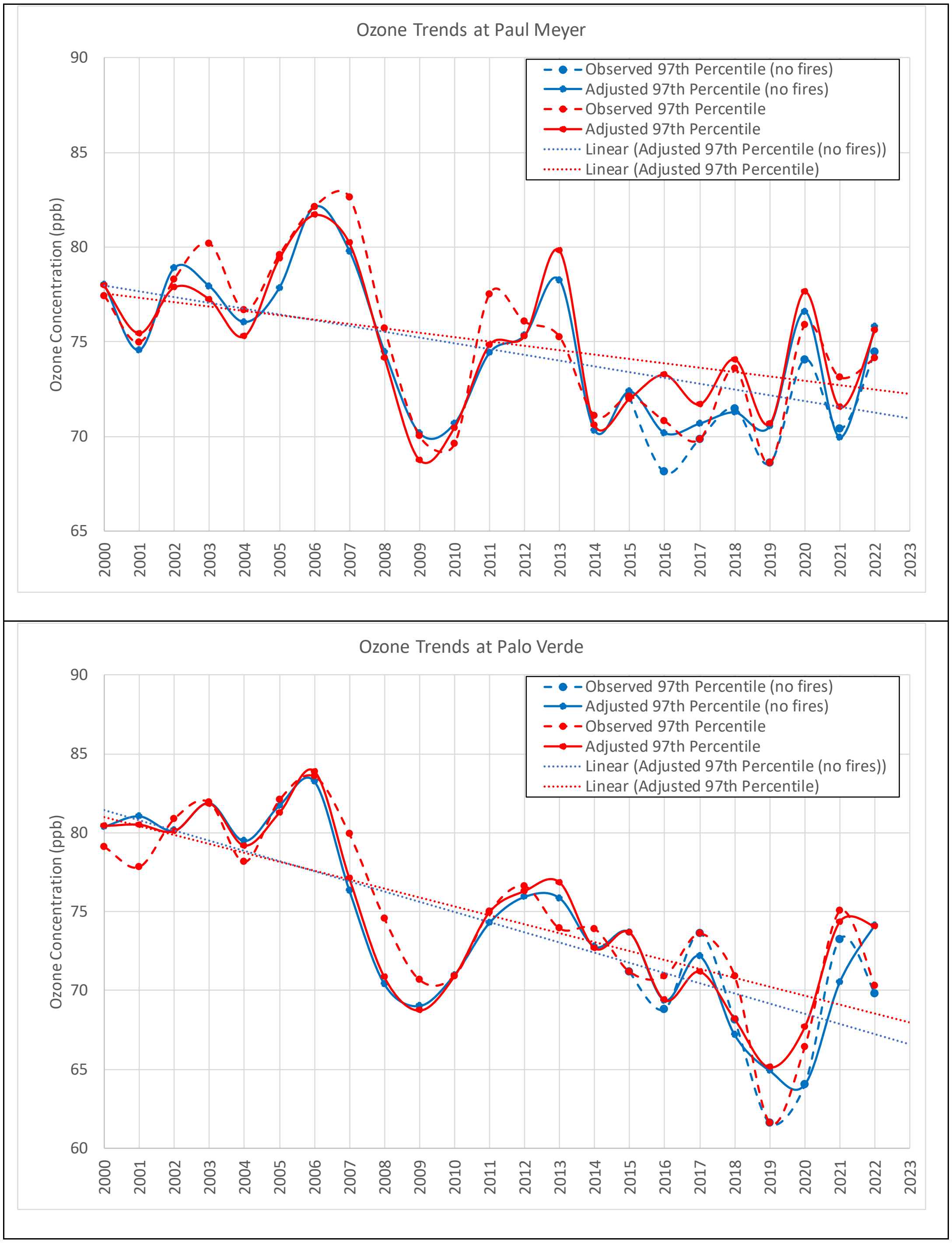


Figure 12-6 (concluded).

Table 12-9. Regression statistics for all-days and no-fire days meteorologically adjusted 97th percentile MDA8 ozone trendlines in Figure 12-6 along with the corresponding 2023 projected 97th percentile MDA8 ozone.

Site	Slope (ppb/yr)		R^2		20-year change		2023 Projection	
	All Days	No Fire	All Days	No Fire	All Days	No Fire	All Days	No Fire
Joe Neal	-0.5352	-0.6699	0.67	0.70	-10.7	-13.4	70.9	68.6
Palo Verde	-0.5661	-0.6444	0.54	0.61	-11.3	-12.9	68.1	66.7
Walter Johnson	-0.4281	-0.4946	0.47	0.61	-8.6	-9.9	70.7	69.3
Paul Meyer	-0.2304	-0.3037	0.19	0.31	-4.6	-6.1	72.3	71.0

12.7 CAMx 2023 Future Base Case With Wildfire Emissions Removed

The 2023 future year base case CAMx run was repeated but removing all wildfire emissions within the 12US2 and CC4c2 modeling domains. All other inputs were not modified (Table 12-10), and only the 12US2/CC4c2 2-way nested grids were run using the 2023 12US2 future base case boundary conditions extracted from the 36US3 grid. In this test we isolated the effects of wildfires on 2023 DV projections by considering a scenario where all wildfires that occurred in 2016 would not occur in 2023.

12.7.1 SMAT-CE Configuration

We applied SMAT-CE identically to the original 2023 future base case scenario, specifying 2016-2018 3-year DV period for base monitored ozone (2014-2018 4th highs centered on 2016). All other configuration options remained the same as the original SMAT-CE run, which employed default or standard settings throughout the setup menu. We made no special modifications to monitored data or specific selection of modeled days for the RRF calculation.

12.7.2 Results at Monitoring Sites

Table 12-11 shows projected DV results at monitoring sites that reported sufficient data during the 2016-2018 base year DV period. Projected DVs were all well below the ozone NAAQS and were 1-3 ppb lower than the DV projections that include the wildfire emissions in the 2023 future base case. Therefore, the modeled wildfire contribution to projected DVs of 1-3 ppb agree with EPA's source apportionment estimates from their 2016 MPs (Tables 12-2 and 12-3; EPA, 2022c, 2023a). The peak average projected DV was 67.6 ppb at Joe Neal.

Table 12-10. CAMx model configuration for the CCNAA 2023 future base case simulation with wildfires removed (noted in red).

Model Component	CCNAA Application	Comment
Model Code	CAMx v7.20 - May 2022	
Modeling Period	May 1 – August 31, 2016	
Horizontal Grids		
Map Projection	Lambert Conic Conformal	EPA 2016 MP
36 km (36US3)	172 x 148 cells	Not run
12 km (12US2)	396 x 246 cells (no buffer cells)	EPA 2016 MP (2-way nesting)
4 km (CC4c2)	50 x 62 cells (with buffer cells)	CCNAA grid (2-way nesting)
Vertical Grid	35 layers	EPA 2016 MP, defined by WRF
Initial Conditions	12US2/CC4c2 IC May 1 from 36US3	2023 future year base case
Boundary Conditions	12US2 BC from 36US3	2023 future year base case
Time Zone	UTC	EPA 2016 MP
Emissions		
36/12 km Data Sources	EPA 2023fj from 2016v2 MP	Wildfires removed from 12US2 grid
4 km Data Sources	EPA 2023fj from 2016v2 MP + 2023 Clark County Data, elevated Reid LTO emissions	Wildfires removed
Models/Processing Tools	SMOKE, MOVES3, SMOKE-MOVES, BEIS4/BELD6	CCNAA grid
Plume-in-Grid	Off	No large point sources in high-resolution CCNAA grid
In-line Ix emissions	On	Oceanic halogens
Chemistry		
Gas Phase Chemistry	CB6r5	Latest mechanism available
Aerosol Chemistry	Active	Gas phase only
Meteorological Interface	WRFCAMx v5.2	
Horizontal Diffusion	Smagorinsky	Spatially variant K-theory
Vertical Diffusion	YSU Kv formulation + KVPATCH	Minimum Kv 0.1 to 1.0 m^2/s
ACM2	Off	Non-local boundary layer convection
Sub-grid Cloud Convection	Off	
Deposition		
Dry Deposition	Zhang03	
Wet Deposition	On	rain/snow/graupel
Surface Chemistry Model	Off	
Bi-directional Ammonia	Off	For aerosol chemistry
Numeric Solvers		
Gas Phase Solver	Euler Backward Iterative (EBI)	Default fast and accurate solver
Vertical Advection	Piecewise Parabolic Method (PPM)	Default
Horizontal Advection	Piecewise Parabolic Method (PPM)	Default
Integration Time Step	Wind speed dependent	~0.5-1 min (4 km), 1-5 min (12 km), 5-15 min (36 km)
Super Stepping	On	Maximizes time step selection

Table 12-11. 2023 projected DVs at each monitoring site within the LVV according to SMAT-CE calculations using the 2016-2018 average base year DVs. Projected DVs are listed for the original 2023 future base case and for 2023 without contributions from wildfires. Green indicates values below the NAAQS while sites noted with an asterisk continued to exceed the ozone NAAQS in 2020, leading to the bump up from Marginal to Moderate nonattainment status.

Site ID	Site Name	2023 Future Base DV	2023 Future DV No Wildfires	Differences
		Avg 3x3	Avg 3x3	Avg 3x3
320030022	Apex	65.2	64.1	-1.1
320030023	Mesquite	57.2	56.5	-0.7
320030043	Paul Meyer*	67.7	65.8	-1.9
320030071	Walter Johnson*	67.9	65.6	-2.3
320030073	Palo Verde	67.2	64.9	-2.3
320030075	Joe Neal*	69.0	67.6	-1.4
320030298	Green Valley*	67.3	65.9	-1.4
320030540	Jerome Mack	64.1	62.4	-1.7
320030601	Boulder City	61.5	60.4	-1.1
320031019	Jean	63.9	62.2	-1.7
320032002	J.D. Smith	67.3	65.0	-2.3
320037772	Indian Springs	62.3	59.6	-2.7

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APPENDIX A: FUTURE YEAR SENSITIVITY MODELING

MEMORANDUM

Date: 31 October 2023

To: Zheng Li, Clark County DES/DAQ

From: Chris Emery, Trang Tran, Chao-Jung Chien, Tejas Shah

Subject: CBE NO. 606111-22: Clark County, Nevada Attainment Demonstration Modeling
Future Year Sensitivity Modeling

INTRODUCTION

In 2018, the US Environmental Protection Agency (EPA) designated a portion of Clark County, Nevada as a Marginal Nonattainment area under the 2015 ozone National Ambient Air Quality Standard (NAAQS) of 70 parts per billion (ppb) (Federal Register, 2018). The nonattainment boundary is defined as the Las Vegas Valley (LVV), hydrographic area 212 (HA 212), as recommended by the Nevada Division of Environmental Protection (NDEP) and Clark County (2018). Due to continued exceedances of the standard through 2020, the EPA reclassified the Clark County Nonattainment Area (CCNAA) to Moderate with an attainment date of August 3, 2024, based on the 2021-2023 8-hour ozone Design Value (DV) (Federal Register, 2022; 2023).

To support an ozone attainment demonstration for the Moderate CCNAA State Implementation Plan (SIP), Ramboll is conducting a complete photochemical modeling study and ancillary weight-of-evidence analyses. The Comprehensive Air quality Model with extensions (CAMx) is used for this purpose.

This memorandum describes CAMx future year sensitivity modeling scenarios and results from applying the modeled attainment test to project the 2016-2018 average DV to the 2023 future year. The methodology closely follows the approach described in EPA modeling guidance (EPA, 2018) and in the Modeling Protocol developed during the early phases of this project (Ramboll, 2022). A complete description of the Clark County CAMx modeling platform, results from 2016 base year performance evaluation and sensitivity testing, and results from the 2023 future year modeling applications are provided in the Technical Support Document (Ramboll, 2024).

Summary of Results

- We conducted a sensitivity test in which the 2023 future year model-ready <u>on-road</u> NOx emissions were scaled down by 50% within the CCNAA. All other emission sectors, emitted compounds, and other model inputs were unaltered from the 2023 future base case.
  - Projected 2023 DVs are all well below the ozone NAAQS but only 0-0.5 ppb lower than the DV projections from the 2023 future base case. The peak average projected DV is 68.5 ppb Joe Neal. Generally, these results are similar to the 15% VOC Rate of Progress scenario (Ramboll, 2024), but show NOx-disbenefit conditions in the urban center of the LVV and NOx-limited conditions in the

downstream rural areas to the north, consistent with OSAT analyses (Ramboll, 2024).

  - Spatial differences in projected 2023 DV relative to the 2023 future base case clearly show different chemical regimes in the LVV, with lower DV approaching -1 ppb in NOx-lean outer rural areas to the northwest and higher DV (NOx disbenefit) approaching 1 ppb in and around the NOx-rich urban core.

- We conducted a sensitivity test in which the 2023 future year model-ready non-road NOx emissions were scaled down by 50% within the CCNAA. All other emission sectors, emitted compounds, and other model inputs were unaltered from the 2023 future base case.
  - Projected 2023 DVs are all well below the ozone NAAQS but only 0-0.5 ppb lower than the DV projections from the 2023 future base case. The peak average projected DV is 68.5 ppb Joe Neal, as in the on-road NOx reduction case. While these results are also similar to the 15% VOC Rate of Progress scenario, this run suggests a slightly larger NOx-disbenefit condition in the urban center of the LVV than the on-road NOx reduction case.
  - Spatial differences in projected 2023 DV relative to the 2023 future base case again show different chemical regimes in the LVV, with lower DV approaching -1 ppb in NOx-lean outer rural areas to the northwest and higher DV (NOx disbenefit) approaching 0.4 ppb in and around the NOx-rich urban core.
- We conducted a sensitivity test in which Clark County emissions were held constant from 2016 to 2023 while emissions over the rest of the 12US2 and 36US3 domains evolved, thereby allowing us to characterize the effect that local emission changes between 2016 and 2023 have on the 2023 ozone projection.
  - All projected 2023 DVs in the "2016/2023 mix" hybrid scenario remain below the 70 ppb standard. Some sites show higher DVs and some lower relative to the 2023 future base case. The higher DVs in the hybrid case are an expected result since 2016 Clark County emissions are higher than in the 2023 future base case. The lower DVs at sites in and around the urban core show that higher 2016 emissions lead to lower ozone relative to 2023 emissions, i.e., a NOx disbenefit. Regional emission reductions on the 12US2 grid are key to reducing 2023 ozone in the LVV while a local NOx disbenefit condition in and around the core urban area mitigates those reductions to some extent.
  - Spatial differences in projected 2023 DV relative to the 2023 future base case clearly shows higher DV approaching 3 ppb in NOx-lean outer rural areas to the northwest and lower DV (NOx disbenefit) approaching -3 ppb in and around the NOx-rich urban core.
- We conducted a sensitivity test in which all 2023 future year model-ready anthropogenic NOx and VOC emissions were scaled down by 50% within the CCNAA. All other emission sectors, emitted compounds, and other model inputs were unaltered from the 2023 future base case.
  - Projected DVs are all lower than the 2023 future year base case. Reductions vary from 0.01 ppb at outer monitors to 1-3 ppb in central Las Vegas to almost 4 ppb at Joe Neal. Large reductions continue farther downstream to the northwest of the LVV. These results suggest that such deep cuts in both VOC and NOx are

sufficient to overcome the NOx disbenefit in central Las Vegas seen for smaller NOx-only reductions.

– Spatial differences in projected 2023 DV relative to the 2023 future base case exhibit deep ozone reduction patterns across the LVV. However, the vicinity of McCarran/Reid airport indicates higher ozone than the 2023 base case by several ppb. This is related to reducing McCarren airport NOx, which causes a very localized non-disbenefit. The 2016 base case and 2023 future case both generated a local ozone minimum at that location as a result of the large airport NOx emissions. Lifting that NOx burden in this scenario has filled in the ozone minimum because of a more efficient mix of NOx and VOC from the airport and other local sources in that area.

50% NOx REDUCTION TO ON-ROAD EMISSIONS

Emissions Processing

Model-ready 2023 on-road NOx (NO and NO_2) emissions were scaled by 50% over a rectangular subset of CC4c2 grid cells covering the CCNAA. This scaling was done for every day of the May-August modeling period. All other emission sectors, emitted compounds, and other model inputs were unaltered from the 2023 future base case. As a QA step, model-ready emissions were plotted to verify that only the CCNAA area of the CC4c2 grid was modified. Table 1 shows resulting CCNAA model-ready on-road emissions averaged over July weekdays.

Table 12. 2023 CCNAA model-ready July weekday average on-road emissions (TPD) and net change for the 50% NOx reduction sensitivity scenario.

Precursor	2023 Base	2023 50% NOx	Difference	Change (%)
NOx	18.60	9.30	-9.30	-50%
VOC	16.21	16.21	0.00	0%

CAMx Modeling

The 2023 future year base case CAMx run (Ramboll, 2024) was repeated but replacing 2023 on-road sector emissions on the CC4c2 grid with revised emissions reflecting 50% NOx reductions in the CCNAA. All other inputs were not modified, and only the 12US2/CC4c2 2-way nested grids were run using the 2023 12US2 future base case boundary conditions extracted from the 36US3 grid.

SMAT-CE Configuration

We applied SMAT-CE (EPA, 2022) identically to the original 2023 future base case scenario, specifying 2016-2018 3-year DV period for base monitored ozone (2014-2018 4^{th} highs centered on 2016). All other configuration options remained the same as the original SMAT-CE run, which employed default or standard settings throughout the setup menu. We made no special modifications to monitored data or specific selection of modeled days for the RRF calculation.

Results at Monitoring Sites

Table 2 shows projected DV results at monitoring sites that reported sufficient data during the 2016-2018 base year DV period. Projected DVs are all well below the ozone NAAQS but only 0-0.5 ppb lower than the DV projections from the 2023 future base case among sites within the CCNAA. The peak average projected DV is 68.5 ppb Joe Neal. Generally, these results are similar to the 15% VOC Rate of Progress scenario (Ramboll, 2024) as shown in Table 3. Note, however, that the 2023 ozone DV is unresponsive to the on-road NOx reduction at Paul Meyer and is higher at Green Valley, indicating VOC-limited, NOx-disbenefit conditions in the urban center of the LVV. Conversely, the DV reduction is largest at the downstream Indian Springs site well to the north, suggesting NOx-limited conditions in that rural area. These results are consistent with OSAT analyses (Ramboll, 2024) that indicate the modeled LVV environment represents a spatial mix of VOC- and NOx-sensitive conditions.

Table 2. 2023 projected DVs at each monitoring site within the LVV according to SMAT-CE calculations using the 2016-2018 average base year DVs. Projected DVs are listed for the original 2023 future base case and for the 2023 50% on-road NOx scenario. Green indicates values below the NAAQS while sites noted with an asterisk continued to exceed the ozone NAAQS in 2020, leading to the bump up from Marginal to Moderate nonattainment status.

Site ID	Site Name	2023 Future Base DV	2023 50% NOx DV	Differences
		Avg 3x3	Avg 3x3	Avg
320030022	Apex	65.2	65.0	-0.2
320030023	Mesquite	57.2	57.2	0.0
320030043	Paul Meyer*	67.7	67.7	0.0
320030071	Walter Johnson*	67.9	67.7	-0.2
320030073	Palo Verde	67.2	66.9	-0.3
320030075	Joe Neal*	69.0	68.5	-0.5
320030298	Green Valley*	67.3	67.4	0.1
320030540	Jerome Mack	64.1	64.0	-0.1
320030601	Boulder City	61.5	61.5	0.0
320031019	Jean	63.9	63.9	0.0
320032002	J.D. Smith	67.3	67.1	-0.2
320037772	Indian Springs	62.3	61.7	-0.6

Table 3. As in Table 2, but comparing projected DVs for the 2023 15% VOC ROP scenario and for the 2023 50% on-road NOx scenario.

Site ID	Site Name	2023 15% VOC ROP	2023 50% NOx DV	Differences
		Avg 3x3	Avg 3x3	Avg
320030022	Apex	65.2	65.0	-0.2
320030023	Mesquite	57.2	57.2	0.0
320030043	Paul Meyer*	67.5	67.7	0.2
320030071	Walter Johnson*	67.5	67.7	0.2
320030073	Palo Verde	66.9	66.9	0.0
320030075	Joe Neal*	68.8	68.5	-0.3
320030298	Green Valley*	67.1	67.4	0.3
320030540	Jerome Mack	64.0	64.0	0.0
320030601	Boulder City	61.5	61.5	0.0
320031019	Jean	63.9	63.9	0.0
320032002	J.D. Smith	67.1	67.1	0.0
320037772	Indian Springs	62.2	61.7	-0.5

50% NOx REDUCTION TO NON-ROAD EMISSIONS

Emissions Processing

Model-ready 2023 non-road NOx emissions were scaled by 50% over a rectangular subset of CC4c2 grid cells covering the CCNAA. This scaling was done for every day of the May-August modeling period. All other emission sectors, emitted compounds, and other model inputs were unaltered from the 2023 future base case. As a QA step, model-ready emissions were plotted to verify that only the CCNAA area of the CC4c2 grid was modified. Table 4 shows resulting CCNAA model-ready non-road emissions averaged over July weekdays.

Table 4. 2023 CCNAA model-ready July weekday average non-road emissions (TPD) and net change for the 50% NOx reduction sensitivity scenario.

Precursor	2023 Base	2023 50% NOx	Difference	Change (%)
NOx	23.10	11.55	-11.55	-50%
VOC	23.84	23.84	0.00	0%

CAMx Modeling

The 2023 future year base case CAMx run was repeated but replacing 2023 non-road sector emissions on the CC4c2 grid with revised emissions reflecting 50% NOx reductions in the CCNAA. All other inputs were not modified, and only the 12US2/CC4c2 2-way nested grids were run using the 2023 12US2 future base case boundary conditions extracted from the 36US3 grid.

SMAT-CE Configuration

We applied SMAT-CE identically to the original 2023 future base case scenario, specifying 2016-2018 3-year DV period for base monitored ozone (2014-2018 4th highs centered on 2016). All other configuration options remained the same as the original SMAT-CE run, which employed default or standard settings throughout the setup menu. We made no special modifications to monitored data or specific selection of modeled days for the RRF calculation.

Results at Monitoring Sites

Table 5 shows projected DV results at monitoring sites that reported sufficient data during the 2016-2018 base year DV period. Projected DVs are similar to the on-road NOx reduction case above and only 0-0.5 ppb lower than the DV projections from the 2023 future base case among sites within the CCNAA. This case, however, indicates a slightly larger NOx-disbenefit in the central urban core of the CCNAA. The peak average projected DV is 68.5 ppb Joe Neal, identical to the on-road NOx reduction case. Generally, these results are similar to the 15% VOC Rate of Progress scenario as shown in Table 6 but ozone is slightly higher in the NOx-rich areas around Paul Meyer, Walter Johnson, and Green Valley. Conversely, the DV reduction is largest at the downstream sites at Indian Springs, Apex, and Joe Neal as conditions become more NOx-limited. These results are again consistent with OSAT analyses that indicate the modeled LVV environment represents a spatial mix of VOC- and NOx-sensitive conditions.

Table 5. 2023 projected DVs at each monitoring site within the LVV according to SMAT-CE calculations using the 2016-2018 average base year DVs. Projected DVs are listed for the original 2023 future base case and for the 2023 50% non-road NOx scenario. Green indicates values below the NAAQS while sites noted with an asterisk continued to exceed the ozone NAAQS in 2020, leading to the bump up from Marginal to Moderate nonattainment status.

Site ID	Site Name	2023 Future Base DV	2023 50% NOx DV	Differences
		Avg 3x3	Avg 3x3	Avg
320030022	Apex	65.2	64.8	-0.4
320030023	Mesquite	57.2	57.2	0.0
320030043	Paul Meyer*	67.7	67.9	0.2
320030071	Walter Johnson*	67.9	68.0	0.1
320030073	Palo Verde	67.2	67.0	-0.2
320030075	Joe Neal*	69.0	68.5	-0.5
320030298	Green Valley*	67.3	67.4	0.1
320030540	Jerome Mack	64.1	64.0	-0.1
320030601	Boulder City	61.5	61.4	-0.1
320031019	Jean	63.9	63.9	0.0
320032002	J.D. Smith	67.3	67.1	-0.2
320037772	Indian Springs	62.3	61.6	-0.7

Table 6. As in Table 5, but comparing projected DVs for the 2023 15% VOC ROP scenario and for the 2023 50% non-road NOx scenario.

Site ID	Site Name	2023 15% VOC ROP	2023 50% NOx DV	Differences
		Avg 3x3	Avg 3x3	Avg
320030022	Apex	65.2	64.8	-0.4
320030023	Mesquite	57.2	57.2	0.0
320030043	Paul Meyer*	67.5	67.9	0.4
320030071	Walter Johnson*	67.5	68.0	0.5
320030073	Palo Verde	66.9	67.0	0.1
320030075	Joe Neal*	68.8	68.5	-0.3
320030298	Green Valley*	67.1	67.4	0.3
320030540	Jerome Mack	64.0	64.0	0.0
320030601	Boulder City	61.5	61.4	-0.1
320031019	Jean	63.9	63.9	0.0
320032002	J.D. Smith	67.1	67.1	0.0
320037772	Indian Springs	62.2	61.6	-0.6

2016 CC4C2 EMISSIONS WITH 2023 12US2 EMISSIONS

CAMx Modeling

The 2023 future year base case CAMx run was repeated but replacing all 2023 emissions on the CC4c2 grid with their 2016 counterparts. This run shows a hypothetical situation where Clark County emissions are held constant from 2016 to 2023 while emissions over the rest of the 12US2 and 36US3 domains evolve, thereby allowing us to characterize the effect that local emission changes between 2016 and 2023 have on the 2023 ozone projection. All other inputs were not modified, and only the 12US2/CC4c2 2-way nested grids were run using the 2023 12US2 future base case boundary conditions extracted from the 36US3 grid.

SMAT-CE Configuration

We applied SMAT-CE identically to the original 2023 future base case scenario, specifying 2016-2018 3-year DV period for base monitored ozone (2014-2018 4th highs centered on 2016). All other configuration options remained the same as the original SMAT-CE run, which employed default or standard settings throughout the setup menu. We made no special modifications to monitored data or specific selection of modeled days for the RRF calculation.

Results at Monitoring Sites

Table 7 shows projected DV results at monitoring sites that reported sufficient data during the 2016-2018 base year DV period. All projected DVs in the “2016/2023 mix” hybrid scenario remain below the 70 ppb standard. Some sites show higher DVs and some lower relative to the 2023 future base case. The higher DVs in the hybrid case are an expected result since Clark County emissions (maintained at 2016) are higher than in the 2023 future base case. The lower DVs at sites in and around the urban core show that higher 2016 emissions lead to lower ozone relative to 2023 emissions. This means that 2016 NOx emissions inhibit ozone formation in that area leading to a NOx disbenefit (higher ozone) when lower 2023 emissions are used. Since 2023 projected DVs are much lower than the 2016-2018 DVs in both cases at all sites, the wider regional emission reductions are key to reducing ozone in the LVV while a local NOx disbenefit conditions in and around the core urban area mitigates those reductions to some extent. These results are consistent with signals reported in the two sensitivity tests above, and with OSAT analyses that indicate the modeled LVV environment represents a spatial mix of VOC- and NOx-sensitive conditions.

Table 5. 2023 projected DVs at each monitoring site within the LVV according to SMAT-CE calculations using the 2016-2018 average base year DVs. Projected DVs are listed for the original 2023 future base case and for the 2016/2023 emissions mix scenario. Green DVs indicate values below the NAAQS while red differences indicate a NOx disbenefit signal.

Site ID	Site Name	2023 Future Base DV	2016/2023 Mix DV	Differences
		Avg 3x3	Avg 3x3	Avg
320030022	Apex	65.2	66.1	0.9
320030023	Mesquite	57.2	57.4	0.2
320030043	Paul Meyer*	67.7	67.1	-0.6
320030071	Walter Johnson*	67.9	67.2	-0.7
320030073	Palo Verde	67.2	67.4	0.2
320030075	Joe Neal*	69.0	69.3	0.3
320030298	Green Valley*	67.3	66.3	-1.0
320030540	Jerome Mack	64.1	63.7	-0.4
320030601	Boulder City	61.5	61.7	0.2
320031019	Jean	63.9	64.0	0.1
320032002	J.D. Smith	67.3	67.0	-0.3
320037772	Indian Springs	62.3	64.3	2.0

50% NOx AND VOC REDUCTION FOR ALL ANTHROPOGENIC EMISSIONS

Emissions Processing

Model-ready 2023 anthropogenic NOx and VOC emissions were scaled by 50% over a rectangular subset of CC4c2 grid cells covering the CCNAA. This scaling was done for every day of the May-August modeling period. All other emission sectors, emitted compounds, and other model inputs were unaltered from the 2023 future base case. As a QA step, model-ready emissions were plotted to verify that only the CCNAA area of the CC4c2 grid was modified. Table 6 shows resulting CCNAA model-ready anthropogenic emissions averaged over July weekdays.

Table 6a. 2023 CCNAA model-ready July weekday average anthropogenic NOx emissions (TPD) and net change for the 50% NOx reduction sensitivity scenario.

Sector	2023 Base	2023 50% NOx	Change (%)
afdust_adj	0.000	0.000	
airports_wo_McCarran_CD	8.386	4.193	-50%
fertilizer	0.000	0.000	
livestock	0.000	0.000	
nonpt	3.958	1.978	-50%
nonroad	23.097	11.555	-50%
np_oilgas	0.000	0.000	
onroad	18.603	9.301	-50%
pt_oilgas	0.151	0.075	-50%
ptegu	2.639	1.320	-50%
ptnonipm	5.938	2.969	-50%
rail	0.659	0.330	-50%
rwc	0.058	0.029	-50%
solvents	0.000	0.000	
airports_w_McCarran_CD	7.524	3.762	-50%

Table 6b. 2023 CCNAA model-ready July weekday average anthropogenic VOC emissions (TPD) and net change for the 50% VOC reduction sensitivity scenario.

Sector	2023 Base	2023 50% VOC	Change (%)
afdust_adj	0.000	0.000	
airports_wo_McCarran_CD	2.529	1.265	-50%
fertilizer	0.000	0.000	
livestock	0.002	0.001	-50%
nonpt	10.547	5.273	-50%
nonroad	23.843	11.928	-50%
np_oilgas	0.000	0.000	
onroad	16.212	8.106	-50%
pt_oilgas	0.020	0.010	-50%
ptegu	0.733	0.367	-50%
ptnonipm	0.585	0.293	-50%
rail	0.028	0.014	-50%
rwc	0.410	0.205	-50%
solvents	31.745	15.870	-50%
airports_w_McCarran_CD	0.098	0.049	-50%

CAMx Modeling

The 2023 future year base case CAMx run was repeated but replacing 2023 anthropogenic emissions on the CC4c2 grid with revised emissions reflecting 50% NOx and VOC reductions in the CCNAA. All other inputs were not modified, and only the 12US2/CC4c2 2-way nested grids were run using the 2023 12US2 future base case boundary conditions extracted from the 36US3 grid.

SMAT-CE Configuration

We applied SMAT-CE identically to the original 2023 future base case scenario, specifying 2016-2018 3-year DV period for base monitored ozone (2014-2018 4th highs centered on 2016). All other configuration options remained the same as the original SMAT-CE run, which employed default or standard settings throughout the setup menu. We made no special modifications to monitored data or specific selection of modeled days for the RRF calculation.

Results at Monitoring Sites

Table 7 shows projected DV results at monitoring sites that reported sufficient data during the 2016-2018 base year DV period. Projected DVs are all lower than the 2023 future year base case. Reductions vary from 0.01 ppb at outer monitors (Jean and Mesquite) to 1-3 ppb in central Las Vegas (Paul Meyer, Walter Johnson, Palo Verde, Green Valley, Jerome Mack and J.D. Smith) to almost 4 ppb at Joe Neal. Large reductions continue farther downstream to the northwest of the LVV (Indian Springs). These results suggest that such deep cuts in both VOC and NOx are sufficient to overcome the NOx disbenefit in central Las Vegas seen for smaller NOx-only reductions.

Table 7. 2023 projected DVs at each monitoring site within the LVV according to SMAT-CE calculations using the 2016-2018 average base year DVs. Projected DVs are listed for the original 2023 future base case and for the 2023 50% anthropogenic NOx and VOC scenario. Green indicates values below the NAAQS while sites noted with an asterisk continued to exceed the ozone NAAQS in 2020, leading to the bump up from Marginal to Moderate nonattainment status.

Site ID	Site Name	2023 Future Base DV	2023 50% NOx and VOC DV	Differences
		Avg 3x3	Avg 3x3	Avg
320030022	Apex	65.2	63.7	-1.5
320030023	Mesquite	57.2	57.1	-0.1
320030043	Paul Meyer*	67.7	65.7	-2.0
320030071	Walter Johnson*	67.9	65.0	-2.9
320030073	Palo Verde	67.2	64.4	-2.8
320030075	Joe Neal*	69.0	65.1	-3.9
320030298	Green Valley*	67.3	66.0	-1.3
320030540	Jerome Mack	64.1	62.4	-1.7
320030601	Boulder City	61.5	61.1	-0.4
320031019	Jean	63.9	63.8	-0.1
320032002	J.D. Smith	67.3	64.6	-2.7
320037772	Indian Springs	62.3	59.5	-2.8

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APPENDIX B: SENSITIVITY MODELING TO DERIVE AN INTER-POLLUTANT TRADING RATIO

MEMORANDUM

Date: 14 December 2023

To: Zheng Li, Clark County DES/DAQ

From: Chris Emery, Trang Tran, Chao-Jung Chien

Subject: CBE NO. 606111-22: Clark County, Nevada Attainment Demonstration Modeling
Sensitivity Modeling to Derive an Inter-Pollutant Trading Ratio

INTRODUCTION

This memorandum describes the approach to estimate a VOC:NOx inter-pollutant trading (IPT) ratio from two CAMx future year sensitivity modeling scenarios. The sensitivity runs involved applying across-the-board 10% NOx and 10% VOC reductions, relative to the 2023 15% VOC Rate of Progress (ROP) scenario, to all anthropogenic source sectors except airports within the Clark County Nonattainment Area (CCNAA or HA212). All other emissions sectors, emitted compounds, and other model inputs were unaltered from the 2023 15% VOC ROP case. Estimating an IPT ratio relative to the 15% ROP scenario considers the ambient chemical environment after all ROP measures have been fully implemented. For both sensitivity cases, the modeled attainment test procedure was used to project the monitored 2016-2018 average ozone Design Value (DV) to the 2023 future year. Ratios of resulting 2023 ozone DV impacts from the NOx and VOC cases relative to the 15% ROP case were calculated to yield the VOC:NOx IPT ratio for several combinations of monitoring sites within the CCNAA. A complete description of the Clark County CAMx modeling platform, results from 2016 base year performance evaluation and sensitivity testing, and results from the 2023 future year modeling applications are provided in the Modeling Technical Support Document.

Summary of Results

Following the approach summarized above, we determined ozone DV impacts from the 10% NOx and 10% VOC CCNAA anthropogenic emission reduction cases relative to the 15% ROP case. We then calculated a ratio of those DV changes normalized on a tpd basis to determine VOC:NOx IPT ratios for three different combinations of monitoring sites.

- <u>VOC:NOx IPT averaged over six monitoring sites within the CCNAA</u>: the IPT ratio is 0.08, meaning that it takes 0.08 tpd VOC for each 1 tpd of NOx to get an equivalent ozone impact; i.e., 1 tpd VOC reduction is ~12.5 times more effective at reducing ambient ozone concentrations than 1 tpd NOx reduction across the CCNAA (a VOC-limited, NOx-rich condition with NOx-disbenefits at three central locations).
- <u>VOC:NOx IPT averaged over three monitoring sites within the CCNAA (with no NOx-disbenefits</u>): the IPT ratio is 0.48, or 1 tpd VOC reduction is ~2 times more effective at reducing ambient ozone concentrations than 1 tpd NOx reduction among those sites.
- <u>VOC: NOx IPT at the peak Joe Neal site</u>: the IPT ratio is 0.75, or 1 tpd VOC reduction is ~1.3 times more effective at reducing ambient ozone concentrations than 1 tpd NOx reduction at that location.

EMISSIONS PROCESSING

Model-ready 2023 anthropogenic NOx and VOC emissions from the 15% ROP scenario were scaled down by 10% over a rectangular subset of CC4c2 grid cells covering the CCNAA. Estimating an IPT ratio relative to the 15% ROP scenario considers the ambient chemical environment after all ROP measures have been fully implemented. This scaling was performed for all anthropogenic sectors, except for airports, for every day of the May-August modeling period. All other emission sectors, emitted compounds, and other model inputs were unaltered from the 2023 15% ROP case. As a QA step, model-ready emissions were plotted to verify that only the CCNAA area of the CC4c2 grid was modified. Table 1 shows resulting CCNAA model-ready anthropogenic emissions averaged over July weekdays.

Table 13. 2023 CCNAA model-ready July weekday average anthropogenic emissions (tpd) and net change for the 10% NOx and VOC reduction sensitivity scenarios.

Precursor	2023 15% ROP	10% Reduction	Difference	Change (%)
NOx	55.10	49.59	-5.51	-10%
VOC	74.18	66.76	-7.42	-10%

CAMX MODELING

The 2023 15% ROP CAMx run (Ramboll, 2024) was repeated twice by replacing affected anthropogenic emissions on the CC4c2 grid with revised emissions reflecting 10% NOx and 10% VOC reductions in the CCNAA, respectively. All other inputs were not modified, and only the 12US2/CC4c2 2-way nested grids were run using the 2023 12US2 future base case boundary conditions extracted from the 36US3 grid.

SMAT-CE Configuration

We applied SMAT-CE (EPA, 2022) identically to the 2023 15% ROP scenario, specifying 2016-2018 3-year DV period for base monitored ozone (2014-2018 4th highs centered on 2016). All other configuration options remained the same as the original SMAT-CE run, which employed default or standard settings throughout the setup menu. We made no special modifications to monitored data or specific selection of modeled days for the relative response factor (RRF) calculation.

IPT Ratio Calculations

2023 ozone DV changes from the NOx and VOC cases relative to the 15% ROP scenario were determined at each monitoring site. Then, VOC:NOx IPT ratios were determined by normalizing the DV change by the total emission reductions (5.51 tpd NOx, 7.42 tpd VOC) produced by the 10% across the board emissions reductions. The resulting values represent the VOC:NOx IPT, which estimates the tpd of VOC for each 1 tpd of NOx to get an equivalent ozone DV impact.

$$VOC{:}NOx\ IPT\ ratio = \frac{\left[\dfrac{DV\ \Delta\ from\ NOx\ reduction\ (ppb)}{5.51\ NOx\ tpd}\right]}{\left[\dfrac{DV\ \Delta\ from\ VOC\ reduction(ppb)}{7.42\ VOC\ tpd}\right]} = \frac{VOC\ tpd)}{NOx\ tpd}$$

After calculating VOC:NOx IPT ratios for each monitoring site, we calculated several combinations as potential candidates for the VOC:NOx IPT ratio for the CCNAA:

- VOC:NOx IPT averaged over the six monitoring sites operating within the CCNAA in 2016 and 2023, to give a broad indication of precursor sensitivity across all simulated chemical regimes (JD Smith was excluded for purposes of calculating the future inter-pollutant trading ratio because the monitoring site shutdown in 2017 due to poor siting. It was replaced by Walnut Community Center which did not begin operating until 2021);
- VOC:NOx IPT averaged over three monitoring sites within the CCNAA with no NOx-disbenefits to give an average assessment in areas where NOx reductions are simulated to reduce ozone;
- VOC:NOx IPT at the peak Joe Neal site to estimate relative sensitivity for peak monitored ozone.

Table 2 shows results from the 2023 ozone DV changes and IPT ratio calculations for each site, and potential CCNAA VOC:NOx IPT ratios for the three combinations of monitoring sites. Note that SMAT only reports ozone DV projections to one decimal place, which is insufficient to calculate IPT ratios. However, SMAT also reports RRF to 4 decimal places, so we recalculated 2023 projected DVs at each monitor directly using RRFs reported by SMAT for the 15% ROP, 10% NOx and 10% VOC scenarios. The resulting DV differences from the NOx and VOC sensitivity cases relative to the 15% ROP DV were then calculated for each site. Table 2 shows the DV change at each monitoring site after modeling the emissions reductions and results of the VOC:NOx IPT calculations.

When considering all six monitoring sites within the CCNAA, the VOC:NOx IPT ratio is 0.08, meaning that meaning that it takes 0.08 tpd VOC for each 1 tpd of NOx to get an equivalent ozone impact. In other words, 1 tpd VOC emission reduction is 12.5 times more effective than 1 tpd NOx emissions reduction in reducing ambient ozone concentrations across the CCNAA, confirming a VOC-limited, NOx-rich condition with NOx-disbenefits at some central locations. Considering only three monitoring sites within the CCNAA with no NOx-disbenefits, the VOC:NOx IPT ratio is 0.48, or 1 tpd VOC reduction is ~2 times more effective than 1 tpd NOx reduction among those sites. At the peak Joe Neal site, the VOC:NOx IPT ratio is 0.75, or 1 tpd VOC reduction is ~1.3 times more effective than 1 tpd NOx reduction for reducing the ambient ozone concentration at that location.

Table 2. VOC for NOx tpd Inter-pollutant Trading Ratio based on 2023 projected DV change at each Clark County monitoring site according to SMAT-CE calculations using the 2016-2018 average base year DVs. Bold highlighted rows represent sites within the CCNAA. DV impacts in red indicate NOx-disbenefits where NOx reductions lead to ozone DV increases.

Site Name	2023 15% ROP DV (ppb)	10% NOx Reduction ΔDV (ppb)	10% VOC Reduction ΔDV (ppb)	ΔDV (ppb) / NOx (tpd)	ΔDV (ppb) / VOC (tpd)	VOC:NOx IPT Ratio
Apex	65.25246	-0.1476	-0.0562	-0.0268	-0.0076	3.53
Mesquite	57.23581	-0.0061	0.0000	-0.0011	0.0000	-----
Paul Meyer	67.50720	0.0576	-0.3024	0.0105	-0.0408	-0.26
Walter Johnson	67.58604	0.0217	-0.3543	0.0039	-0.0477	-0.08
Palo Verde	66.99318	-0.0868	-0.2675	-0.0157	-0.0361	0.44
Joe Neal	68.82000	-0.1800	-0.3225	-0.0327	-0.0435	0.75
Green Valley	67.13760	0.0994	-0.2201	0.0180	-0.0297	-0.61
Jerome Mack	64.02840	-0.0344	-0.1855	-0.0062	-0.0250	0.25
Boulder City	61.55160	-0.0396	-0.0264	-0.0072	-0.0036	2.02
Jean	63.90831	0.0000	-0.0137	0.0000	-0.0018	0.00
Indian Springs	62.25280	-0.2946	-0.0959	-0.0535	-0.0129	4.14
Average over all 6 CCNAA sites						0.08
Average over all 3 CCNAA sites <0 ΔDV						0.48
Joe Neal						0.75

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EPA, 2022. Photochemical Modeling Tools: SMAT-CE. https://www.epa.gov/scram/photochemical-modeling-tools.

EPA 2023. EPA Interpollutant Trading Technical Support Document Proposed Contingency Measures Federal Implementation Plan for the Fine Particulate Standards for San Joaquin Valley, California. U.S. Environmental Protection Agency, Region IX (July 2023).

Ramboll, 2024. Technical Support Document: Attainment Demonstration for the Clark County Ozone State Implementation Plan. Prepared for the Clark County Department of Environment and Sustainability, Division of Air Quality, Las Vegas, NV, by Ramboll Americas Engineering Solutions, Inc. Novato, CA (June 28, 2024).

ATTACHMENT C:

Control Technique Guideline
Reasonably Available Control Technology Analysis

Control Technique Guideline (CTG) Source Category Analysis for 2015 8-hour Ozone NAAQS Reasonably Available Control Technology (RACT) Requirements

togetherforbetter

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ACRONYMS AND ABBREVIATIONS

Acronyms

ACT	Alternative Control Techniques
AQR	Clark County Air Quality Regulations
CAA	Clean Air Act
CFR	Code of Federal Regulations
CTG	Control Technology Guideline
DES	Division of Air Quality
DES	Department of Environment and Sustainability
EPA	United States Environmental Protection Agency
FR	*Federal Register*
HA	Hydrographic Area
HAP	hazardous air pollutants
NAFB	Nellis Air Force Base
NAAQS	National Ambient Air Quality Standards
NEI	National Emissions Inventory
NESHAP	National Emission Standards for Hazardous Air Pollutants
NOx	nitrogen oxide(s)
NSPS	New Source Performance Standards
NSR	New Source Review
PET	polyethylene terephthalate
PTE	potential to emit
RACM	Reasonably Available Control Measures
RACT	Reasonably Available Control Technology
RTP	RTP Environmental Associations, Inc.
SIC	Standard Industrial Classification
SCC	Source Classification Codes
SIP	state implementation plan
SOCMI	Synthetic Organic Chemical Manufacturing Industry
TRI	Toxic Release Inventory
VOC	volatile organic compounds

Abbreviations

ft	foot
gal	gallon
l	liter
lb	pound
psi	pounds per square inch
tpd	tons per day
tpy	tons per year

EXECUTIVE SUMMARY

On January 5, 2023, the U.S. Environmental Protection Agency (EPA) reclassified Hydrographic Area (HA) 212 (Las Vegas Valley) in Clark County, Nevada, from a marginal to a moderate nonattainment area (88 FR 775). This reclassification triggered new state implementation plan (SIP) requirements for HA 212, including a requirement to "provide for implementation of reasonably available control technology (RACT)" for volatile organic compound (VOC) emissions from any stationary source category for which EPA issued a Control Technique Guideline (CTG) (42 U.S.C. 7502 & 7511a, §§ 172(c)(1) & 182(b)(2)).

This document summarizes research conducted by RTP Environmental Associates, Inc ("RTP") for the Clark County Department of Environment and Sustainability, Division of Air Quality ("DES"), and DES' conclusions based on that research.

RTP reviewed the point and nonpoint emissions inventory for HA 212 for the Clark County Department of Environment and Sustainability, Division of Air Quality (DES), along with business license information and minor and major New Source Review (NSR) permits, and conducted web searches to identify stationary sources that belong to CTG source categories. RTP conducted these searches for the source categories representing numerous EPA-issued CTGs.[1]

RTP made one of the following findings:

1. No stationary sources in the CTG source category operate within HA 212.

2. One or more stationary sources are operating within HA 212, and a CTG RACT rule is required for the category.

3. One or more stationary sources are operating within HA 212, and an existing SIP-approved RACT rule already provides for implementation of VOC RACT.

RTP determined that there are stationary sources operating within HA 212 for 11 CTG source categories. DES's existing rules already implement RACT for five of these categories, but new CTG RACT rules are needed for six CTG source categories. DES, however, elected to update existing regulations that apply to four CTG source categories to improve clarity or consistency with federal rules. DES submits a negative certification for the remaining CTGs because no stationary sources from the CTG source category operate within HA 212, based on the findings of the stationary source identification study.

[1] Some CTGs cover multiple source categories, while others update or add to requirements for previously issued CTGs. The dry cleaners CTG (EPA-450/2-78-050) applied to a solvent that EPA removed from the VOC air pollutant definition, so that CTG is no longer applicable. The general surface coating CTG (EPA-450/2-76-028) identified no specific source category, and EPA did not identify a presumptive RACT control level for this CTG or the automobile refinishing CTGs (EPA-450/3-88-009).

The source category for which DES already has a rule implementing RACT is surface coating of paper, which has only one source operating in HA 212. The four source categories for which DES elected to update existing rules are:

1. Gasoline loading terminals;
2. Bulk gasoline plants
3. Bulk gasoline terminals; and
4. Petroleum storage.

The six source categories for which DES will promulgate new CTG RACT rules are:

1. Metal and plastic parts surface coating;
2. Metal solvent cleaning (degreasing);
3. Industrial cleaning solvents;
4. Industrial adhesives;
5. Graphic arts (flexographic, offset lithographic and letterpress printing);
6. Cutback asphalt;

RTP estimates that the six new CTG RACT rules will result in 7.75 tons per day (tpd) of VOC emissions reductions. Gasoline service stations, and bulk gas plants and terminals are already subject to the CTG VOC RACT control level through requirements of other applicable rules. DES elected to include no emissions reductions credit for revising these rules, but may consider additional emissions reductions for these rules and other new CTG RACT rules in a future SIP actions for improved rule effectiveness estimates. Chapter 6 of this report summarizes RTP's findings.

1.0 INTRODUCTION

On June 4, 2018, the U.S. Environmental Protection Agency (EPA) designated a portion of Clark County (Hydrographic Area (HA) 212) as a nonattainment area for the 2015 8-hour ozone National Ambient Air Quality Standards (NAAQS) based on a design value that exceeded the 0.07 ppm standard (*Federal Register*, vol. 83, p. 25776 [83 FR 25776]). EPA classified the nonattainment area as "marginal." HA 212 is in a central location in the county and includes the Las Vegas Valley (Figure 1).

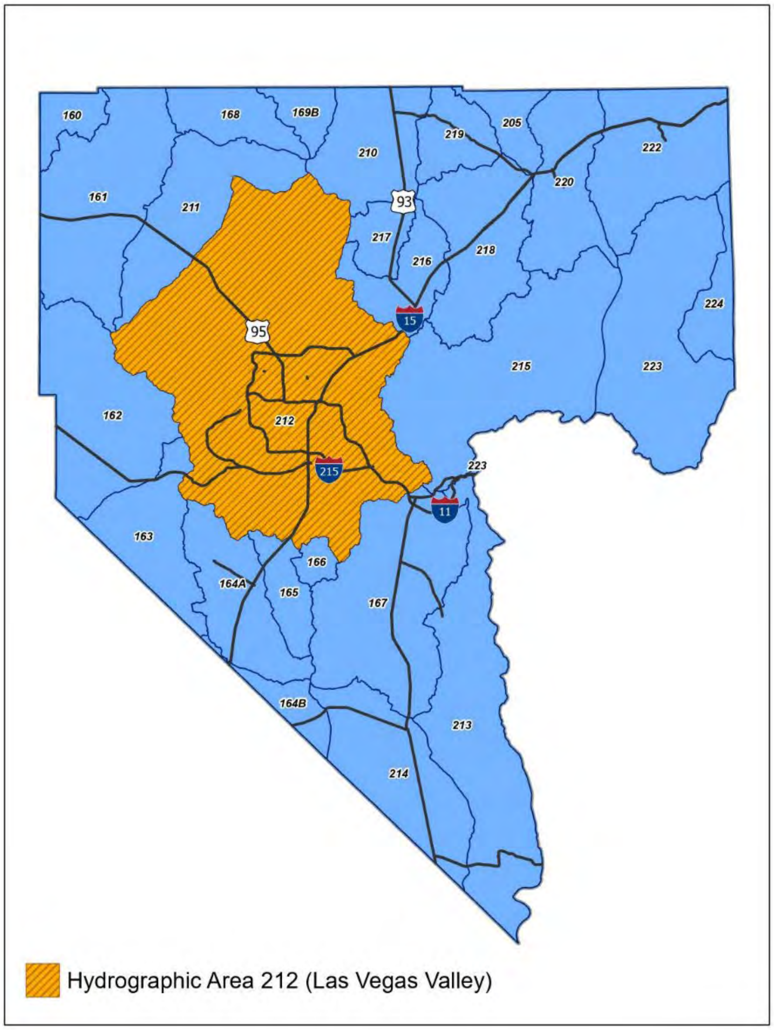

Figure 1. Nonattainment Area (HA 212) in Clark County, Nevada.

2.0 ATTAINMENT DATE REQUIREMENTS

The effective date of the nonattainment designation for HA 212 was August 3, 2018. EPA's implementation rule for the 2015 ozone NAAQS (40 CFR Part 51, Subpart CC) provides that a marginal nonattainment area must achieve attainment within three years of the effective date of the nonattainment designation. Accordingly, EPA required DES to bring HA 212 into attainment with the 2015 8-hour ozone NAAQS by August 3, 2021.

Whether HA 212 attained the NAAQS by the due date is based on the 2018–2020 design value. DES identified 28 exceedance days at area monitors during this period that it believes were caused by exceptional events, such as wildfires or stratospheric ozone intrusions. In accordance with EPA's exceptional events rule (40 CFR Part 50.14), DES submitted 17 exceptional event demonstrations that included data, modeling, and other information to EPA Region 9 to support excluding the monitoring data for these 28 events from the calculation of HA 212's ozone design value for the 2018–2020 ozone seasons.

After reviewing the data, Region 9 found the weight of evidence did not support a finding that emissions from exceptional events caused exceedances of the ozone NAAQS in HA 212 on June 19–20, 2018; May 6, 2020; May 9, 2020; June 22, 2020; and June 26, 2020 (88 FR 775). Region 9 deferred reviewing requests for data exclusion on other dates after determining that any findings on those dates would not affect a decision on HA 212's attainment status or qualification for a one-year extension for demonstrating attainment. When monitoring data for these dates is not excluded from design value calculations, HA 212's 2018–2020 design value equals 0.074 ppm. This value is above the 0.070 ppm design value required to demonstrate attainment of the 2015 8-hour ozone NAAQS (as required by 40 CFR Part 50.19) by HA 212's attainment date.

Under Section 181(b) of the Clean Air Act (CAA), EPA must reclassify a nonattainment area to the next higher ozone classification if the area fails to meet an attainment date (referred to as a "bump-up"). On July 22, 2022, EPA proposed to bump up HA 212 from marginal to moderate nonattainment (87 FR 43764); it finalized that finding on January 5, 2023 (88 FR 775).

This reclassification triggered additional state implementation plan (SIP) requirements for HA 212, including a requirement to impose reasonably available control technology (RACT) requirements on certain stationary sources. This document addresses the VOC RACT requirements for stationary sources that are part of a source category identified in one of EPA's Control Technique Guidelines (CTGs) (herein referred to as "CTG RACT").

3.0 REASONABLY AVAILABLE CONTROL TECHNOLOGY REQUIREMENTS

Under Section 182 of the Act, a moderate nonattainment area must apply RACT to reduce VOC emissions from each source category for which EPA issued a CTG. Sections 108 and 183 of the Act direct EPA to issue CTGs to provide air pollution control agencies with information on reducing VOC emissions from certain source categories, including emissions reduction benefits, cost of installation, and environmental impact of the control technology. EPA issued a total of 46 CTG documents: several CTGs address emissions control for more than one source category, while others update emissions control information addressed in older CTG documents.

In general, CTGs provide the "presumptive norm" for minimum VOC control requirements for specific categories of sources (44 FR 53761). Sources falling into a source category for which EPA has published a CTG are referred to as "CTG sources." EPA recommends that air pollution control agencies adopt regulations consistent with the applicability thresholds and control level in the CTGs; however, agencies have the freedom to "judge the feasibility of imposing the recommended controls on particular sources, and adjust the controls accordingly" (88 FR 62998).

CAA Section 182(b)(1)(A)(ii)(II) requires RACT for all major sources of ozone precursors, and Section 182(f) extends this major source requirement to NO_x major sources. For a moderate nonattainment area such as HA 212, "major source" is defined as a stationary source that emits, or has the potential to emit, at least 100 tons per year (tpy) of either VOC or NO_x.

EPA has not issued CTGs for NO_x emissions from source categories, so no RACT requirements apply to NO_x source categories because of an EPA-issued CTG. Instead, EPA issues Alternative Control Techniques (ACT) guidance for some NO_x source categories. ACTs do not establish a presumptive level of emissions control; rather, they provide information on potential control measures and costs. They are a resource for determining RACT for individual major sources and for Reasonably Available Control Measure (RACM) requirements, which are separate requirements under Section 172(c) of the Act.

EPA codified the RACT SIP requirements for the 2015 ozone NAAQS in its Ozone Implementation Rule (40 CFR Part 51, Subpart CC).[2] Because EPA bumped up HA 212 to a moderate classification for the 2015 8-hour ozone NAAQS, Clark County must now meet these RACT SIP requirements. This document discusses only the CTG RACT source obligations that DES considered for inclusion in the SIP; it does not address the major source NO_x and VOC RACT requirements.

Under EPA's RACT regulation and guidance, an air pollution control agency must adopt a CTG RACT rule if are CTG sources operating within the nonattainment area. The applicability thresholds differ based on the type of CTG source category but, in general and at a minimum, EPA excludes stationary sources emitting less than 15 lb/day (approximately 3 tpy) of VOC before consideration of emissions control from the CTG source categories.

If no stationary source would be subject to a given CTG RACT requirement, EPA accepts a negative declaration for that CTG source category. If a stationary source located in HA 212 emits VOC above the presumptive RACT applicability threshold, then DES may certify that an existing SIP regulation already satisfies CTG RACT requirements for the source category, if appropriate. If no current regulation applies to the source category or an applicable regulation does not meet presumptive RACT requirements, then DES must adopt a CTG RACT rule for the source category.

For each CTG, this document reviews available information to determine whether a stationary source within a CTG source category is operating within HA 212 and emitting above the presumptive RACT applicability threshold. When a new regulation is required to implement CTG RACT, this document provides an estimate of emissions reductions that could result from adopting the presumptive RACT recommended by EPA in the CTG.

4.0 METHODOLOGY

4.1 IDENTIFYING CTG RACT SOURCES

RTP employed four search methods to determine whether any stationary source within a CTG source category operated in the Clark County nonattainment area, including:

1. Reviewing emissions inventory information;

2. Searching business licenses obtained through the Secretary of State website and the Clark County Business License Office;

3. Consulting permitting and enforcement staff and permits issued for minor sources; and

4. Performing internet searches using key terms from the source category.

RTP used the emissions inventory prepared to support the moderate area Rate of Progress (“ROP”) demonstration” (“ROP Inventory”) (Ramboll 2024). This inventory includes both point source and nonpoint source emissions. If the ROP Inventory included emissions associated with a CTG source category at levels higher than a *de minimis* amount (3 tpy), DES concluded that a CTG RACT is needed for the CTG source category.

For business licenses, RTP downloaded and consolidated three databases from the Nevada Secretary of State website that contained license information for Las Vegas, North Las Vegas, and Henderson businesses. RTP added existing lists of known businesses in the dry cleaners, gasoline dispensing, printers, and surface coating source categories, along with businesses identified through “yellow pages” web searches. RTP conducted a geospatial screening to identify stationary sources located within HA 212.

Additional business information came from the Clark County Business License Office, but the locational screening was not reperformed after receiving this additional set of information. It is possible that some stationary sources on the master list do not operate within HA 212; further screening of identified stationary sources would be needed to verify source locations. For this iteration, the RTP conservatively assumed that all business licenses provided by the Clark County Business License Office operate in HA 212.

RTP screened each item on the master list to identify whether the business might fall within a CTG source category. To conduct this screening, RTP relied on business names, website searches, and license information. Section 5 provides information on stationary sources that could belong to a CTG source category. In some cases, RTP located information on a business in its minor source permitting database and used the permit to confirm the source was below CTG source applicability thresholds. This type of search, however, was not conducted for all CTG source category lists.

In some cases, no positive identification of CTG sources could be made from business licenses because there was no information on manufacturing methods and potential emissions. Accordingly, DES determined that inclusion of a business name on a potential CTG source list was not enough to determine a CTG RACT was necessary for a given source category. DES will continue to evaluate the information in the lists for future outreach efforts.

4.2 COMPARING EXISTING EMISSION CONTROL REQUIREMENTS TO CTG PRESUMPTIVE NORMS

RTP reviewed EPA's CTG for each source category with a confirmed operating source within HA 212. It then reviewed permits for the stationary source(s) and applicable federal and SIP regulations to determine whether the permit or regulations already required a level of VOC emissions reduction consistent with EPA's presumptive norm for the CTG source category.

Notably, SIP-approved Sections 12.1.3.6 and 12.4.3 of the Clark County Air Quality Regulations (AQRs) already require certain stationary sources to comply with RACT. Section 12.0 defines RACT as "the lowest emissions limitation that a particular source is capable of meeting by the application of control technology that is reasonably available, considering technological and economical feasibility." This RACT requirement applies when a stationary source proposes to construct or modify an emission unit and increase potential emissions (1) at a minor stationary source by greater than a significant rate, or (2) at a major stationary source by greater than the minor NSR significant level for a pollutant. For NO_x and VOC emissions increases, the significant levels are 20 tpy (AQRs 12.1.1 & 12.4.2.1). (These applicability thresholds, however, are generally higher than the presumptive applicability thresholds in EPA's CTGs.)

RTP estimated potential VOC emission reductions assuming the presumptive RACT level of control unless it determined a source or source category was already meeting the presumptive RACT level of control, in which case RTP assumed no additional emissions reductions.

4.3 RULE EFFECTIVENESS ADJUSTMENT

Rule effectiveness is an adjustment made to emissions factor estimates to reflect the degree of emissions reduction that is expected in practice. The adjustment factor recognizes that not all stationary sources will maintain compliance 100% of the time for a variety of reasons. EPA's initial rule effectiveness policy required a 20% default reduction in projected emissions reductions, unless the state or local agency could demonstrate a higher percentage was appropriate (52 FR at 45044, 45060). EPA subsequently revised this policy in 2005, following a workgroup process initiated in 2004 (EPA 2005).

The new policy recommends using a rule effectiveness adjustment that falls within one of five different ranges for point sources and one of three different ranges for nonpoint sources, depending on a variety of factors. The low end of the range of rule effectiveness requires at least a 30% adjustment to emissions projections and the high end requires no adjustment assuming 100% rule effectiveness.

Factors considered in selecting a range and then a specific value from within the range include the agency's experience enforcing the rule, degree of monitoring and reporting required, the frequency of inspections for the category, among others. These factors rely on data collected during past rule implementation. Where a state or local agency lacks information on a specific source category, EPA allows the agency to rely on studies conducted by other jurisdictions.

Applying this rule effectiveness policy to rules to a specific area without a compliance history presents a challenge because neither the agency nor sources have implementation experience from which data can be used to develop an appropriate adjustment factor. For purposes of projecting future emissions reductions that will result from the CTG RACT, DES considered its overall enforcement performance as reflected in EPA, Region 9's State Review Framework Study (EPA 2021a). This study audited DES' enforcement program for 2019.

EPA found that Clark County conducted all compliance inspections within the negotiated frequencies of every two years for Title V major sources, every three years for "Mega-sites", and every five years for other sources. EPA only identified 3 of 16 areas in which DES performed below the reported national average for a measurement metric. In other words, DES outperformed other jurisdictions on the audit greater than 80% of the time. These enforcement statistics support selecting a rule effectiveness value in the higher range for both point and nonpoint sources.

Each CTG Rule will also include a registration or permitting program, along with robust monitoring, recordkeeping, and reporting requirements to assure continuous compliance. This factor also points to selecting a rule effectiveness value from the higher range.

Nevertheless, DES recognizes that there are numerous considerations for deciding on a rule effectiveness value, for which DES simply lacks data. For example, DES lacks data associated with media publicity of enforcement actions, and sources have not yet developed their operator training programs for work practice standards for which data is available. In addition, EPA identified areas related to DES' identification and reporting of high priority violations (HPV) for which DES could improve inspector training and implementation.

Given the subjective nature of the rule effectiveness determination, and lack of complete data, unless otherwise explained in specific subsections of Section 5.0, DES elected to apply a 20% adjustment to estimated emissions reductions assuming 80% of the projected emissions reductions will be realized from the CTG Rule. This value is in Range 4 for point sources, and Range 2 for nonpoint sources, and likely under-estimates emissions reductions that will be realized in practice.

DES may re-evaluate these adjustments in a future SIP action and opt to increase the projected rule effectiveness supported by the enforcement audit or additional information.

5.0 CTG SOURCE CATEGORY REVIEW

The following sections discuss the results of DES's source identification analysis for four main groupings of EPA's CTGs:

1. Surface coating;
2. Solvent users;
3. Petroleum operations; and
4. Chemical compounds.

5.1 SURFACE COATING OPERATIONS

5.1.1 Aerospace Manufacturing and Rework Operations

CTG: Control of VOC Emissions from Coating Operations at Aerospace Manufacturing and Rework Operations (Aerospace CTG)

EPA Document Number: EPA-453/R-97-004

Conclusion:
DES submits a negative declaration for this CTG because there are no identified stationary sources in the Aerospace CTG source category operating within HA 212.

Discussion:
The Aerospace CTG, issued in 1997, recommends emissions controls for the manufacture, rework, and repair of aerospace vehicles and components when those operations have a potential to emit (PTE) VOC of greater than 25 tpy. Aerospace vehicles include airplanes, helicopters, missiles, rockets, and space vehicles. The CTG excludes regulation of rework operations involving space vehicles; rework operations performed on antique aerospace vehicles or components; research and development; quality control; laboratory testing; and electronic parts and assemblies (except cleaning and coating of completed assemblies).

The following SCC codes are associated with this source category:

- 40202401-99 Point Source – Aircraft
- 2401075000 Nonpoint Source: Surface Coating – Aircraft; Solvent – Industrial Surface Coating and Solvent Use

The 1997 NEI and the ROP Inventory contain no reported emissions for these SCC codes.

Nellis Air Force Base's (NAFB's) total VOC PTE from surface coating is 27.55 tpy (DES 2021). Over 7 tpy of the PTE, however, is associated with miscellaneous metal parts coating, not aerospace coating. NAFB operates seven spray operations for aerospace parts coating, and their total PTE is less than 20 tpy VOC. Therefore, Nellis Air Force Base is not subject to this CTG RACT because its PTE is below the presumptive RACT applicability threshold.

Using business licenses, RTP identified 6 businesses (one potentially operating in two locations) whose company name or website information implied they may engage in manufacture or rework of aerospace products, listed in Table 1.

Table 1. Businesses Potentially Engaged in Aerospace Surface Coating Operations

Name	Address	City	ZIP
AMW Precision	4120 W Windmill Ln #101	Las Vegas	89139
Apex Aviation	1410 Jet Stream Drive #100	Henderson	89052
CB Manufacturing Company	6500 W Sunset Rd	Las Vegas	89118
Dolphin Machine	2939 Brookspark Dr	North Las Vegas	89030
Dolphin Machine	15 W Brooks Ave	North Las Vegas	89030
Progressive Alloy Steels Unlimited	6335 N Hollywood Blvd #130-135	North Las Vegas	89115
Textron Aviation	4511 W Cheyenne Ave	North Las Vegas	89032
Vegas Metal Finishing	55 W Mayflower Ave	North Las Vegas	89030

DES searched its minor stationary source records for these facilities. DES permitted AMW Precision LLC with a PTE of 6.4 tpy VOC, but terminated its permit in 2015. None of the remaining sources hold minor source permits or Part 70 Operating permits. Each facility's VOC PTE is below the Aerospace CTG applicability threshold (25 tpy), so they are not part of the CTG source category.

5.1.2 Automobiles and Light-Duty Trucks Manufacturing and Rework Operations

CTG: Control of Volatile Organic Emissions from Existing Stationary Sources—Volume II: Surface Coating of Cans, Coils, Paper, Fabrics, Automobiles, and Light-Duty Trucks (multicategory CTG)

EPA Document Number: EPA-450/2-77-008

CTG: Control Techniques Guidelines for Automobile and Light-Duty Truck Assembly Coatings (Vehicle CTG 1)

EPA Document Number: EPA-R-08-006

CTG: Reduction of Volatile Organic Compound Emissions from Automobile Body Refinishing (Vehicle CTG 2)

EPA Document Number: EPA-453/R-94-031

Conclusion:

DES submits a negative declaration for these CTGs because there are no identified stationary sources in the source categories operating within HA 212.

Discussion:
EPA issued the first of three CTGs for the automotive industry in 1977, which contained RACT recommendations for both the automotive industry and other source categories. EPA followed this multi-category CTG with another CTG specific for automotive and light duty truck assembly coating and then the Vehicle CTG 2 in 2006. All CTGs recommend emissions controls for surface coating operations at vehicle assembly plants that manufacture passenger cars with a 12-person capacity or less and/or light duty trucks rated at 8,500 lb. or less and have emissions exceeding 15 lb/day before emissions controls. The CTGs apply only to new automobile manufacturing, not autobody collision repair shops or other rework facilities.

The following SCC codes are associated with this source category:

- 40201601-32 Point Source: Surface Coating –Auto & Light Trucks
- 40201699 Point Source: Surface Coating – Auto & Light Trucks, Not Otherwise Classified

RTP located four point sources reporting emissions under an associated SCC code in the ROP Inventory listed in Table 2.

Table 2. Vehicle Surface Coating VOC Emissions in ROP Inventory

Facility Name	Facility ID	Description	SCC	2017 Summer Weekday (tpd)	2026 Summer Weekday (tpd)
Republic Services Transfer Station	1087	Spray painting booths	40201601	0.0132	0.0132
Manheim Nevada	15839	Paint booth	40201601	0.0121	0.0121
Ritchie Brothers	16172	Paint booth	40201601	0.0026	0.0026
Shelby American	17347	Spray booth	40201606	0.0042	0.0044

None of these facilities, however, are engaged in the assembly of auto and light duty trucks. The Republic Services Transfer Station performs rework painting; Manheim Nevada and Ritchie Brothers perform automobile retouching as part of auction house services; and Shelby American modifies already assembled Ford Mustangs. Moreover, all four facilities' daily emissions are far below the CTG's 15 lb/day VOC applicability threshold. RTP's search located no business licenses for facilities engaged in assembly of autos and light-duty trucks, and a web search of U.S. automobile manufacturers showed no assembly plants within Clark County. While the nonpoint source ROP Inventory includes emissions for the category, DES concludes that these emissions are not part of this source category and will be considered in the miscellaneous metal and plastic parts CTG source category.

Accordingly, there are no confirmed stationary sources in the Vehicle CTGs categories.

5.1.3 Automobile Refinishing

CTG: Reduction of Volatile Organic Compound Emissions from Automobile Refinishing (Auto Refinishing CTG)

EPA Document Number: EPA-450/3-88-009

Conclusion:
No CTG RACT rule is necessary for this source category because (1) EPA did not establish a presumptive RACT for this source category in a CTG, and (2) EPA's federal rule for auto refinishing coating manufacturers (40 CFR Part 59, Subpart B) supersedes this source category's requirement for RACT.

Discussion:
EPA published the auto refinishing CTG in 1988 to provide technical information on available techniques to reduce emissions through use of material replacement, higher transfer efficiency spray guns, and add-on emissions controls. Unlike other CTGs, in which EPA makes specific recommendations for RACT control levels, this CTG provides only an overview of potential emission reduction strategies for air pollution control agencies to consider in developing industry regulations. EPA promulgated its own federal rule to regulate this industry with RACT, so no CTG RACT rule is required.

5.1.4 Coils

CTG: Control of Volatile Organic Emissions from Existing Stationary Sources—Volume II: Surface Coating of Cans, Coils, Paper, Fabrics, Automobiles, and Light-Duty Trucks (multicategory CTG)

EPA Document Number: EPA-450/2-77-008

Conclusion:
DES submits a negative declaration for this CTG because there are no identified stationary sources in the Coils Surface Coating source category operating within HA 212.

Discussion:
EPA issued this multicategory CTG in 1977 with a compilation of CTG RACT recommendations for several source categories, including coils. The CTG establishes recommended emissions control levels for surface coating of flat metal sheets or strips that come in rolls or coils. EPA also codified a New Source Performance Standard (NSPS) for this category in 1982 (40 CFR Part 60, Subpart TT).

The following SCC codes are associated with this source category:

- 2401045000–2401045370 Nonpoint Source: Solvent – Industrial Surface Coating and Solvent Use; Metal Coil

- 40201803–40201899 Point Source: Solvent – Industrial Surface Coating – Metal Cans and Coils

RTP found no sources in the 1997 NEI or the ROP Inventory related to these SCC codes, nor did it find any sources that match the category through a business license search.

Accordingly, DES submits a negative declaration for this CTG source category.

5.1.5 Fabric

CTG: Control of Volatile Organic Emissions from Existing Stationary Sources—Volume II: Surface Coating of Cans, Coils, Paper, Fabrics, Automobiles, and Light-Duty Trucks (multicategory CTG)

EPA Document Number: EPA-450/2-77-008

Conclusion:
DES submits a negative declaration for this CTG source category because there are no identified stationary sources in the Fabric Surface Coating source category operating within HA 212.

Discussion:
EPA published recommended RACT requirements for Fabric Surface Coating operations in this multicategory CTG issued in 1977. Fabric surface coating involves applying coating to fabric, for example to impart a protective coating or waterproof the fabric. It does not include application of vinyl plasticol.

The following SCC codes are associated with this source category:

- 2401010000–10999 Nonpoint Source: Surface Coating Fabric
- 40201101–199 Point Source: Surface Coating Fabric

There are no nonpoint source emissions in the ROP Inventory for the Fabric Surface Coating source category. The ROP Inventory lists two point sources: McCarran (Reid) International Airport and the New York-New York Hotel & Casino (owned by MGM Resorts). Both facilities have emissions that are at least 40% below the CTG's 15 lb/day VOC applicability threshold for RACT, so the sources' VOC emissions fall below the CTG source category applicability threshold.

RTP located approximately 25 businesses in the custom apparel industry, which frequently use vinyl graphics to decorate fabric. But these emissions are low and unlikely to exceed a de minimis value of 15 lb/day VOC. In addition, many operations are likely to be exempt from the CTG because it excludes the application of vinyl plasticol.

Accordingly, DES finds no confirmed stationary source in this CTG source category.

5.1.6 Flat Wood Paneling

CTG: Control of Volatile Organic Emissions from Existing Stationary Sources—Volume VII: Factory Surface Coating of Flat Wood Paneling (Flat Wood Paneling CTG 1)

EPA Document Number: EPA-450/2-77-008

CTG: Control Techniques Guidelines for Flat Wood Paneling Coatings (Flat Wood Paneling CTG 2)

EPA Document Number: EPA-453/R-06-004

Conclusion:
DES submits a negative declaration for this CTG because there are no identified stationary sources in the Flat Wood Paneling source category operating within HA 212.

Discussion:
EPA issued two CTGs for the Flat Wood Paneling source category, in 1977 and 2006. The CTGs establish presumptive RACT for production of prefinished wood construction products made from plywood, particleboard, and hardboard. Today, these products are often referred to as engineered woods. The first CTG established presumptive RACT requirements based on the length of material coated; the second established VOC per gallon limitations on coating materials and work practices for cleaning operations.

In the Flat Wood Paneling CTG, EPA identified businesses in the flatwood manufacturing industry as operating under Standard Industrial Classification (SIC) codes 2431, 2435, 2436, 2492, and 2499. EPA noted, however, that very few flat wood manufacturers perform coating operations in their plants.

The following SCC codes are associated with this source category:

- 2401015000 Nonpoint Source: Factory Finished Wood – All Solvent Types
- 40202101–99 Point Source: Coatings, Solvents, and Adhesives Flatwood Products

No point source emissions for the Flat Wood Paneling source category are included in the ROP Inventory, while the nonpoint source inventory includes only a *de minimis* level of emissions for 2026 (0.0088 tpd).

RTP identified two companies that advertise door manufacturing, listed in Table 3. As noted, few companies producing flat panel wood products operate surface coating operations at their manufacturing plants, and DES is not aware of any such facilities operating in HA 212. DES issued a permit to Panda Windows & Door Operations, but terminated it in 2014 due to low throughput and emissions below permitting thresholds (VOC PTE was listed as 0 tpy). The second facility also lacks a permit, presumably because emissions are below permitting thresholds.

Accordingly, DES concludes that neither source is part of this CTG source category and the nonpoint source emissions reporting in the inventory are *de minimis*.

Table 3. Businesses Potentially Engaged in Flat Wood Paneling Surface Coating Operations

Name	Address	City	ZIP	URL
Panda Windows & Doors Operations	3415 Bellington Rd	North Las Vegas	89030	Panda Windows and Doors
Solar Screen Factory	3560 Polaris Ave #41	Las Vegas	89103	Solar Screen Factory

5.1.7 Large Appliances

CTG: Control of Volatile Organic Emissions from Existing Stationary Sources—Volume V: Surface Coating of Large Appliances (Large Appliance CTG 1)

EPA Document Number: EPA-450/2-77-034

CTG: Control Techniques Guidelines for Large Appliance Coatings (Large Appliance CTG 2)

EPA Document Number: EPA 453/R-07-004

Conclusion:
DES submits a negative declaration for this CTG because there are no identified stationary sources in the Large Appliance source category operating within HA 212.

Discussion:
EPA issued two CTGs for the Large Appliance source category, in 1977 and 2007. In addition, EPA promulgated an NSPS for the source category in 1982 (40 CFR Part 60, Subpart SS) and a National Emission Standard for Hazardous Air Pollutants (NESHAP) in 2002 (40 CFR Part 63, Subpart NNNN). The CTG recommends VOC emissions control for paints, sealants, caulks, inks, adhesives, and maskants used in the appliance manufacturing industry that emit more than 2.7 tpy of VOC. The Large Appliance CTG source category covers manufacturers that surface-coat large appliances, including metal ranges, ovens, microwave ovens, refrigerators, freezers, washers, dryers, dishwashers, water heaters, and trash compactors manufactured for household, commercial, or recreational use, along with the parts associated with such products, including doors, lids, casings, panels, etc.

The following SCC codes are associated with this source category:

40201402–499	Point Source: Large Appliances – Surface Coating
2401060000	Nonpoint Source: Large Appliances – All Solvent Types

RTP located no emissions for the Large Appliance Category in either the 1997 NEI or the ROP Inventory. Through an internet search, RTP located two companies that may produce large appliances, listed in Table 4.

Table 4. Businesses Potentially Engaged in Large Appliance Surface Coating Operations

Name	Address	Description	URL
American Range Manufacturing Inc	4580 N Walnut Rd	Cooking equipment	American Range
Char Products LLC	2915 Losee Rd #106	Manufacturing	Char Appliances

DES conducted site visits at both facilities and determined that neither is part of the Large Appliance source category.

5.1.8 Magnet Wire – Surface Coating

CTG: Control of Volatile Organic Emissions from Existing Stationary Sources – Volume IV: Surface Coating of Insulation of Magnet Wire

EPA Document Number: EPA-450/2-77-033

Conclusion:
DES submits a negative declaration for this CTG because there are no identified stationary sources for the Magnet Wire source category operating within HA 212.

Discussion:
EPA published the CTG for the Magnet Wire source category in 1977. It recommends emissions control requirements for wire enameling, drying ovens, after varnish, and enamel applied to wire.

The following SCC codes are associated with this source category:

- 40201502 Point Source: Magnet Wire – Cleaning
- 40201531 Point Source: Magnet Wire – General
  40201503 Point Source: Magnet Wire – Mixing
- 40201504 Point Source: Magnet Wire – Storage
- 40201501 Point Source: Magnet Wire – Curing
- 40201505 Point Source: Magnet Wire – Cleanup
- 40201599 Point Source: Magnet Wire – Not Otherwise Classified

The 1997 NEI includes one point source emitting under SCC code 40201501: GE Transport, now owned by Wabec Industries. RTP reviewed the original permit application, the current permit application, and the emission inventory submissions, then DES reached out to the source to confirm whether activities at the source fall within the CTG source category; they do not. DES concludes that this stationary source does not operate a surface coating operation that falls under the Magnet Wire CTG source category. RTP identified one other potential emissions source for this source category, listed in Table 5; after investigation, DES found that emissions from this business are below the CTG applicability threshold.

Table 5. Businesses Potentially Engaged in Magnet Wire Operations

Name	Address	Description
Fi Car Audio, LLC	4535 W Russell Rd Ste 1	A/V equipment manufacturing—speaker systems manufacturing

5.1.9 Metal Cans

CTG: Control of Volatile Organic Emissions from Existing Stationary Sources—Volume II: Surface Coating of Cans, Coils, Paper, Fabrics, Automobiles, and Light-Duty Trucks (multicategory CTG)

EPA Document Number: EPA-450/2-77-008

Conclusion:
DES submits a negative declaration for this CTG because there are no identified stationary sources for the Metal Can source category operating within HA 212.

Discussion:
In 1977, EPA issued a multicategory CTG with a compilation of CTG RACT recommendations for several source categories, including Metal Cans Surface Coating. With respect to metal cans, this CTG requires emissions control for surface coating (both two- and three-piece fabrication). Specifically, the CTG recommends emissions controls for the application of sheet basecoat, over varnish, interior body spray, exterior end spray or roll coating, side seam spraying, and end sealing compound.

The following SCC codes are associated with this source category:

- 40201702–1799 Point Source: Surface Coating Metal Cans
- 402017–36 & 37 Point Source: End Sealing Compound
- 40201802–40201899 Point Source: Solvent – Industrial Surface Coating: Metal Cans
- 2401040000 Surface Coating: Metal Cans

The ROP Inventory contains no emissions for sources operating under these SCC codes.

After reviewing business licenses, RTP identified 10 businesses involved in manufacturing or bottling of beverages (such as water and soft drinks) that could involve metal can coating, listed in Table 6.

Table 6. Businesses Potentially Engaged in Metal Can Surface Coating Operations

Name	Address	City	ZIP
Aquatic CO.	201 N Meadow Valley Rd	Moapa	89025
Crystal Peaks, Inc.	1300 N Las Vegas Blvd	Las Vegas	89101

Graham Packaging PET Technologies, Inc.	875 American Pacific Dr.	Henderson	89014
Mr Alkaline Water	1263 E Silverado Ranch Blvd Ste Unit 109	Las Vegas	89183
Pepsi Las Vegas	6500 W Sunset Rd	Las Vegas	89118
Premium Waters Inc	3355 N Lamb Blvd	Las Vegas	89115
Purified Water To Go	4155 S Buffalo Dr Ste Suite 107	Las Vegas	89147
Reyes Coca-Cola Bottling LLC	230 N Mojave Rd	Las Vegas	89101
Wester Group Packaging	333 E Gowan Rd	N Las Vegas	89030
Wirtz Beverage Nevada	1849 W Cheyenne Ave	Las Vegas	89102

To further refine the list of potential CTG sources, RTP reviewed information available on company websites and in EPA's Air Toxic Release Inventory (TRI). Aquatic Co. is listed in EPA's TRI database as an emitter of styrene and methyl methacrylate, both associated with plastics manufacturing; therefore, DES concludes Aquatic Co. does not coat metal cans. Likewise, Graham Packing identifies as a polyethylene terephthalate (PET) plastic bottle manufacturer, and its website contains no information on metal can coating. Water To Go, Premium Waters, Inc., Wester Group Packaging, and Mr. Alkaline advertise use of only plastic and/or glass bottles. Wirtz Beverage Nevada lists itself as a distributor of fine wine, spirits, and beer, but describes no manufacturing activities.

One of the remaining bottling companies handles bottling for Pepsi-Cola. DES issued Pepsi-Cola a permit in 2013 documenting a VOC PTE of less than 1 tpy. DES determined that the remaining two facilities, one of which bottles for Coca-Cola, use bottles, not cans, in their operations.

In 2022, DES issued a construction permit to Real Estate Projects LLC for construction of an aluminum can manufacturing facility with surface coating operations. The company did not construct this facility and DES withdrew the permit.

After reviewing all available information, DES determined that there are no stationary sources operating metal can surface coating operations within HA 212.

5.1.10 Metal Furniture

CTG: Control of Volatile Organic Emissions from Existing Stationary Sources–Volume III: Surface Coating of Metal Furniture (Metal Furniture CTG 1)

EPA Document Number: EPA-450/2-77-032

CTG: Control Techniques Guidelines for Metal Furniture Coatings (Metal Furniture CTG 2)

EPA Document Number: EPA 453/R-07-005

Conclusion:
DES submits a negative declaration for this CTG source category because there are no identified stationary sources in the Metal Furniture source category operating within HA 212.

Discussion:
EPA issued two CTGs for the Metal Furniture industry, one in 1977 and another in 2005. EPA has also issued a NSPS: 40 CFR Part 60, Subpart EE–Standards of Performance for Surface Coating of Metal Furniture.

The following SCC codes are associated with this source category:

- 40202001–40202099 Point Source: Metal Furniture
- 2401025000 Nonpoint Source: Metal Furniture:

RTP identified no point source emissions in the ROP inventory reported for metal furniture operations. For nonpoint sources, the ROP Inventory includes 0.1763 tpd of VOC emissions. One furniture company, identified through the yellow pages, Urban Wood & Steelworx, includes metal in its name and its website shows furniture with mixed media. This company, however, identifies itself as a "custom" furniture maker, and produces furniture in low volumes that would fall below a reasonable applicability threshold for regulation of VOC from this source category. (Many states, for example, exempt sources with emissions between 10–100 tpy VOC PTE from compliance with state regulations for this CTG source category.)

Having identified no stationary source that would fall into this category after reviewing minor source permits, inspection records, and conducting internet and yellow page searches, RTP further reviewed the estimation methodology EPA used to project emissions for this source category. EPA relied on national sales data distributed to local areas based on population growth projections. This methodology simply assumes sources operating in the area rather than confirming presence of the industry.

To further explore the possibility of metal furniture manufacturing businesses operating in HA 212, RTP reviewed emissions inventory information from the 2020 NEI which posts slightly lower emissions for this category. For the 2020 NEI, EPA used employment data from the U.S. Census Bureau to estimate emissions. For SCC 2401025000 estimates, EPA used employment data from NAICS codes 337124, 337127, 337214, and 33215, rather than population growth projections (EPA 2020).

The NAICS association provides a NAICS and SIC crosswalk available for download at: https://www.naics.com/product/sic-naics-cross-references/. This crosswalk indicates that these NAICS codes cover industries operating under SIC codes 34, 38, 39 (as well as SIC 25). These SIC codes are included in the miscellaneous metal and plastic parts coatings CTG RACT rule. Accordingly, because RTP was unable to identify any metal furniture operations in HA 212, DES assumes that the emissions reported in the ROP inventory for Metal Furniture based on national sales data of surface coating materials reflect use of coating material in miscellaneous metal and plastic parts surface coating operations.

Accordingly, DES concludes that there are no verified source subject to this CTG operating within HA 212.

5.1.11 Miscellaneous Metal Part and Plastic Coating—Surface Coating

CTG: Control of Volatile Organic Emissions from Existing Stationary Sources–Volume VI: Surface Coating of Miscellaneous Metal Parts and Products (Metal and Plastic Parts CTG 1)

EPA Document Number: EPA-450/2-78-015

CTG: Control of Volatile Organic Emissions from Existing Stationary Sources–Volume VI: Surface Coating of Miscellaneous Metal Parts and Products (Metal and Plastic Parts CTG 2)

EPA Document Number: EPA 453/R-08-003

Conclusion:
DES will promulgate a CTG RACT rule to reduce emissions from the Metal and Plastic Parts source category.

Discussion:
In June 1978, EPA issued its first CTG document (1978 CTG) for controlling VOC emissions from surface coating of miscellaneous metal parts and plastic products. EPA issued another CTG in 2008. In January 1988, EPA promulgated an NSPS: 40 CFR Part 60, Subpart TTT–Standards of Performance for Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines. In February 1994, EPA issued an Alternative Control Techniques (ACT) document for controlling VOC emissions from surface coating of automotive and transportation plastic parts and business machine plastic parts. EPA also promulgated two NESHAPs relevant to this CTG source category: 40 CFR Part 63, Subpart MMMM–National Emission Standards for Hazardous Air Pollutants for Surface Coating of Miscellaneous Metal Parts and Products and 40 CFR Part 63, Subpart PPPP–National Emission Standards for Hazardous Air Pollutants for Surface Coating of Plastic Parts and Products.

The CTG applies to miscellaneous metal and plastic parts manufacturers that coat the parts produced and have VOC emissions greater than 3 tpy from use of paints, sealants, caulks, inks, and maskants. The category includes manufacturers producing such things as, but not limited to, fabricated metal products, molded plastic parts, small and large farm machinery, commercial and industrial machinery and equipment, automotive or transportation equipment, interior or exterior automotive parts, construction equipment, motor vehicle accessories, bicycles and sporting goods, toys, recreational vehicles, pleasure craft (e.g., recreational boats), extruded aluminum structural components, railroad cars, heavier vehicles, lawn and garden equipment, business machines, laboratory and medical equipment, electronic equipment, steel drums, and metal pipes.

The source category does not include stationary sources that are part of another CTG source category, such as architectural coatings (e.g., for steel bridges), automobile refinishing, fiberglass boats, and industrial adhesives. However, this CTG also applies to motor vehicle cavity wax, sealers, deadeners, gasket/gasket sealing material, underbody coatings, trunk interior coating, bedliners, and lubricating wax/compound used at a facility that is not an automobile or light-duty truck assembly coating facility.

The following SCC codes are associated with this source category:

- 40202201 Point Source: Surface Coating – Plastic Parts
- 40202501–04 Point Source: Surface Coating Operation – Misc. Metal Parts
- 40202532 Point Source: Surface Coating – Conveyor – Single Dip
- 40202531 Point Source: Surface Coating – Conveyor – Single Flow
- 40202535 Point Source: Surface Coating – Conveyor – Two Coat
- 40202533 Point Source: Surface Coating – Conveyor – Single Spray
- 40202434 Point Source: Surface Coating – Conveyor – Two Coat Flow and Spray
- 40202436 Point Source: Surface Coating – Conveyor – Two Coat Spray
- 40202505 Point Source: Surface Coating – Equipment Cleanup
- 40202437 Point Source: Surface Coating – Manual Spray and Air Dry
- 40202599 Point Source: Surface Coating – Other – Not Classified
- 40202510–12 Point Source: Surface Coating – Prime Coat
- 40202542–46 Point Source: Surface Coating – Single Coat Application
- 40202521–25 Point Source: Surface Coating – Topcoat Application
- 30303951 Point Source: Metallurgy Parts – Coatings to Sintered Parts
- 30303901–2 Point Source: Metallurgy Parts – Ovens
- 30901600–99 Point Source: Metal Pipe Coating of Metal Parts
- 30900301–04 Point Source: Abrasive Cleaning of Metal Parts
- 30901102–99 Point Source: Conversion Coating of Metal Products
- 2401025000 Nonpoint Source: Metal Furniture
- 2401065000 Nonpoint Source: Electronic and Electrical: SIC 36-363
- 2401090000 Nonpoint Source: Surface Coating: Misc. Manufacturing (SIC 33-39)
- 2401055000 Nonpoint Source: Machinery and Equipment: SIC 35
- 2401070000 Nonpoint Source: Motor Vehicles: SIC 371

- 2401075000 Nonpoint Source: Aircraft: SIC 372

As explained in Section 5.1.11, EPA allocated emissions for metal furniture coating based on nationwide sales and employment data related to NAICS codes that include industries operating under major group SIC codes 34, 38 and 39. Since RTP was unable to locate a metal furniture manufacturing operating in HA 212, DES assumes that any sales of metal coatings are associated with this category.

In addition to the nonpoint sources, there are four point sources from the ROP Inventory associated with the Metal and Plastic Parts Surface Coating source category, listed in Table 7.

Table 7. Metal and Plastic Part Surface Coating VOC Emissions in ROP Inventory

SCC	Facility	2017 Emissions Inventory (tpy)	2017 Summer Weekday Emissions (t/d)	2026 Summer Weekday Emissions (tpd)
40202201	Universal Urethane	7.88	0.0216	0.0216
40202201	Plasticard Locktech	10.64	0.0292	0.0292
40202501	Nellis AFB surface coating	1.400	0.0038	0.0051
40202501	Preferred Laminations -surface coating	4.410	0.0121	0.0121
2401065000	Electronic and Electrical	17	0.0458	0.0560
2401090000	Misc. Manufacturing	40	0.1087	0.1266
2401055000	Machinery and Equipment: SIC 35	-5-	0.0143	0.0165
2401070000	Motor Vehicles: SIC 371	-6-	0.0161	0.0193
2401075000	Aircraft: SIC 372	0.1095	0.0003	0.0004
2401025000	Metal Furniture	56.00	0.1522	0.1763
	TOTAL	**137.4395**	**0.4041**	**0.4631**

5.1.12 Other Potential Metal Parts or Plastic Coating Surface Coating Operators

Because this CTG source category affects numerous types of manufacturing operations, it could affect a variety of stationary sources. Table 8 lists businesses that might have operations subject to this CTG. In Section 5.2.2, which addresses the solvent metal degreasing source category, Table 13 lists stationary sources that deal with metal fabrication; sources in that table could also be subject to this CTG if they surface coat the fabricated metal.

Table 8. Businesses Potentially Engaged in Metal Parts or Plastic Coating Surface Coating Operations

Name	Address	Description
Bonaire USA LLC	3774 W Cheyenne Ave #100	Evaporative coolers
Builder's Best, Inc.	4975 N Pecos Rd	Vent hoods
Cart America, Inc.	4516 Mitchell St	Money carts

Name	Address	Description
Char Products LLC	2915 Losee Rd #106	Appliance manufacturing
Cole Kepro Int'l LLC	4170 Distribution Cir #103	Gaming units
Next Gaming LLC	4171 Distribution Cir #101	Game machine
Tri-Dim Filter Corp.	4980 Statz St #130 & 140	Air purifiers
American Range Manufacturing, Inc.	4580 N Walnut Rd North	Cooking equipment
Amigo Mobility International, Inc.	570 Corinthian Way	Wheelchairs
Ags LLC	6775 S Edmond St. #300	Slot machine maker
Ainsworth Game Technology, Inc.	5800 Rafael Rivera Way	Slot machine maker
Aristocrat Technologies, Inc.	3300 Birtcher Dr	Coin-operated gambling devices manufacturing
C B Tech	3101 Marion Dr #111	Hand and edge tool manufacturing - hammers, hand tools, manufacturing
Fi Car Audio LLC	4535 W Russell Rd #1	Audio and video equipment manufacturing - speaker systems manufacturing
Fortunet, Inc.	3901 Graphic Center Dr	Game machines
JCM American Corp.	925 Pilot Rd	Office machinery manufacturing - currency counting machinery manufacturing
SG Gaming, Inc.	6601 Bermuda Rd	Coin-operated gambling devices manufacturing
The Bright Group LLC	1660 Helm Dr #100	Slot machines manufacturing
Cannon Security Products	2895 W Capovilla Ave	Safes
Full Spectrum Laser LLC	6216 S Sandhill Rd	Laser cutting machines
Genesis Gaming Solutions, Inc.	1181 Grier Dr #G	Hardware for games
Genesis Gaming Solutions, Inc.	5845 Wynn Rd	Hardware for games
Paxiom Automation, Inc.	2037 E Maule Ave	Package machinery manufacturer
Promethium Limited	6885 Speedway Blvd #101	Design; unsure if manufacturer
Sabra Medtech LLC	6280 S Valley View Blvd	Surgical and wound care technologies
Shimadzu Scientific Instruments, Inc.	7102 Riverwood Drive	
Smart Bar USA LLC	7485 Dean Martin Dr #104	Automated cocktail dispenser manufacturer
Tamera Industries, Inc.	4350 Arville St #450	Barber shop and hair salon equip. manufacturer
Tamera Industries, Inc.	3325 W Oquendo Rd #B	Barber shop and hair salon equip. manufacturer
Varex Imaging Corporation	6811 Spencer St	X-ray machines
Zurety LLC	6160 N Hollywood Blvd #106	Appliance accessories
Creative Light Source, Inc.	4150 N Lamb Blvd #110	Lighting
LED Innovations, Inc.	5880 Wynn Rd	
Ardent Progressive Systems & Games LLC	2925 E Patrick Ln	Game maker

Name	Address	Description
Aruze Gaming America, Inc.	6900 S Decatur Blvd	Game maker
Sable Systems Int’l, Inc.	3840 N Commerce St	Medical appliances
Hovercam	6780 Paradise Rd	Teaching tools appliances
Integra Specialty Products, Inc.	3930 W Windmill Ln #100	Humid control product
Lift-All Company, Inc.	2629 E Craig Rd #K & L	
VSR Industries, Inc.	1937 Ramrod Ave	Manufacturing, assembly, and wholesale of slot machine cabinets

5.1.13 Projected Metal and Plastic Parts CTG RACT VOC Emissions Reductions

The CTG recommends specific pounds of VOC per gallon limitations for different coating types. (The list of recommended VOC coating limitations is extensive; consult the Metal and Plastics Parts CTG for more information on specific presumptive RACT recommendations.) EPA provides additional options for compliance through add-on emissions controls and work practices, estimating that compliance with recommendations for the Metal and Plastic Parts Surface Coating CTG would result in a 35% emissions reduction.

Nellis Air Force Base is already subject to VOC emissions limitations for surface coating in its Part 70 Operating Permit, and additional emissions reductions through RACT are unlikely. Accordingly, potential reductions are estimated for the remaining point and nonpoint source emissions assuming a 35% emissions reduction (Table 9). The 2026 summer day emissions are based on projections in the ROP Inventory. Additional emissions reductions from the Metal Parts CTG RACT could occur if additional sources are subject to the rule, but these emissions would not be credible in the attainment plan because they are not part of the ROP Inventory.

Table 9. Projected VOC Emission Reductions (tpd) from Metal and Plastic Parts Surface Coating Operations CTG RACT

Controllable 2026 VOC (tpy)	Control Efficiency	Rule Effectiveness	Projected Emissions Reductions (tpd)
0.46	35%	80%	0.13

5.1.14 Paper

CTG: Surface Coating of Paper (Paper Coating CTG 1)

EPA Document Number: EPA-450/2-77-008

CTG: Paper, Film, and Foil Coatings (Paper Coating CTG 2)

EPA Document Number: EPA 453/R-07-003

Conclusion:

DES certifies that existing SIP-approved regulations in Sections 12.1.3.6(b) & (c) and Section 12.1.4.1(f) meet the CTG RACT requirement for the only stationary source in this category operating within HA 212.

Discussion:
In 1977, EPA published a CTG for controlling VOC emissions from surface coating of paper, then issued an additional CTG in 2007 to recommend emissions control levels for paper, film, and foil coating. EPA also promulgated a 1983 NSPS (40 CFR Part 60, Subpart RR) and a 2002 NESHAP (40 CFR Part 63, Subpart JJJJ) that apply to paper coating operations. Paper Coating CTG 2 defines coating as "materials applied onto or impregnated into a substrate for decorative, protective, or functional purposes" (p. 17), applicable to an individual coating line that exceeds a VOC PTE of 25 tpy.

The following SCC codes are associated with this source category:

- 240103000–999 Nonpoint Source: Surface Coating – Paper, Foil and Film
- 40201399 Point Source: Surface Coating – Paper

Nonpoint source emissions in the ROP Inventory includes only *de minimis* emissions. There is one point source in the inventory: Catalina Plastic and Coating, now known as Nekoosa Coated Products, Inc. The Yellow Pages listing for this facility describes the company as a manufacturer of pressure-sensitive materials for the printing industry and window graphic film. Other products include pressure-sensitive vinyls, polyesters, acetates, and metalized films.[3] Its minor NSR permit describes the stationary source as operating under SIC code 3861, so this business includes operations within the Paper Coating CTG source category. Its VOC PTE is 29.11 tpy.

5.1.15 Other Potential Paper Coating Operators

RTP found one other facility that could have operations that fall under this source category: Sofidel America Corp. This business manufactures toilet paper and napkins and operates under SIC code 2679. Review of its minor NSR permit, however, shows that the stationary source has a VOC PTE of 0 tpy. Accordingly, DES concludes that this stationary source is not part of the Paper Coating CTG source category.

5.1.16 Potential Paper CTGs RACT VOC Emissions Reductions

The presumptive RACT for Paper Coating CTG 1 is 2.9 lb. VOC/gal. coating. The presumptive RACT for Paper Coating CTG 2 is even more stringent, requiring a 90% emissions reductions or 0.08 lb. VOC/lb. coating coupled with work practice requirements to minimize VOC emissions from cleaning materials.

[3] Yellow Pages website available at https://www.yellowpages.com/las-vegas-nv/mip/catalina-graphic-films-458743641 (accessed 8/10/2023).

Nekoosa operates three coatings lines. DES determined that two lines have a VOC PTE above 25 tpy that, when originally constructed, triggered a RACT requirement under Section 12.1. This rule requires Nekoosa to comply with a combined average VOC content limit restriction of 0.012 lb. VOC/lb. coating and 0.076 lb. VOC/lb. epoxy. In addition, Nekoosa must comply with work practice requirements that ensure storage of VOC-containing materials, including cloths and rags in closed containers, and must clean equipment in a manner that minimizes VOC emissions.

This RACT requirement for coatings is 6.0 orders of magnitude more stringent than EPA's presumptive RACT recommendation for coatings, and the epoxy VOC content limit is slightly more stringent. Accordingly, DES determined that SIP-approved Sections 12.1.3.6(b)–(c) and 12.1.4.1(f) of Clark County's existing SIP-approved rules "provides for the implementation of [RACT]" for this source category (42 U.S.C. 7502 § 172(c)(1)). Since Nekoosa is already complying with SIP-approved RACT requirements, no additional emissions reductions are creditable in the attainment plan.

5.1.17 Boat and Shipbuilding

CTG: Control Techniques Guidelines for Shipbuilding and Ship Repair Operations (Shipbuilding CTG)

EPA Document Number: 61 FR-44050 8/27/96

CTG: Control Techniques Guidelines for Fiberglass Boat Manufacturing Materials (Boat CTG)

EPA Document Number: EPA 453/R-08-004

Conclusion:
DES submits a negative declaration for these CTGs because there are no identified stationary sources in the Shipbuilding and Boat source categories operating within HA 212.

Discussion:
EPA issued the Shipbuilding CTG in 1996 through a *Federal Register* notice. This source category includes surface coating of pleasure craft, recreational boats, and yachts. EPA followed this CTG with a guideline specifically for boat manufacturing that applies to use of gel coats, resins, and materials used to clean application equipment in fiberglass boat manufacturing (which means manufacturing hulls or decks of boats or making molds to produce hulls or decks.)

The following SCC codes are associated with this source category:

- 40202302–399 Point Source: Large Ships Surface Coating
- 31401500–599 Point Source: Boat Manufacturing

RTP located no sources in the ROP Inventory associated with these SCC codes. After conducting web searches and reviewing lists of national shipbuilders (liquisearch.com), RTP located one business in Clark County that advertises the making of custom boat molds, but its principal business is pool and motorcycle/car repair (Table 10). DES concludes that its operations are not part of the CTG RACT source category, and emissions are below the 3 tpy VOC RACT applicability threshold.

Table 10. Business Potentially Engaged in Boat Manufacturing

Name	Address	City	ZIP
Kreative Industrial Fiberglass	4305 East Sahara Ave #27	Las Vegas	89104

5.1.18 Wood Furniture

CTG: Control of Volatile Organic Compound Emissions from Wood Furniture Manufacturing Operations (Wood Furniture CTG)

EPA Document Number: EPA-453/R-96-007

Conclusion:
DES submits a negative declaration for this CTG because there are no identified stationary sources in the Flat Wood Paneling source category operating within HA 212.

Discussion:
EPA finalized the Wood Furniture CTG in 1996 after negotiating the terms of the presumptive RACT recommended controls through a Federal Advisory Committee that included members from numerous stakeholder groups. The source category includes cabinet making (mass-produced and custom), household furniture (upholstered and non-upholstered), wood televisions, radios, phonographs, sewing machine cabinets, office furniture, and store fixtures that have a VOC PTE greater than 25 tpy.

The following SCC codes are associated with this source category:

- 40201901–999 Point Source: Wood Furniture – Solvent Utilization
- 2401015000 Nonpoint Source: Finished Wood – All Solvent Types
- 2401020000 Nonpoint Source: Wood Furniture – All Solvent Types

RTP located no point source emissions for the Wood Furniture CTG source category in the ROP Inventory, although RTP found businesses whose names or website description of services appeared related to woodworking. The nonpoint source emissions in the ROP Inventory includes 0.0088 tpy from the finished wood category and 0.1402 tpd from the wood furniture category.

EPA recommends applying the Wood Furniture CTG RACT only to stationary sources with a VOC PTE above 25 tpy. DES found minor source permits for only three stationary sources: Foloit Furniture Pacific, Inc., Preferred Laminations LLC, and Western Casework Corp. PTEs for all three stationary sources are below the 25 tpy presumptive VOC RACT applicability threshold. Accordingly, DES concludes that none of the businesses in the nonpoint source inventory or listed in Table 11 fall into the Wood Furniture source category.

Table 11. Businesses Potentially Engaged in Wood Furniture Surface Coating Operations

Name	Address	Description
Foliot Furniture Pacific Inc.	7000 Placid St	Institutional furniture manufacturing - furniture, institutional, manufacturing
Majestic Cabinets, LLC	4405 E Sahara Ave #5	Nonupholstered wood household furniture manufacturing - cabinets, wood household-type, freestanding, manufacturing
Old World Cabinetry LLC	3854 Silvestri Ln	Nonupholstered wood household furniture manufacturing - cabinets, wood household-type, freestanding, manufacturing
Palomares Cabinet Doors	4425 E Sahara Ave #28	wood television, radio, and sewing machine cabinet manufacturing - cabinets (i.e., housings), wood (e.g., sewing machines, stereo, television), manufacturing
Virtual Works	3130 Ponderosa Way	Upholstered household furniture manufacturing - furniture, household-type, upholstered on frames of any material, manufacturing
Dream Design Cabinets Inc	5480 S Valley View #130	
Greenline West LLC	6285 S Valley View #E	Architectural millwork
It Works Group LLC	7575 W Sunset Rd #170	
King Cabinets & Doors	4305 E Sahara #32	
Millrose Woodwork & Design	5071 Arville St	Wood product manufacturing
Pacific Custom Millwork, Inc.	7470 Dean Martin Dr #106	Millwork and cabinets
Pallet Broker LLC	6670 Gomer Rd	Pallets
Shallus Pen Company LLC	691 Lava Falls Dr	Wood pens
Som Wood Designs LLC	245 Toasted Almond Ave	
Urban Wood & Steelworx	6185 Harrison Dr #10	Custom
Wood Cab Factory LLC	6283 S Valley View Blvd #J	Wood cabinets
A & F Fine Wood Custom Cabinets	4504 W Diablo Dr #F-107	
A&A Custom Cabinets	4425 E Sahara Ave #35	
A. Sybz Cabinetry and Furniture LLC	4755 W Nevso Dr #14	
Angelo Cabinets Manufacturing LLC	6245 Harrison Dr #21	
Artistic Woodcrafters LLC	4545 W Reno Ave #B-7	
C&M Cabinet Pros	4305 E Sahara Ave #21	
Casey's Custom Woodworks LLC	4640 Arville St #C	
Cimmaron Drawer	4628 Industry Center Dr	Wood cabinets
CNC Associates NY LLC	3475 N Las Vegas Blvd	Cabinets
Flex Cabinetry	4019 Renate Dr	
Haddix Wood Interiors	4640 Arville St #C	
Haus of Reed, Inc.	3655 E Patrick Ln #800	Wood, metal
K & S Cabinets	3601 Highland Dr #4	
Las Vegas Cabinet Center	3871 S Valley View Blvd #5–7	

Name	Address	Description
Roble Woodworks LLC	4915 Steptoe St Ste #500	
RT Cabinets LLC	1951 Beesley Dr	
Somers Furniture LLC	3955 W Sunset Rd #101	
Sunny's Cabinets	3775 W Teco Ave #1	
Thorp Cabinetry & Millwork LLC	4230 W Teco Ave	
Vegas Pallet Co.	6175 N Hollywood Blvd	
Affirming Kitchen Clarity, Inc.	3845 Mapleview Ct	
All About You Custom Cabinet Company	4280 W Windmill Ln #102	
All American Design Center	3675 Highland Dr #10–12	
Artesia Kitchen & Bath	2972 S Rainbow Blvd #B	
Cabinets & Related Products, Inc.	1421 E Sunset Rd #2	
Creative Closets & Cabinetry LLC	4145 W Dewey Dr	
Custom Closet Systems, Inc.	5686 La Costa Canyon #100	
Cutting Edge Cabinets, Inc.	4910 E Cartier Ave	
EZ Roll-Out Drawers Ltd.	3775 W Teco Ave #8	
Generations Millwork LLC	5335 Wynn Rd	
GLM Cabinets	7930 W Warm Springs #170	
Grand China Materials Wholesaler, Inc.	4500 Wynn Rd #A	
Heather Allen Design Group	5275 S Arville #372	
Kitchen Connection LLC	6448 Windy Rd	
Kitchenland, Inc.	6455 Dean Martin Dr #K	
Lanz Cabinet Shop, Inc.	3025 W 7th Pl	
LV Cabinets World LLC	4350 Arville #300	
Nevada Custom Cabinets, Inc.	2712 Abels Ln	
Pacific Showcase	4555 Procyon St	
Preferred Laminations LLC	4701 Cameron St #F	
R & M Custom Woodworking	2960 Westwood Dr #19	
Sendero Cabinets & Lamination LLC	2520 E Sunset Rd #4	
Stellar Woodwerks LLC	2565 Chandler Ave #11 & 12	
Superior Custom Cabinets LLC	3600 S Highland Dr #18	
Two Magic Cabinets LLC	5115 Dean Martin Dr #506	
Unique Woodworking	4755 W Nevso Dr #9	
Monte Cabinets & Countertops	2257 Gowan #100	Cabinets
4 U Cabinet Makers LLC	3070 Sirius Ave #106	

Name	Address	Description
Absolute Closets and Cabinetry	6754 Spencer St	Wood kitchen cabinet and countertop manufacturing - cabinets, kitchen (except freestanding), stock or custom wood, manufacturing
Castle Cabinets, Inc.	3806 Civic Center Dr	
Creative Cabinetry LLC	2901 Highland Dr #9A	Custom cabinet and refinishing
JG Fine Custom Cabinetry LLC	4550 Donovan Way #124	
JJ Cabinets Millwork & Design	2901 Highland Dr #12B	Custom cabinets
Jacob's Cabinet Shop	2107 Western Ave	
JZL Designs, Inc.	2450 Losee Rd #G	Custom cabinets
JZL Designs, Inc.	2446 Losee Rd #8–11	Custom cabinets
Kitchen Podular LLC	5845 S Valley View Blvd	Modular kitchens
Knight Builders, LLC	4865 Statz St	
Las Vegas Cabinet	2901 Highland Dr #2E	Cabinet maker
Lioher Enterprise Corp	4060 Frehner Rd #100	Furniture
Mastercraft Woodworks	1733 Stocker St	Furniture
Progressive Cabinet Corp	553 W Sunset Rd	Miscellaneous - cabinet manufacturing/lamination of gaming cabinets
Rt Cabinets LLC	1711 Stocker St	
Siena Cabinets, Inc.	1222 Wigwam Pkwy	Manufacturer of cabinets
Western Casework Corporation	4832 Berg St	Commercial cabinets and millwork
Blue J Upholstery	520 W Sunset Rd #9	Auto, marine, and furniture upholstery
Safari Custom Upholstery	660 Middlegate Rd	Upholstery - cars & boats, furniture, re-covering
GREEN VALLEY UPHOLSTERY	520 W Sunset Rd #2	
Nostalgia Hot Rods LLC	1180 Wigwam Pkwy #100	Vehicle upholstery - vehicle upholstery & car restoration
Pete's Auto Upholstery LLC	1251 American Pacific #112	Automotive upholstery repair
Ajovi Upholstery	3867 S Valley View Blvd #30	Upholstery
Amore Drapery & Upholstery	2470 Chandler Ave #8	Upholstery
Browns Upholstery	3599 Polaris Ave #4	Upholstery
Cisco's Custom Upholstery Services, Inc.	4405 E Sahara Ave #3	Upholstery
Designers Decor Inc	6240 Stevenson Way	Upholstery
Encore Upholstery & Design	3650 W Reno Ave	Upholstery
International Reupholstery Corporation of America	13407 N Cave Creek Rd	Upholstery
Nevada Upholstery & Design, Inc.	3675 Highland Dr #15	Upholstery
R T Drapery & Furniture, Inc	6012 Topaz St #3	Upholstery
Santa Barbara Upholstery/ Supply	3319 E Charleston Blvd	Upholstery
Upholstery Works	4080 W Desert Inn Rd W-116	Upholstery

Name	Address	Description
Vinyl Smith	3867 S Valley View Blvd #30	Upholstery
Wizard's Custom Interiors	4275 E Sahara Ave #26	Upholstery

5.2 SOLVENT USERS

5.2.1 Degreasing Operations – Solvent Metal Cleaning

CTG: Control of Volatile Organic Emissions from Solvent Metal Cleaning (Degreasing CTG)

EPA Document Number: EPA-450/2-77-022

Conclusion:
DES will promulgate a CTG RACT rule for the Degreasing source category because there are stationary sources with degreasing operations within HA 212.

Discussion:
In 1977, EPA issued the Solvent Metal Cleaning CTG, which recommends control of VOC emissions from cold cleaners, open top vapor degreasers, and conveyorized degreasers that use volatile solvents to clean metal parts. The presumptive RACT exempts conveyorized degreasers smaller than 2.0 m^2 of air/vapor interface and open top degreasers smaller than 1 m^2 of open area.

The following SCC codes are associated with this source category:

- 401400222 Point Source: Solvent – Degreasing
- 40100336 Point Source: Solvent – Degreasing – Cold Cleaning
- 40100308 Point Source: Solvent – Utilization – Degreaser – Cold Cleaner
- 40100399 Point Source: Solvent – Degreasing – Cold Cleaning
- 40100308 Point Source: Solvent – Degreasing – Cold Cleaning
- 2415000000 Nonpoint Source: Solvent – Degreasing – All Solvent Types

RTP located one point source in the ROP Inventory associated with SCC 40100336: Nellis AFB, emitting 0.0002 tpd VOC.

The ROP Inventory includes 0.6256 tpd VOC emissions for the nonpoint sources.

Table 12. Metal Solvent Degreasing VOC Emissions in ROP Inventory

SCC	Description	2017 Summer Weekday Emissions (tpd)	2026 Summer Weekday (tpd)

40100336	Degreaser	0.0002	0.0003
2415000000	Degreasing: All Processes/All Industries	0.63	0.6253
	Total	0.6302	0.6256

5.2.2 Other Potential Degreasing Operators

RTP located 177 companies involved with metal working – including fabrication, machining, coin making, tower construction, fence making, and miscellaneous other activities. Table 13 lists these companies. These businesses could operate degreasers as part of their operations and emissions from these degreasers may already be included in the nonpoint source ROP Inventory. Because of the number of potential stationary sources, DES will adopt a CTG RACT for this source category.

Table 13. Metal Fabrication Businesses Potentially Engaged in Operating Degreasers

Name	Address	City	ZIP
A & N Custom Fabrication Inc	3130 Ponderosa Way	Las Vegas	89118
AA-1 Plating	242 Sunpac Ave	Henderson	89011
Aardwolf Welding	8276 Tone St	Las Vegas	89123
Absolute Metals LLC	4145 Sobb Ave	Las Vegas	89118
Additec	4185 W Post Rd #A-B	Las Vegas	89118
Additive Manufacturing	5311 Severance Lane	Las Vegas	89131
Advanced Additive 3D LLC	675 Grier Dr	Las Vegas	89119
After Dark Kreations LLC	3855 S Valley View Blvd #34	Las Vegas	89103
AG & Associates Inc.	2954 Westwood Dr #D	Las Vegas	89109
Aksarben Metals, Inc.	4525 Delancey Dr	Las Vegas	89103
All American Finishing	6575 Harrison Dr #7	Las Vegas	89120
All American Finishing LLC	3070 Sirius Ave #108		89102
AMC Fabrication, Inc.	6165 Annie Oakley Dr #B	Las Vegas	89120
American Machine Corporation	1800 Industrial Rd #140		89102
American Metal Customs	2450 Losee Rd	NLV	89030
AMW Precision LLC	4120 W Windmill Ln #101	Las Vegas	89139
AR Iron	1425 Athol Ave	Henderson	89011
AR Power Coating and Media Blasting	1401 Athol Ave	Henderson	89011
Armtech, Inc.	4023 W Oquendo Rd	Las Vegas	89118
Artisan Iron Works	2121 Western Ave #6		89102
Artistic Wood and Iron Works LLC	774 Wallington Estate St	Las Vegas	89178
Arts and Metal Iron Works LLC	1713 Stocker St	NLV	89030
ASAP Fabrication	4720 Grand Canyon	Las Vegas	89129
ASAP Fabrication LLC	2056 Highland Ave	Las Vegas	89102
Bad Dogz Fab	6221 Valley Grove Ct	Las Vegas	89130
Bandilla Iron Works	2642 Westwood Dr		89109
Belzona	2415 Greens Ave	Henderson	89014
Beyond Fabrication LLC	4660 Berg St #100	NLV	89031
Brenelle Enterprises, Inc.	5429 S Decatur Blvd	Las Vegas	89118
CMC Economy Steel	4485 E Colton Ave	Las Vegas	89115

Name	Address	City	ZIP
C&D Mobile Welding Service		NLV	89110
Centerline Fabrication LLC	3520 W Oquendo Rd	Las Vegas	89118
CKI Locker LLC	4170 Distribution Cir #103	NLV	89030
Cole Kepro International LLC	4170 Distribution Cir #4170	NLV	89030
Cubicall LLC	580 W Cheyenne Ave #100	NLV	89030
Cueto Welding LLC	1555 Bledsoe Ln	Las Vegas	89110
Custom Power Coating	3300 Pollux Ave	Las Vegas	89102
Custom Power Coating	6276 S Sandhill Rd	Las Vegas	89120
D.R. Mobile Welding Service	2590 N Nellis Blvd	Las Vegas	89156
Desert Sheetmetal Fabrication LLC	3475 Polaris Ave	Las Vegas	89102
DH Iron	2123 Western Ave #4	NLV	89102
Artistic Welding Iron	4300 N Pecos Rd #6	NLV	89115
Artistic Welding Iron LLC	4300 N Pecos Rd #6	NLV	89115
Elemetal Direct USA LLC	6280 S Valley View #630	Las Vegas	89118
Eteros Technologies USA, Inc.	6175 S Sandhill Rd #600	Las Vegas	89120
Fabricated LV LLC	6351 Hinson St #M	Las Vegas	89118
Fabrication Technologies, Inc.	7445 Dean Martin Dr #115-116	Las Vegas	89139
Fan Equipment Co., Inc.	2630 E La Madre Way	NLV	89081
Fiber-Tech Lifting Products	8740 S Jones Blvd	Las Vegas	89139
First Class Finishing	5686 La Costa Canyon	Las Vegas	89139
General Fabrication LLC	5225 S Valley View Blvd #6	Las Vegas	89118
Gilbert's Precision Machine	2685 Industrial Rd	Las Vegas	89109
GreenBroz, Inc.	6255 N Hollywood Blvd #115	NLV	89115
Ground Control Systems, Inc.	4650 Polaris Ave #A	Las Vegas	89103
H&H Enterprises	6340 Sunset Corporate Dr	Las Vegas	89120
H&H Enterprises	1965 E Russell Rd	Las Vegas	89119
Heads By Rick, Inc.	6959 Speedway Blvd #W108	Las Vegas	89115
Heavy Metal	1517 Industrial Rd	NLV	89102
Hershberger Bros Welding, Inc.	6625 W Gary Ave	Las Vegas	89139
Holdrite	4601 E Cheyenne Ave #101	Las Vegas	89115
Hybrid International LLC	235 W Brooks Ave	NLV	89030
Imperial Mobile Welding Services		NLV	89107
Industrial Metalcraft, Inc.	4715 W Harmon Ave	Las Vegas	89103
InteRebar Fabricators LLC	3101 E Craig Rd	NLV	89030
Intrepid Metal Works, Inc.	3321 Western Ave	Las Vegas	89109
Jackelope Machine LLC	3065 N Rancho Dr #164	NLV	89108
JC Custom Fabrication	6867 Speedway Blvd #R-104	Las Vegas	89115
JC Welding Service		NLV	89169
JNS Metals	3065 N Rancho Dr #176	NLV	89108
JR Metal Express, Inc.	4620 Mitchell St #A-B-C-D	NLV	89031
KC Ironworks LLC	3110 Polaris Ave #44	NLV	89102
Kwicksilver Nevada Wheel Repair	50 N Gibson Rd #150	Henderson	89014
L&J Fabrication LLC	3355 Clayton St #11	NLV	89032
Lanz Industrial Welding, Inc.	9310 NE 222nd Ave	Vancouver	98682
Las Vegas Fabrication Services	2900 E Patrick Ln #5A	Las Vegas	89120
Las Vegas Institute of Welding	4010 W Hacienda Ave #100	Las Vegas	89118
Las Vegas Machining Services	3073 S Highland Dr	Las Vegas	89109

Name	Address	City	ZIP
Lasher Sport LLC	5720 Arville St #105	Las Vegas	89118
Lefty's Metal Works LLC		NLV	89143
Line-X	7585 Commercial Way	Henderson	89011
LV Sheet Metal	4425 E Sahara Ave #10	Las Vegas	89104
LVL Custom Upholstery LLC	6295 Harrison Dr	Las Vegas	89120
Machining Specialist, Inc.	2542 Abels Ln	Las Vegas	89115
Magnus Ornamental Metals LLC	3850 Ponderosa Wy	Las Vegas	89118
Mario's Metal Shop, Inc.	3111 S Valley View #E-123	Las Vegas	89102
Matrix Metalworks LV LLC	6500 W Richmar Ave #400	Las Vegas	89139
Mel's Metal Works	5385 Cameron St #23	Las Vegas	89118
Metal Air Products, Inc.	3110 Westwood Dr	Las Vegas	89109
Metalwest - Henderson	451 Mirror Ct #104	Henderson	
Metro Awnings & Iron, Inc.	4525 W Hacienda Ave #2	Las Vegas	89118
Micar Fabrication & Design Co.	5166 Arville St	Las Vegas	89118
MKF LLC	6909 Fox Sparrow Ct	NLV	89084
My Iron Works LLC	4320 W Reno Ave #A	Las Vegas	89118
National Guard Products, Inc.	4584 Calimesa St	Las Vegas	89115
Nevada Metal Finishing Specialists Corporation	6658 Boulder Hwy #5	Las Vegas	89122
Nevada Precision Sheet Metal	3135 Venture Dr	Las Vegas	89101
Nevada Precision Sheet Metal	714 S 1st St	Las Vegas	89101
Nevada Precision Sheet Metal	3546 Procyon St	Las Vegas	89103
Nevada Sheet Metal Fabrication Services LLC	2806 Highland Dr	NLV	89109
Nevada Thermal Spray Technologies LLC	4842 Judson #115	Las Vegas	89115
Norsso LLC	6603 Schuster St	Las Vegas	89118
North Mobile Welding Reparations	3316 E Lake Mead Blvd	NLV	89030
Nova Tool Co.	3852 E Post Rd	Las Vegas	89120
Nucor Insulated Panel Group LLC	4700 Engineers Way #103	NLV	89081
Ohana Sheet Metal Fabrication	3050 Westwood Dr #A8	Las Vegas	89109
Omega Precision Machining	5460 Cameron St #101	Las Vegas	89118
P & L Fencing & Iron LLC	2842 Marco St	Las Vegas	89115
P & S Metal & Supply Company	5180 Rogers St	Las Vegas	89118
PDM Steel	4475 Alto Ave	Las Vegas	89115
Perfect Finish Coatings	6867 Speedway Blvd	Las Vegas	89115
Perfect Iron Works	3000 Builders Ave #C		89101
Phantom Refining	4020 W Ali Baba Lane #D	Las Vegas	89118
Plastic Media Stripping	4275 W Bell Dr #2	Las Vegas	89118
PM Steel		NLV	
Powder Coating Plus	5325 S Valley View #107	Las Vegas	
Power Coating Plus	3508 W Post Rd	Las Vegas	89118
Power Gen Components LLC	4311 W Oquendo Rd	Las Vegas	89118
Praxair Distribution Inc	4260 W Tompkins Ave #B	Las Vegas	89103
Precision Tube Laser LLC	6180 S Pearl St #F	Las Vegas	89120
Precision Works	2410 Western Ave	NLV	89102
Ram Pro Line LLC	4685 Copper Sage St #B	Las Vegas	89115
Ramsey & Son, Inc.	3292 E Sunset Rd #125 & 130	Las Vegas	89120

Name	Address	City	ZIP
Rebar Machine Service, Inc	5935 Emerald Ave	Las Vegas	89122
RioSteel LLC	6180 N Hollywood Blvd #107	Las Vegas	89115
Rolladen Rolling Shutters, Inc.	4405 Wagon Trail Ave	Las Vegas	89118
Roy Kueppers World of Magic	3867 S Valley View Blvd #27	Las Vegas	89103
Royal Wire Products, Inc.	4213 W Patrick Ln	Las Vegas	89118
RPM Fabrication	4985 Lincoln Rd	NLV	89115
SRI Instruments, Inc.	6440 Sunset Corporate Dr	Las Vegas	89120
SendIt CNC, Inc.	3945 W Reno Ave #D	Las Vegas	89118
Sewer Cable Equipment Company	2834 Marco St	Las Vegas	89115
Shamrock Metals LLC	1120 Palms Airport Dr	Las Vegas	89119
Shine Shop	676 Middlegate Rd	Henderson	89011
Sick Fab LLC	6160 N Hollywood Blvd. #104	Las Vegas	89115
Sierra Metals Southwest LLC	3555 W Oquendo Rd #C	Las Vegas	89118
Silver State Wire Rope and Rigging	8740 S Jones Blvd	Las Vegas	89139
Sin City Metal Works	4522 N Lamb Blvd	Las Vegas	89115
Slater Design Studios	1624 S Mojave Rd #140	Las Vegas	89104
SMS Industries LLC	6340 S Sandhill Rd #3	Las Vegas	89120
Southern Nevada Metal Fabricators	1235 N Nellis Blvd #15	NLV	89110
Southern Nevada Welding, Inc.	4115 Arctic Spring Ave	Las Vegas	89115
Spot On Fabrication	6151 McLeod Dr #E	Las Vegas	89120
SprayBuilt, Inc.	170 S Rainbow Rd	Las Vegas	89145
SRS Fabrication, Inc.	3031 Coleman St	NLV	89032
SRS Fabrication, Inc.	4560 Donovan Way	NLV	89031
Stainless Steel Fabrication, Inc.	2828 Highland Dr		89109
Steel Concepts LLC	9 E Brooks Ave	NLV	89030
Stephen McNair & Sylvia McNair	2235 Crestline Loop	NLV	89030
Sternschnuppe	3325 W Sunset Rd #E	Las Vegas	89118
Super Brands	151 Gallagher Crest Rd	Henderson	89074
Superior Duct Fabrication, Inc.	4050 W Mesa Vista Ave	Las Vegas	89118
Cutting Edge of Diamond Blades, Inc.	6285 Hinson St	Las Vegas	89118
The Tranzition	5470 Cameron St #108	Las Vegas	89118
Tiarra Iron Works	3580 Polaris Ave #7	Las Vegas	89103
Timet	245 Fourth St	Henderson	89015
Toms Welding		NLV	89108
Tri-State Steel, Inc.	2780 Bledsoe Ln	Las Vegas	89156
Trulite Glass & Aluminum	1513 A St		89106
UNI Metalworks	4425 E Sahara Ave #40	Las Vegas	89104
Union Erectors LLC	6625 W Gary Ave	Las Vegas	89139
Vegas Fastener Manufacturing	4315 W Oquendo Rd	Las Vegas	89118
Vegas Forge	4308 E Alexander Rd	Las Vegas	89115
Vegas Metal Finishing LLC	55 W Mayflower Ave	NLV	89030
Verdin Iron Works		NLV	89145
Vinny's Metal Fabrication	2446 Losee Rd #1 & 2	NLV	89030
VSR Industries, Inc.	1941 Ramrod Ave	Henderson	89014
Vulcan Iron	2237 Gowan Rd #170	NLV	89032
Welder UP LLC	3160 S Highland Dr #D	Las Vegas	89109
Wheel Repair Las Vegas Pros	676 Middlegate Rd	Henderson	89011

Name	Address	City	ZIP
Wizkits	5041 N Rainbow Blvd	NLV	89130
Wonder Iron Works	2616 Westwood Dr		89109
Young Engineering & Manufacturing, Inc.	4010 W Ali Baba Ln #G	Las Vegas	89118
Liborio's Sheetmetal Services, Inc.	2450 Losee Rd #F	NLV	89030
Metal Time, Inc.	595 E Brooks Ave #303	NLV	89030
Ray Iron Ornamental LLC	1735 Stocker St	NLV	89030

5.2.3 Potential Degreasing CTG RACT VOC Emissions Reductions

Presumptive RACT for this source category is based on equipment specifications and operating requirements rather than a specific emissions limitation. EPA recommends two options (equipment/operation specifications or work practices) for meeting RACT requirements for each type of degreaser system: cold cleansers, open top degreasers, and conveyorized degreasers.

Section 60.2 of the AQRs establishes requirements for degreasing operations; however, the Clark County Board of Commissioners withdrew this regulation in 2011 and DES can no longer enforce it. Because DES is not enforcing the rule the ROP Inventory is based on uncontrolled emissions.

For purposes of estimating emissions reductions, RTP included no additional emissions reductions from Nellis AFB because the facility is already subject to a RACT level of emissions control. For the remaining nonpoint source emissions, RTP estimated emissions reductions based on projected control efficiency.

Table 14 shows EPA's estimated control efficiency by percent of emissions reduction based on equipment type and control option. In the Degreasing CTG, EPA estimated that cold cleaners represent 60% of the equipment population, open top vapor degreasers represent 25%, and conveyorized degreasers represent 15%. However, information published by the Ozone Transport Commission suggests the population of cold cleaners is 92% (OTC 2016). DES staff confirmed they are unaware of any type of degreaser operating within HA 212 other than cold cleaners.

Table 14. Projected VOC Emissions Reductions (tpd) from Metal Solvent Degreasing CTG RACT

	Percentage of Degreaser Population	Option A	Option B	2026 Projected Emission Reductions (tpd)
Cold Cleaning	**100%**	50 ± 20%	53 ± 20%	0.33
Open Top Vapor Degreaser	**0%**	45 ± 15%	60 ± 15%	---
Conveyorized Degreasers	**0%**	25 ± 5%	60 ± 10%	---
Total Emissions Reduction				0.33

Note: All percentage reduction estimates based on values EPA reported in the Solvent Metal Cleaning CTG.

To compute the potential for emissions reduction that could result from adopting CTG RACT for solvent metal cleaning degreasers, DES assumed that all degreasers operating in HA 212 are cold cleaners. This assumption produced a more conservative emissions reduction estimate because estimated control efficiency for other types of degreasers are higher. If any open top or conveyorized degreasers operate within HA 212, the emissions reductions achievable with the CTG RACT would be higher.

Assuming a 100% population of cold cleaners, RTP multiplied the average control efficiency (53%) of Option B by the total degreasing emissions in the emissions inventory. This control efficiency assumption result also is conservative because DES's RACT will impose both Control Option A and Control Option B requirements, which should produce greater emissions reductions than would be achievable through application of only Control Option B.

Using this approach, RTP estimates that adoption of the Degreaser CTG RACT could reduce emissions by 0.33 tpd VOC (Table 14). DES made no adjustment for rule effectiveness because it used a highly conservative estimation approach, and the control efficiency estimates provided by EPA already included a wide efficiency range; adding another safety factor for rule effectiveness could produce highly skewed results.

5.2.4 Dry Cleaners

CTG: Control of Volatile Organic Emissions from Large Petroleum Dry Cleaners

EPA Document Number: EPA-450/3-82-009

Conclusion:
DES submits a negative declaration for this CTG because there are no confirmed stationary sources for the Large Petroleum Dry Cleaners source category within HA 212.

Discussion:
EPA issued a CTG in 2008 that applies to large dry cleaners using petroleum dry cleaning solvents. EPA does not define "large" in the CTG, but developed model plants for facilities with VOC emissions from 40 to greater than 140 tpy.

The following SCC codes are associated with this source category:

- 40100102 Point Source: Dry Cleaning
- 40100104 Point Source: Dry Cleaning
- 40100147 Point Source: Dry Cleaning

There are no nonpoint source emissions for this CTG source category because the source would need to emit at point source thresholds to qualify as a CTG source.

RTP identified no point sources in the ROP Inventory reporting emissions under these SCC. Through its business license search, RTP identified businesses registered as dry cleaners. The majority, however, are intake points for laundry processed elsewhere. None of the facilities hold Clark County air permits which means that all the facilities emissions are below the model plant levels EPA used for the CTG. Thus, none of the identified dry cleaners would qualify as a "large" dry cleaners.

5.2.5 Industrial Adhesives

CTG: Control Techniques Guidelines for Miscellaneous Industrial Adhesives (Industrial Adhesives CTG)

EPA Document Number: EPA 453/R-08-005

CTG: Control Techniques Guidelines for Miscellaneous Industrial Adhesives (Industrial Adhesives CTG)

EPA Document Number: EPA 453/R-08-005

Conclusion: DES will promulgate a CTG RACT rule for the Industrial Adhesive source category because there is at least one stationary source operating within HA 212.

EPA issued the Industrial Adhesives CTG in 2008. It applies to a range of adhesive applications that emit more than 3 tpy of VOC. Adhesives are generally defined as compounds that allow two surfaces to join, and the CTG recommends controls for a variety of adhesive and adhesive primer applications. It does not apply to processes addressed in other CTGs, such as aerospace coatings; metal furniture coatings; large appliance coatings; flat wood paneling coatings; paper, film, and foil coatings; offset lithographic printing and letterpress printing; flexible package printing; coil coating; fabric coating; and rubber tire manufacturing. The CTG includes recommendations for motor vehicle adhesives, glass bonding primers, and weatherstripping adhesives that are not applied at automobile and light duty truck manufacturers.

The following SCC codes are associated with this source category:

- 40200701 Point Source: Adhesive Application – Surface Coating
- 40200706 Point Source: Adhesive Mixing
- 40200707 Point Source: Adhesive Storage
- 40200710 Point Source: Adhesive General
- 40200711 Point Source: Adhesive Spray
- 40200712 Point Source: Adhesive Roll-on
- 30105101 Point Source: Animal Adhesives
- 30105001 Point Source: General/Compound Unknown
- 2460600000 Nonpoint Source: Adhesives and Sealants (consumer and commercial)

Table 15 shows emissions for one point source and nonpoint sources.

Table 15. Industrial Adhesives VOC Emissions in ROP Inventory

SCC	Facility	2017 Summer Weekday Emissions (tpd)	2026 Summer Weekday (tpd)
40200701	Erickson International	0.0054	0.0054*
2460600000	-------	5.7803	6.6003

Erickson International's actuals emissions are well below 3 tpy VOC recommended for presumptive RACT applicability and would not subject the stationary source to the Industrial Adhesives CTG if adopted.

5.2.6 Other Potential Industrial Adhesive Operators

Unlike other CTG source categories, which fall into a defined source category that can be identified through business licenses, industrial adhesives may be used by a variety of source categories. RTP identified two stationary sources whose business descriptions suggested the potential for industrial adhesive use. Neither stationary source is permitted through DES's minor NSR permit program. Thus, DES determined that emissions for these sources are below the RACT applicability threshold.

A review of minor NSR permits found that Universal Urethane, Inc. is a user of industrial adhesives, but its minor NSR permit (Source ID 859, last issued May 19, 2022) limits adhesive use to less than 2,000 lb/12-month rolling total. This falls outside the Industrial Adhesives CTG source category because emissions are less than 3 tpy of VOC. Review of a Part 70 operating permit for Certain Teed determined this manufacturer did not fall within the source category.

RTP identified Artesian Spas as an additional user of industrial adhesives; it has a PTE for primers, cements, and adhesives of 27.19 tpy of VOC, so falls within this CTG source category.

Table 16. Businesses Potentially Engaged in Industrial Adhesive Operations

Name	Address	Description	URL
Wausau Coated Products, Inc.	4030 Industrial Center Dr #501	Adhesive labels	Wasau Labels
Specialty Adhesive Film Co.	1914 Mendenhall Dr	Heat seal adhesive	Specialty Adhesive Film
Universal Urethane, Inc.	—	—	—
Artesian Spas	—	—	—

5.2.7 Projected Industrial Adhesives CTG RACT Emissions Reductions

EPA's presumptive RACT approach is based on two options for achieving emission controls: (1) use of low-VOC adhesives with good adhesive transfer application methods, and (2) a combination of low-VOC adhesives and add-on controls. Alternatively, EPA allows for an 85% control efficiency standard.

While the SCC code 2460600000 (nonpoint source) is assigned to consumer and commercial products rather than industrial products, EPA's 2017 National Emissions Inventory (NEI) technical support document indicates that estimated emissions could include point source emissions from SCC 40200710 (industrial adhesives) (EPA 2021b). Since RTP identified at least one point source with a VOC PTE above 27 tpy (0.074 tpd) whose emissions are not otherwise represented in the ROP Inventory, RTP'assumed 20% of SCC 2460600000's nonpoint emissions (1.3201 tpd) represent emissions from point sources potentially subject to the CTG. Table 17 shows RTP'semissions reduction estimates from point and nonpoint sources.

Table 17. Projected VOC Emissions Reductions from Industrial Adhesives CTG RACT

2026 Controllable Industrial Adhesive Emissions (tpd)*	Control Efficiency	Rule Effectiveness	2026 Projected Emissions Reductions (tpd)
1.32	85%	80%	0.90

Based on 20% of nonpoint source emissions.

5.2.8 Industrial Cleaning Solvents

CTG: Industrial Cleaning Solvents

EPA Document Number: EPA-453/R-06-001

Conclusion:
DES will promulgate a CTG RACT rule for the Industrial Solvent Cleaning source category because there likely is at least one stationary source operating within HA 212.

Discussion:
EPA issued the Industrial Cleaning Solvents CTG in 2006. The following SCC codes are associated with industrial solvent use:

- 40200201 Point Source: Water – Base Solvent – Utilization – General
- 40200301 Point Source: Varnish/Shellac Solvent – Utilization – General
- 40200401 Point Source: Lacquer Solvent – Utilization – General
- 40200501 Point Source: Enamel Solvent – Utilization – General
- 40200601 Point Source: Primer Solvent – Utilization – General
- 40200801 Point Source: General Solvent – Utilization – Surface Coating
- 40200901 Point Source: Solvent – Utilization – Thinning Solvents
- 40200926 Point Source: Solvent – Utilization – Thinning Solvents
- 40299998 Point Source: Solvent – Utilization – Misc.
- 40100308 Point Source: Methyl Ethyl Ketone

- 40200901 Point Source: Thinning Solvent
- 40200926 Point Source: Thinning Solvent
- 2401200000 Nonpoint Source: Other Special Purpose Coatings

Clark County's ROP Inventory includes no point source emissions. This finding is consistent with EPA's estimate in the 2006 Industrial Solvent Clean CTG which reported no sources in the state of Nevada. The ROP Inventory includes (0.7914) tpd of VOC emissions associated with "other special purposes coatings" which RTP assumes is related to this source category.
In reviewing the ROP Inventory, there are at least two SCC, identified in the following table, that include emissions from the use of cleaning solvents. The coatings and related products category SCC 2460500000 includes emissions formerly reported under SCC 246020000 (other industrial solvent utilization) in the 2016v2 modeling platform. To estimate the portion of emissions in the coatings and related products category in the ROP Inventory that relate to industrial cleaning solvent emissions, RTP used the 2026 projected value in 2026v2 modeling platform for 2026 from SCC 246020000 to represent the industrial portion of emissions in the ROP Inventory. (See file: 2026j proj VCPy solvents 2016fj 10jul2021.v0.csv.FIP32 in EPA's modeling platform).

Table 18. Industrial Solvent Cleaning Emissions in 2026 ROP Inventory

SCC	Description	2026 Summer Weekday (tpd)
2460500000	C&C: Coatings and Related Products (industrial component only based on 2016v2 estimate)	3.9784
2401200000	Other Special Purpose Coatings	0.7914
	TOTAL	4.7698

5.2.9 Other Potential Industrial Cleaning Solvent Operators

The Industrial Cleaning Solvents CTG regulates consumer and commercial products that are used to remove such compounds as dirt, adhesives, inks, coatings, and other unwanted materials. Industrial operations across all types of source categories may use these products, and RTP did not compile a separate list of stationary sources potentially subject to this CTG RACT.

5.2.10 Potential Industrial Cleaning Solvents CTG RACT VOC Emissions Reductions

EPA's presumptive RACT requirements include work practice requirements, a proposed emissions limitation, and an alternative emissions standard that apply to facilities exceeding a 15 lb/day VOC emissions threshold. Table 19 displays these requirements.

Table 19. Industrial Clean Solvent Presumptive CTG RACT Requirements

Operation	Presumptive RACT
Work Practices	Cover open contains, minimize air circulation and cleaning operations, properly dispose of used solvent, minimize emissions
VOC Content Limit	0.42 lb VOC/gal or achievement of 85% emissions control
Alternative	Vapor pressure equal to or less than 8 mm Hg

In the supporting documentation for the Industrial Solvent Cleaning CTG, EPA estimated that 71,000 tpy of VOC were emitted from nonattainment area CTG sources. It also estimated that implementing the lb/gal VOC content limit and work practice requirements would reduce emissions by 67,000 tpy of VOC, which computes to a 94% emissions reduction. To calculate potential emission reductions from implementing the CTG RACT in Clark County, RTP estimated emissions reductions using the national average and an 80% rule effectiveness (Table 20).

Table 20. Projected VOC Emissions Reduction from Industrial Cleaning Solvent CTG RACT

Controllable VOC Emissions (tpd)	Control Efficiency	Rule Effectiveness	Projected Emissions Reductions (tpd)
4.77	94%	80%	3.74

5.2.11 Graphic Arts

CTG: Control of Volatile Organic Emissions from Existing Stationary Sources – Volume VIII: Graphic Arts – Rotogravure and Flexography

EPA Document Number: EPA-450/2-78-033

CTG: Control Techniques Guidelines for Flexible Packaging Printing

EPA Document Number: EPA-453/R-06-003, 2006/09

CTG: Offset Lithographic Printing and Letterpress Printing

EPA Document Number: EPA-453/R-06-002, 2006/09

Conclusion:
DES will promulgate a Graphic Arts CTG RACT rule covering offset lithographic, letterpress and flexible package printing because at least one stationary source may be operating in HA 212. DES submits a negative declaration for the 1978 Rotogravure and Flexographic Source CTG source category because there are no identified stationary sources in the source category operating within HA 212.

Discussion:
Graphic arts operations in the printing and publishing industry use inks and other solvent-based materials. EPA issued three CTG documents that affect this source category. The first, issued in 1978, applies to graphic arts operations that use flexographic or rotogravure printing for publication and for packaging and emit at least 100 tpy. In 2006, EPA issued two additional CTGs that apply to flexible packaging and to offset lithographic and letterpress printing processes that emit at least 15 lb/day of VOC and have a PTE, from heatset inks and dryers (emitting inks, coatings or adhesives), greater than 25 tpy before consideration of emissions controls.

The following SCC codes are associated with this source category:

- 40500308–9 Point Source: Flexographic Dryer and other non-dryer printing – Graphic Arts
- 40500204–05 Point Source: Letterpress Dryer and other non-dryer printing – Graphic Arts
- 40500402–03 Point Source: Lithographic Printing Dryer and other non-dryer printing – Graphic Arts
- 40500515–16 Point Source: Rotogravure Dryer and other non-dryer printing – Graphic Arts
- 36000102 Point Source: Flexographic: Scrap Substrate Collection – Graphic Arts
- 36000104 Point Source: Lithographic: Scrap Substrate Collection – Graphic Arts
- 36000103 Point Source: Rotogravure: Scrap Substrate Collection – Graphic Arts
- 2425000000 Nonpoint Source: Solvent – Graphic Arts

The ROP Inventory also includes point source emitters under graphic art SCC codes or other, now-retired codes (Table 21). CPP Acquisition is the largest emitter in the inventory, but RTP could not locate CPP Acquisition through Yellow Pages and web-based searches; and therefore, assumes that the company is no longer in operation.

Table 21. Graphic Arts VOC Emissions in ROP Inventory (Point Sources)

Facility Name	Facility ID	Type	SCC	2017 Summer Weekday (tpd)	2026 Summer Weekday (tpd)	Category
CPP Acquisition	15193	Dryer	40500101	0.0018	0.0018	Other
CPP Acquisition	15193	Printer	40500401	0.0561	0.0561	Lithographic
Las Vegas Color Graphics	1149	Printing press	40500411	0.0200	0.0200	Lithographic
Las Vegas Review-Journal	588	Parts washer	40500417	0.0221	0.0265	Lithographic
Nevada Color Litho	754	Printing press	40500433	0.0517	0.0517	Lithographic
West Rock	1055	Printing press	40500501	0.0298	0.0298	Gravure
Berry Plastics Corp.	597	Offset printing	40500802	0.0154	0.0185	Fugitive Cleaning Rags
			TOTAL EMISSIONS	**0.1969**	**0.2026**	

Berry Plastics Corporation operates under the authority of a minor NSR permit. The emissions reported in the ROP Inventory are associated with cleaning rags, but Berry also operates offset printers with a VOC PTE of 19.62 tpy.

West Rock is the only point source reporting emissions for a rotogravure category but the emissions are well below the 100 tpy applicability threshold for the 1978 Rotogravure and Flexography CTG. Therefore, it is not part of the CTG source category.

The ROP Inventory also includes nonpoint source emissions for solvent use related to graphic arts operations under SCC 2460200000 (Table 22).

Table 22. Graphic Art Operations in ROP Inventory (Nonpoint Sources)

SCC	Description	2017 Summer Day Emissions (t/d)	2026 Summer Weekday Emissions (tpd)
2425000000	Solvent Utilization; Graphic Arts; All Solvents	2.2024	2.5514

5.2.12 Other Potential Graphic Art Operators

RTP located an additional 137 companies that engage in some type of printing activity (Table 23). In most cases, the types of printing operations for these facilities are unknown. Because these facilities are not permitted under the Part 70 Operating permit program, DES concludes that none of these facilities would be part of the 1978 CTG source category. It is also unknown whether any of these facilities have operations that exceed the 2006 CTGs' presumptive applicability thresholds.

Table 23. Businesses with Potential Graphic Art Operations

Name	Address	City	ZIP
Wall Sensations of Nevada LLC	5321 E Shaw Butte Dr		85254
7 Printing and Mailing LLC	2710 E Patrick Ln #1	Las Vegas	89120
A & B Printing & Mailing	2908 S Highland Dr #B	Las Vegas	89109
A2 Exhibits, Inc.	6215 McGill Ave #C300	Las Vegas	89122
AA Printing Service	4800 S Maryland Pkwy #C	Las Vegas	89119
AB Screen Printing	236 Shoshone Ln	Henderson	89015
Abbott's Custom Printing and Specialty	411 Mark Leany Dr	Henderson	89011
ABC Imaging of Washington	3395 W Oquendo Rd	Las Vegas	89118
Absolute Exhibits, Inc.	6620 Escondido St #E	Las Vegas	89119
Accent Print Company LLC	2475 Chandler Ave #18	Las Vegas	89120
Ace Banners	3480 E Patrick Ln Ste Suite C	Las Vegas	89120
Advance Print LV LLC	591 Kavanaugh Pl	Las Vegas	89123
Airwolf 3D	6580 Spencer St #120	Las Vegas	89119
AlphaGraphics Las Vegas	7135 Bermuda Rd	Las Vegas	89119
Altitude Color Technologies	6185 S Valley View Blvd #B	Las Vegas	89118
Anthem East, Inc.	10624 S Eastern Ave #A	Henderson	89052
ARC Document Solutions LLC	2925 E Patrick Ln #A & B	Las Vegas	89120
ARC Document Solutions, LLC	4345 Dean Martin Dr	Las Vegas	89103
Astound Group	5675 E Ann Rd	NLV	89115

Name	Address	City	ZIP
Big Mountain Imaging	4725 Copper Sage St	Las Vegas	89115
Candid Litho Printing, Ltd	4795 W Nevso Dr	Las Vegas	89103
Clark County Legal News	433 Concord Way	Henderson	89015
Color Gamut Digital Imaging LLC	1550 Executive Airport Dr #140	Henderson	89052
Color Reflections LLC	3560 S Valley View Blvd	Las Vegas	89103
Com Art Signs & Design LLC	3111 S Valley View Blvd #V-101	Las Vegas	89102
Creative Digital Printing	6415 Karms Park Ct	Las Vegas	89118
Curtis 1000 Inc./ Taylor Print Impressions	4151 N Pecos Rd #203	NLV	89115
Custom Jacks	26 Commerce Center Dr	Henderson	89014
DA Graphics LLC	3111 S Valley View Blvd #V-101	Las Vegas	89102
D'andrea Visual Communications LLC	70 W Craig Rd #100	NLV	89032
Delta 3D Printers LLC	6570 Spencer St #C-1	Las Vegas	89119
Derse, Inc.	3455 W Reno Ave #C	Las Vegas	89118
Derse, Inc.	3200 E Gowan Rd #115	NLV	89030
Desert Design and Print	693 N Valle Verde Dr #4	Henderson	89014
Design To Print, Inc.	7015 Corporate Plaza Dr #110	Las Vegas	89118
Digital Insight Printing, Inc	159 N Gibson Rd	Henderson	89074
Digital Print Solutions LLC	1929 Sunnyslope Ave	Las Vegas	89119
Display & Exhibit Builders and Warehousing, Inc.	5220 Steptoe St #2	Las Vegas	89122
EG3 Technologies LLC	980 American Pacific Dr #104	Henderson	89014
Exhibit Options	5470 E El Campo Grande Ave	NLV	89115
Express Imaging Corporation	3995 W Post Rd	Las Vegas	89118
FedEx Office & Print Services, Inc.	3708 S Las Vegas Blvd	Las Vegas	89109
FedEx Office And Print Services, Inc.	3950 S Las Vegas Blvd	Las Vegas	89119
FedEx Office and Print Services, Inc.	2288 S Nellis Blvd	Las Vegas	89142
FedEx Office and Print Services, Inc.	5775 S Eastern Ave #106	Las Vegas	89119
FedEx Office and Print Services, Inc.	395 Hughes Center Dr	Las Vegas	89169
FedEx Office and Print Services, Inc.	7620 S Las Vegas Blvd #100	Las Vegas	89123
FedEx Office and Print Services, Inc.	3150 Paradise Rd	Las Vegas	89109
Fedex Office and Print Services, Inc.	9516 W Flamingo Rd	Las Vegas	89147
Flint Group Packaging Inks North America Corporation	6405 E Centennial Pkwy	NLV	89115
Franklin Printing	6765 S Eastern Ave Ste #6	Las Vegas	89119

Name	Address	City	ZIP
Gable Signs & Graphics, Inc.	7440 Fort Smallwood Rd	Baltimore	21226
Gill's Printing & Color Graphics	6800 Paradise Rd	Las Vegas	89119
Gold Star Signs LLC	4386 E Alexander Rd Bldg 16	Las Vegas	89115
Graphicsmart LLC	1889 E Maule Ave #I	Las Vegas	89119
Green Valley Graphix & Window Tinting	600 W Sunset Rd #106	Henderson	89011
Greenspun Media Group LLC	2275 Corporate Cir #300	Henderson	89074
Haigs Quality Printing Nevada	6360 Sunset Corporate Dr	Las Vegas	89120
HikePrint LLC	4310 Cameron St #15	Las Vegas	89103
HTA Photomask	2580 E Sunset Rd	Las Vegas	89120
Impress By Print LLC	6555 S Tenaya Way #900	Las Vegas	89113
In Business Las Vegas LLC			
Ink Drops Printing & Design	4640 Arville St #G	Las Vegas	89103
Intershine Graphics Inc	5075 Cameron St #E	Las Vegas	89118
Custom Jacks	26 Commerce Center	Henderson	89014
J&J Marketing, Inc.	2545 Chandler Ave #10, 25, 26	Las Vegas	89120
Jackpot Printing AG, LLC	6765 S Eastern Ave #6	Las Vegas	89119
King Printing	3411 W Oquendo Rd	Las Vegas	89118
L&K Print	855 E Twain Ave #125	Las Vegas	89169
Larger Than Life, Inc.	4385 Cameron St #A	Las Vegas	89103
Las Vegas Banner Factory	4572 W Hacienda Ave	Las Vegas	89118
Las Vegas Custom Signs LLC	3575 W Cheyenne Ave #103	NLV	89032
Las Vegas Sign Pros	7745 Boswell Ct	Las Vegas	89139
Las Vegas Color Graphics	4265 W Sunset Rd.	Las Vegas	89118
Las Vegas Sun, Inc.	2275 Corporate Cir #280	Henderson	89074
Las Vegas Review-Journal	333 S Las Vegas Blvd	Las Vegas	89101
Las Vegas Weekly LLC			
Marita Alegre	1712 Flat Ridge Rd	Henderson	89014
Marx Digital Mfg, Inc.	1850 E Maule Ave	Las Vegas	89119
Master's Graphics LLC	3230 W Hacienda Ave #302	Las Vegas	89118
MB Exhibits LLC	5220 Steptoe St #2	Las Vegas	89122
Mega Structures, Inc.	4660 Berg St	NLV	89030
Moore Wallace North America	6305 Sunset Corporate Dr	Las Vegas	89120
National Signs (Kaufman) LLC	3830 Rockbottom St	NLV	89030
Nevada Business Magazine	1549 Foothills Village Dr	Henderson	89012
Nevada Color Litho	4151 N Pecos Rd #203	Las Vegas	89115
Never Late Printing	3920 E Patrick Ln #1	Las Vegas	89120
New Writers' Ink Publishing Company Inc.	4728 Cedar Ranch Ct	NLV	89031
NY Sign Experts LLC	1570 N Christy Ln	Las Vegas	89110
OkBanners	5050 Steptoe St #A1	Las Vegas	89122
Orbus LLC	4850 Statz St	NLV	89081

Name	Address	City	ZIP
Patrick's Signs, Inc.	5115 Arville St	Las Vegas	89118
Plasticard Locktech International LLP	1220 Trade Dr	NLV	89030
Predator Signs & Graphics LLC	954 Harbor Ave	Henderson	89002
Print Plus More	9550 S Eastern Ave #253	Henderson	89074
Printflix	1950 S Rainbow Blvd #104		89146
Proffiti	948 Empire Mesa Way	Henderson	89011
R&M Bindery LLC	6041 McLeod Dr	Las Vegas	89120
R.D. Talley Books Publishing LLC	2208 Chipplegate Way North	NLV	89032
Rapid Color, Inc.	6445 Karms Park Ct	Las Vegas	89118
Rawlins Graphics and Design	6255 McLeod Dr #1–4	Las Vegas	89120
Redsand Graphics and Printing LLC	3950 N Las Vegas Blvd #104	Las Vegas	89115
RGS Reprographic Solutions	6645 S Eastern Ave #101	Las Vegas	89119
RoxMedia Group LLC	2900 E Patrick Ln #7	Las Vegas	89120
Royal Printing Company Inc.	3390 S Valley View Blvd	Las Vegas	89102
Sarchi Solutions	1711 Highland Ave #A		89102
Scanlab Technologies	6625 S Valley View Blvd #232	Las Vegas	89118
Scooterbay Publishing, Inc.	2737 Craigmillar St	Henderson	
Showbiz Weekly, Inc.			
Sparks Marketing Corp.	4975 N Pecos Rd	NLV	89030
SpeedPro Imaging Gold Studio	6290 S Pecos Rd #300	Las Vegas	89120
Square Foot Printing LLC	4071 Silvestri Ln #B-3	Las Vegas	89120
Stella Brands Packing LLC	7060 W Warm Springs Rd #130	Las Vegas	89113
Sun Valley Imaging & Technologies	4685 Copper Sage St	Las Vegas	89115
Super Color Digital LLC	3451 W Martin Ave #A	Las Vegas	89118
Synq Solutions, Inc.	4855 Engineers Way #102	NLV	89081
Taylor Print & Visual Impressions, Inc.	4151 N Pecos Rd	Las Vegas	89115
The Plastic Man	3823 Renate Dr	Las Vegas	89103
Slip Seal Company LLC	4550 Donovan Way #112	NLV	89031
The UPS Store #1390	2657 Windmill Pkwy	Henderson	89074
Thegraphxshop LLC	608 Comodo St	Henderson	89011
Time Printing Inc	1224 Western Ave	Las Vegas	89102
Toryon Technologies, Inc	6672 Spencer St #400	Las Vegas	89119
Two Plus Two Publishing LLC	32 Commerce Center Dr	Henderson	89014
The UPS Store #6980	2300 Paseo Verde Pkwy	Henderson	89052
Valhalla Printing LLC	954 Harbor Ave	Henderson	89002
Valley Horse News LLC			
Vanwie, Lynda	9550 S Eastern Ave #253	Henderson	89074

Name	Address	City	ZIP
Vintage Expression 702 (The Robin Agency)	432 Ackerman Ln	Henderson	89014
Vision Sign, Inc.	6630 Arroyo Springs #600	Las Vegas	89113
Vista Exhibits, Inc.	3220 E Charleston Blvd		89101
Westrock CP	6405 E Centennial Pkwy	NLV	89115
Wilen Vegas	3325 W Sunset Rd	Las Vegas	89118
Yume Designs	1945 Buckeye Hill Ct	Henderson	89012

5.2.13 Potential Graphic Arts CTG RACT Emissions Reductions

EPA's CTG RACT documents identify a variety of options for controlling VOC emissions from inks, coatings, adhesives, and cleaning materials used in printing operations, including add-on controls (e.g., carbon absorbers, incinerators), waterborne materials, and work practices.

Table 24 provides EPA's recommended control efficiency for CTG RACT as applied to emissions in HA 212. RTP assumed 100% emissions reductions for CPP Acquisition assuming it no longer operates. For Berry Plastics, RTP assumed a 25% control efficiency for implementation of work practice standards. For the remaining point sources, RTP assumed a 92.5% control efficiency based on the average control for offset lithographic printing presented in the Graphic Arts CTG.

To adjust the nonpoint source emissions, RTP applied an average control efficiency for both CTGs. For flexible packaging, EPA's RACT recommendations include a range of emissions control efficiencies based on equipment age, with equipment installed after 1995 capable of achieving 80% emissions reductions. RTP used this figure and computed an average control efficiency across the two CTG of 66%. RTP then adjusted the total projected emissions reductions for an 80% rule effectiveness.

Table 24. Projected VOC Emission Reductions from Graphic Arts CTG RACT

Emissions Source Type	Name	Summer Weekday Emissions (tpd)	Control Efficiency (%)	2026 Projected Emissions Reduction (tpd)
Point	CPP Acquisition	0.002	100	0.00
	CPP Acquisition	0.056	100	0.06
	Las Vegas Color Graphics	0.02	92.5	0.02
	Las Vegas Review Journal	0.027	92.5	0.02
	Nevada Color Litho	0.0517	92.5	0.05
	Berry Plastics Corporation	0.030	25	0.03

Nonpoint	Solvent Utilization; Graphic Arts; All Solvents	2.551	66	2.36
			Total Emissions Reductions	**2.54**
			Adjustment for 80% rule effectiveness	**2.03**

Using this approach, RTP calculated the potential for 2.54 tpd of VOC emissions reductions from adopting a Graphic Arts CTG. RTP applied an 20% adjustment for rule effectiveness which results in 2.03 tpd potential VOC emission reductions from the CTG RACT.

5.3 CHEMICAL PROCESSES

5.3.1 Pharmaceutical

CTG: Control of Volatile Organic Emissions from Manufacture of Synthesized Pharmaceutical Products (Pharma CTG)

EPA Document Number: EPA-450/2-78-029

Conclusion:
DES submits a negative declaration for the Pharma CTG because there is no confirmed stationary source in HA 212.

Discussion:
EPA issued the Pharma CTG in 1978. This CTG recommends VOC emissions control levels for the manufacturing of pharmaceutical products by chemical synthesis, fermentation, extraction, formulation, and packaging, including production and separation of medicinal chemicals from microorganisms; manufacture of botanical and biological products by extraction of organic chemical from vegetative materials or animal tissue; and formulation of bulk pharmaceuticals into various dosage types, such as tablets, capsules, injectables, solutions, or ointments. In 1998, EPA also promulgated a NESHAP for this source category (40 CFR Part 63, Subpart GGG).

The Pharma CTG's presumptive RACT applies an emission unit- (rather than source-) based applicability threshold to some emission units of 15 lbs of VOC/day. While the Pharma CTG RACT includes recommended emissions controls based on emission unit type, EPA noted that a "…reasonable approach to regulation should investigate emissions levels and controls options for a given plant on a plant by plant basis" (Pharma CTG p. 2-4).

One SCC code is associated with this source category:

- 2301030000 Nonpoint Source: Pharmaceutical Industrial Processes

RTP was unable to locate point source-specific SCC codes. The ROP Inventory includes no emissions for this source category.

RTP identified several facilities through business licenses and Yellow Pages searches that could fall within the Pharma CTG source category. Although several new businesses manufacture cannabidiol (CBD) and other products through extraction of chemicals from the hemp plant, DES previously evaluated potential emissions from CBD extraction operations and found them insignificant.

RTP investigated the list of potential businesses in Table 25 and concluded that the list includes distributors, with no manufacturing capabilities, and the rest are unlikely to have emissions exceeding the VOC RACT applicability threshold.

Table 25. Businesses Potentially Operating Pharmaceutical Operations

Name	Address	Description	URL
Advanced Physique Nutrition LLC	2700 E Patrick Ln 6	Protein powders	Advanced Physique Nutrition
Agua Street LLC	340 Sunpac CT #4		
Alcala Pharmaceuticals	6125 W Sahara Ave		
Alt Zero, Inc.	6285 McLeod Dr #1		Alt Zero / The Lab
American Nutritional Corporation	2150 Sunrise Ave		American Nutritional
Angel Care Products	3352 Wayward Ct.		
Artesyn Biosolutions	1771 South Sutro		
Bespoke Pharmaceuticals LLC	5795 N Hollywood Blvd #901		
Bio Fine	2762 Boise St		
Bob Adler Sales	8217 Quail Arroyo Ave		
BPG Limited	9517 Grand Canal Dr.		
CannVital NV LLC	6021 Badura Ave #120	Bulk CBD isolate	CannVital NV
Cellmedics Inc.			
Central Admixture Pharmacy Services	7061 W. Arby Ave		
Concierge Compounding	1879 Whitney Mesa Dr.		
Copley Pharmaceuticals	2215 Renaissance Dr.		
Cynet Corporation			Cynet Systems
Donjo LLC	5608 Jelsma Ave		
Enzymebiosystems	8250 Charleston Blvd #120		
Evergreen Organix	3669 Hacienda Ave		Evergreen Organix
Fibroplate, Inc.	6280 S Valley View Blvd #104		
Free for All, Inc.	8396 Teton Crest Pl		
Frontier Pharmaceutical Distributors	5020 Schuster St		Invisicare
GB Sciences	3550 W Teco Ave		GB Sciences
Genesis Pharmaceutical	1710 Whitney Mesa Dr.		
Geneva Mfg LLC	3065 N Rancho Dr. #110		Geneva
GlaxoSmithKline	9232 Spruce Mountain Way		
Greenway Health Community LLC	6 Sunset Way #104		
Grove, Inc	1710 Whitney Mesa Dr.		
Herbalicious	2875 E Patrick Ln #A		Herbalicious
International Integrated Management	3800 Howard Hughes Pkwy		
Invicta Pharmaceutical			Invicta Pharmaceutical
IQ Medical Services	2224 Martinique Ave		
Janone, Inc	325 E Warm Springs Rd #102		
Kloehn Inc.	10000 Banburry Cross		
Las Vegas Trikes	10050 Banburry Cross Dr. #157		

Name	Address	Description	URL
Legend Pharmaceuticals	504 Lob Wedge Ct		
Ligand Pharmaceuticals	3753 Howard Hughes Parkway #355		
Linden, Inc.	7370 Eastgate Rd #110		
Liquid Chronic E Liquid	3230 Polaris Ave		Liquid Chronic
Longevinex	4425 S Jones Blvd		
McKesson Corp.	3008 Via Sarafina Dr.		
Medicreations	6370 Annie Oakley Dr.		
Medigard	101 Convention Center Dr.		
Medisca Inc.	3955 W Mesa Vista Ave		MEDISCA
Medisource	3975 W Quail Ave #10		
Mesa Oils	1051 Olsen St #1011		
MMI Laboratories, Inc.	4216 N Pecos Rd #106		
Molecular Throughput	5385 Cameron St #7		
Musclepharm Corporation	3753 Howard Hughes Pkwy #200-849		
My Life Bak	2767 Cherrydale Falls Dr		
Nano Solutions, LLC	601 E Charleston Blvd #100		
National Homeopathic Labs	4250 Wagon Trail Ave		Homeopathic Labs
Nectar Bath Treats	2020 Pama Ln		Nectar Bath Treats
Neometrx	3443 Neeham Rd		
Neutra Corp.	400 4th St #500		
Nevada Health RX	61 Spectrum Blvd		
Nevada Organic Remedies	3705 E Post Rd		
Novum Pharmaceutical Research	3700 Pecos-McLeod		Novum Research
Nuro Pharma	6380 Polaris Ave #B		
Nutri Pharmaceuticals Research, Inc.	3282 Rabbit Blush Ct		
Pacifix Group	10413 Shadowland Ave		
Pharmacyte Biotech	3960 Howard Hughes Pkwy #500		
PHP Institute	5961 McLeod Dr	CBD	PHP Institute | Better Business Bureau Profile
Praxsyn Corp	61 Spectrum Blvd		
Procaps Laboratories	430 Parkson Rd		
R&J Productions	1817 Hermitage Dr.		
Re Scents	7927 Aspendale Dr	Cologne / Perfume	REBL Scents
Real Aloe Solutions	7470 Dean Martin Dr. #102		
Reef Dispensary	3400 Western Ave		
Regulatory Compliance Inttvs	P.O. Box 959651		
Silver Sage Wellness LLC	4071 Ponderosa Way		
Skin Visible Pharmaceuticals	6320 S Sandhill Rd		
Spectrum Pharmaceuticals	11500 S Eastern Ave #240		
Sphaera Pharma, Inc	1810 E Sahara Ave #787		
Sprayable Energy LLC	3651 Lindell Rd. #D1113		
Syncor International Corp	61 Spectrum Blvd		Syngene CRO
Thinkbiome LLC	848 Rainbow Blvd #2967		
Unifern LLC	7720 Eastgate Rd		
Wild Leaf Holdings U.S. LLC	4751 Vanderberg Dr #A		Wildleaf

Name	Address	Description	URL
Worldwide Clinical Trials	11024 Calder Ave		
Yew Biopharm	723 S Casino Center Blvd		
Zurich Pharmaceuticals	2850 W Horizon Pkwy		

5.3.2 Polymers and Resins

CTG: Control of Volatile Organic Compound Emissions from Manufacture of High-Density Polyethylene, Polypropylene, and Polystyrene Resins (Polymer and Resins CTG)

EPA Document Number: EPA-450/3-83-008

CTG: Control of Volatile Organic Compound Leaks from Synthetic Organic Chemical and Polymer Manufacturing Equipment (Equipment Leak CTG)

EPA Document Number: EPA-450/3-83-006

Conclusion:
DES submits a negative declaration for the Polymer and Resins CTG because there is no identified stationary source in the source category operating within HA 212.

Discussion:
EPA issued the Polymer and Resins and the Equipment Leak CTGs in 1983 to regulate emissions from plastic products, synthetic resins, synthetic rubber, and organic fibers. The source category includes facilities operating under SIC codes 2821–2824. The Polymer and Resins CTG covers only continuous processes and only polymer manufacturing in the polyethylene, polypropylene, and polystyrene industry. EPA also promulgated NSPS for the polymer manufacturing industry in 1990 (40 CFR Part 60, Subpart DDD).

The following SCC codes are associated with this source category:

- 30108001 Point Source: Polymer and Resin – General
- 30108004 Point Source: Polymer and Resin – Material Recovery
- 30108003 Point Source: Polymer and Resin – Polymerization Reaction
- 30108005 Point Source: Polymer and Resin – Product Finishing
- 30108002 Point Source: Polymer and Resin – Raw Material Preparation
- 30880001 Point Source: Rubber and Misc – Plastic Products Equipment Leaks
- 30800700–99 Point Source: Rubber and Misc – Plastic Products
- 30800800–899 Point Source: Rubber and Misc – Plastic Products
- 30800699 Point Source: Rubber and Misc – Plastic Products – Other Not Classified
- 30800901 Point Source: Polystyrene

- 30102437 Point Source: Acrylic and Modacrylic Fibers
- 30801001–09 Point Source: Rubber and Misc – Plastic Products – Adhesives and Other
- 30108202 Point Source: Polymerization – Batch Cell
- 30108219 Point Source: Polymerization – Centrifuge
- 30102670 Point Source: Polystyrene – Stripper
- 2430000000 Nonpoint Source: Rubber and Plastics – Manufacturing Solvents
- 2308000000 Nonpoint Source: Rubber and Misc Plastic Products

Five stationary sources reporting point source emissions under SCC codes associated with the Polymer and Resin CTG source category are in the ROP Inventory; however, there are no nonpoint source emissions in the inventory. See Table 26.

Table 26. Polymer and Resin VOC Emissions in ROP Inventory

SCC	Facility	2017 Emissions Inventory (tpy)	2017 Summer Weekday Emissions (tpd)	2026 Summer Weekday Emissions (tpd)*
30800724	Artesian Spas	1.530	0.0042	0.0042
30800802	Metl Span	2.420	0.0066	0.0066
30800802	Universal Urethane	14.370	0.0394	0.0394
30801005	Metl Span	2.180	0.0060	0.0060
	TOTAL	**36.64**	**0.1005**	**0.1005**

*2023 emissions for point sources based on 1997 8-hour Ozone Second Maintenance Plan Emissions Inventory Estimates.

RTP reviewed the point sources in the inventory and determined that none of the point sources are part of the Polymer and Resin CTG source category. Artesian Spas's emissions are below EPA's general presumptive RACT level of 15 lbs of VOC/day. Universal Urethane's emissions, although reported under a rubber and miscellaneous plastic products category, are related to urethane foam production (SIC 3086), which is not part of the Polymer and Resin CTG source category. Metl Span, now known as Nucor Insulated Panel Group, Inc., operates a panel manufacturing and panel coating line under SIC code 3448 (Prefabricated Metal Building Components) which is not part of the Polymer and Resins CTG source category.

RTP located other companies through a search of the Yellow Pages and business licenses whose company descriptions suggest that the business could involve polymer and resin operations (Table 27).

A minor source permit for Primex Plastics identifies the facility as operating under SIC code 3081 (Plastic Films and Sheets), with a VOC PTE of 8.38 tpy. However, this SIC code is not part of the Polymer and Resins CTG source category. RTP reviewed the other businesses in Table 27 and determined they also were unlikely to emit above the CTG RACT applicability threshold.

Table 27. Businesses Potentially Engaged in Polymer and Resin Operations

Name	Address	ZIP	Description
Boxabl, Inc.	5345 E North Belt Rd #100	89115	Foam & house construction/ architectural coating
Deslauriers, Inc.	900 W Warm Springs Rd #109	89011	Miscellaneous - plastic injection molding products
Foster West	4336 Losee Rd #6–9	89030	Medical plastics
Kreysler & Assoc.			Plastic composite molded building material
Kymofoam	9765 Turtlehead Court / 3300 Sunrise Ave 101	89117	Polyurethane foam manufacturer; chemicals and allied products; resins and plastics
Parker Plastics Nevada LLC	4700 Engineers Way #101	89030	Plastics
Polymershapes LLC	6435 S Valley View Blvd #A	89118	Plastics manufacturing or distributor
Poly-West, Inc.	251 Conestoga Way	89002	Plastics manufacturing and recycling
Primex Plastics	752 Turtleback Rd	89024	Plastic extrusion facility
The Slip Seal Company LLC	4550 Donovan Way #112	89031	Rubber products and packaging
Welch Plastics	4080 W Desert Inn Rd #W-110	89102	Plastic
Westfall Technik, Inc.	3883 Howard Hughes Pkwy #590		Molded plastic parts

5.3.3 Rubber Tires Manufacturing

CTG: Control of Volatile Organic Emissions from Manufacture of Pneumatic Rubber Tires (Rubber Tire CTG)

EPA Document Number: EPA-450/2-78-030

Conclusion:
DES submits a negative declaration for this CTG category because there are no identified stationary sources in the source category operating within HA 212.

Discussion:
EPA established this CTG in 1978 to reduce emissions from the Rubber Tire source category. The CTG recommends emissions control for manufacturing processes such as under-tread cementing, tread-end cementing, bead dipping, and green tire spraying. EPA also promulgated an NSPS (40 CFR Part 60, Subpart BBB) and NESHAP (40 CFR Part 63, Subpart XXXX) for the source category.

The following SCC codes are associated with this source category:

- 30800101–199 Point Source: Rubber Tire Solvent – Mixing and Misc Operations
- 40700401–40799998 Point Source: Rubber Tire Solvent – Storage

RTP located no point or nonpoint source emissions in the ROP Inventory for facilities in the Rubber Tire Manufacturing source category. A national list of rubber tire manufacturers (available at U-Tires) shows no manufacturers located in Clark County. DES concludes there are no stationary sources operating in HA 212.

5.3.4 Synthetic Organic Chemical Manufacturing Industry

CTG: Control of Volatile Organic Compound Emissions from Reactor Processes and Distillation Operations in Synthetic Organic Chemical Manufacturing Industry (SOCMI CTG 2)

EPA Document Number: EPA-450/4-91-031

CTG: Control of Volatile Organic Compound Emissions from Air Oxidation Processes in Synthetic Organic Chemical Manufacturing Industry (SOCMI CTG)

EPA Document Number: EPA-450/3-84-015

CTG: Control of Volatile Organic Compound Leaks from Synthetic Organic Chemical and Resin Manufacturing Equipment

EPA Document Number: EPA-450/3-83-006

Conclusion:
DES submits a negative declaration for this CTG source category because there is no identified stationary source in the category operating within HA 212.

Discussion:
In 1985, EPA issued SOCMI CTG 1, which recommended emissions controls for air oxidation processes. The presumptive RACT level is based on use of a combustion device that reduces emissions to 98% by weight or 20 ppm. EPA followed CTG 1 by promulgating three NSPS in 1990–1993 (40 CFR Part 60, Subparts III, NNN, and RRR) that regulate emissions from air oxidation processes, reactor processes, and distillation operations.

Multiple SCC codes are associated with this source category, for example:

- 30117402 Point Source: Air Oxidation – Reactor
- 30181001 Point Source: Air Oxidation – Reactor – SOCMI
- 30119002 Point Source: SOCMI Reactor – Acetone
- 30116902 Point Source: SOCMI Reactor – Alkylation
- 30125802 Point Source: SOCMI Reactor – Benzene
- 30120553 Point Source: SOCMI Reactor – Dehydration
- 30121003 Point Source: SOCMI Reactor – Dehydrogenation
- 30109153 Point Source: Light End Distillation – Acetone
- 30130115 Point Source: Atmospheric Distillation – Vents

No point or nonpoint source emissions are in the ROP Inventory for the SOCMI CTG Source Category.

RTP identified the following companies that could fall within the SOCMI CTG source category through Yellow Pages listings of chemical manufacturers and business license information.

Table 28. Businesses Potentially Engaged in SOCMI Operations

Name	Address	Description
A-1 Chemical/Winzer	4755 Procyon St	
Armourcoat Surface Finishes, Inc	4330 Production Ct	Coatings
Bochasweet	7322 S Rainbow Blvd	
Brenntag Pacific	3880 E Craig Rd	
Brenntag West		
Cardinal Paint and Powder, Inc.	1900 Aerojet Way	
Chemstation	4440 Mitchell St	
Dioxide Pacific	2654 W Horizon Ridge #B-562	
Fabrichem Systems	1100 Foremaster Ln	
Maintenance Solutions Inc	9804 Bearpaw Ave	
Malicious Liquids, Inc	7665 Commercial Way #D	Miscellaneous - manufacturing e-liquid
May Chemical	PO Box 34525	
Nalco	333 N Rancho Dr	
Nevada Chemical Technologies	8013 Shorecrest Dr	
Nitrex, Inc.	201 E Mayflower Ave	
Nitrex, inc.	2925 Brookspark Dr	Chemical
Olin Corporation	245 Fourth St.	Alkalies and chlorine manufacturing - Chlorine mfg
Sahalee Liquor Company LLC	3866 Civic Center Dr	Alcohol; unknown whether retail, wholesale, or producer
Specchem LLC	3930 E Lone Mountain Rd	Chemical
St Dupont	3355 S Las Vegas Blvd	
The Slip Seal Company LLC	4550 Donovan Way #112	Rubber products and packaging
Timet	181 N Water St Gate 3	Titanium
UCI	3977 W Oquendo Rd #G	Paint and coating mfg - paints (except artist's) mfg
Univar USA	4650 S Valley Blvd	
Zenith Energy Enzymes, Inc	980 Mary Crest Rd #E	Miscellaneous - Blending and processing, packaging and distributions of enzymes products for agriculture, construction, oil field

Name	Address	Description
		services, pet shampoo, swimming pool cleaning, & industrial treatment

After further investigation, DES found that either the listed companies' operations were outside the scope of the CTG regulations (e.g., manufacturers inorganic chemicals) or emissions were unlikely to exceed the CTG applicability threshold. Thus, there are no stationary sources operating within HA 212.

5.4 PETROLEUM PROCESSES

5.4.1 Cutback Asphalt

CTG: Control of Volatile Organic Emissions from Use of Cutback Asphalt

EPA Document Number: EPA-450/2-77-037

Conclusion:
DES will adopt a regulation to satisfy CTG RACT requirements for this source category.

Discussion:
EPA issued the Cutback Asphalt CTG in 1977. Cutback asphalt, used for paving, is liquified with petroleum distillate. Emissions occur during application of the product while paving roads.

One SCC code is associated with this source category:

- 2461021000 Nonpoint Source: Nonindustrial – Cutback Asphalt

Table 29 shows 2026 summer weekday emissions for both HA 212 and all of Clark County.

Table 29. Cutback Asphalt VOC Emissions in ROP Inventory

SCC	Description	Clark County 2026 Summer Weekday VOC (tpd)	HA 212 2026 Summer Weekday VOC (tpd)
2461021000	Nonindustrial, Cutback Asphalt	0.83	0.78

5.4.2 Other Potential Cutback Asphalt Operators

Based on Yellow Pages searches and business license reviews, the following businesses may use cutback asphalt in their operations.

Table 30. Businesses Potential Engaged in Use of Cutback Asphalt

Name	Address	City	ZIP
American Eagle Ready Mix LLC	120 W Delhi Ave	NLV	89032

Name	Address	City	ZIP
American Eagle Ready Mix LLC	14355 Dixon St	Las Vegas	
Cemex Construction Materials Pacific LLC	10025 Moccasin Rd		89143
Cemex Construction Materials Pacific LLC	4001 Losee Rd	NLV	89030
Cemex Construction Materials Pacific LLC	5030 N Lamb Blvd	NLV	89030
Cemex	14998 S Las Vegas Blvd	Las Vegas	89124
Hybrid International LLC	235 W Brooks Ave	NLV	89030
Jensen Enterprises Inc.	3840 N Bruce St	NLV	89030
Las Vegas Paver Mfg. LLC	6645 Gomer Rd	Las Vegas	89139
Robertson's Ready Mix	5255 Beesley Dr	Las Vegas	89115
Robertson's Ready Mix	160 Fourth St	Henderson	89015
Robertson's Ready Mix	10811 W Washburn Rd	Las Vegas	89166
Robertson's Ready Mix	14575 Arville St	Las Vegas	89141
Sierra Ready Mix Limited Liability Company	4150 Smiley Rd	NLV	8915
Southwest Liquid Asphalt & Emulsions LLC	3752 N Bruce St	NLV	89030
Spartan Industries	4750 Copper Sage St	Las Vegas	89115
Sterling Nevada LLC	2825 Coleman St	NLV	89032
Western Pacific Precast LLC	5320 Sloan Rd	Sloan	89054
Ergon Asphalt and Emulsions Inc	3901 W Ponderosa Way	Las Vegas	89118
Nevada Ready Mix Bonanza	601 W Bonanza Rd.	Las Vegas	89106
Las Vegas Paving Corporation	W Lone Mountain Rd.	Las Vegas	89129
Las Vegas Paving Corporation	9325 S Jones Blvd	Las Vegas	89139

5.4.3 Potential Cutback Asphalt CTG RACT VOC Emission Reductions

The presumptive RACT emissions control is the substitution of emulsified asphalt for cutback asphalt. EPA estimated this RACT would lead to nearly 100% control of asphalt emissions. In 1978 and 1979, shortly after EPA issued the CTG RACT document, it issued three memoranda to clarify RACT requirements for the asphalt industry (Rhoads 1978, Rhoads 1979a, Rhoads 1979b). EPA explained that a total ban on cutback asphalt use was technically infeasible, and that use of cutback asphalt should be permissible for certain applications. It recommended VOC content limits ranging from 3–12% depending on the application; if states imposed a blanket VOC content limitation, then a range of 5–7% would be acceptable.

Section 60.4 of the AQRs prohibits use of cutback asphalt in the Las Vegas Valley (which includes HA 212) except in limited circumstances. EPA approved this regulation for inclusion in the Nevada SIP in 1984; however, the Board of County Commissioners repealed Section 60.4 in 2011 and DES can no longer enforce it. Thus, the rule produces no verifiable emissions reductions.

EPA's 2017 NEI emissions estimates, which the ROP Inventory reflects, were based on uncontrolled emissions and projected vehicle miles traveled (EPA 2021b). In the 2020 NEI, EPA applied an emissions factor of 815.97 lb of VOC/ton of asphalt in computing emissions, and RTP used this emissions factor to compute future emission reductions. This is roughly equivalent to 40% VOC content by weight. By requiring the VOC content of asphalt to be no greater than 0.5% by volume and assuming 80% rule effectiveness, DES would achieve a 0.62 tpd VOC emissions reduction within HA 212. By expanding the RACT rule to all of Clark County, DES would achieve a 0.66 tpd VOC emissions reduction (Table 31).

Table 31. Projected VOC Emissions Reductions from Cutback Asphalt CTG RACT for HA 212 and Clark County

Parameter or Calculation	2026 HA 212 Projected Summer Weekday (tpd) Value	2026 Countywide Summer Projected Weekday (tpd)	Unit
SCC 2461021000	0.78	0.83	tpd VOC
Emissions factor	815.97	815.97	lbs VOC/ton
Tons of asphalt per day = EF /2026tpd	1.92	2.04	tpd asphalt
Standard density of asphalt	145	145	lb asphalt/ft^3
Avg. density of solvent (med. cure)	7.82	7.82	lb VOC/gal
Conversion factor	7.48	7.48	gal per ft^3
lb asphalt/gal asphalt = (145 / 7.48)	19.39	19.39	lb/gal
0.5% by VOC volume by weight = (0.005 • (7.82/19.39))	0.00202	0.00202	lb VOC/lb asphalt
Emissions Reductions = 0.78 - (0.0020 • 1.92)	0.78	0.83	tpd VOC
Total Emission Reductions: 80% Rule Effectiveness = 0.78 - (0.78 • 2) + (0.0020 • 1.92 • 0.8)	0.62	0.66	tpd VOC

5.4.4 Gasoline Loading Terminals and Bulk Gasoline Plants

CTG: Control of Hydrocarbons from Tank Truck Gasoline Loading Terminals (Terminals CTG)

EPA Document Number: EPA-450/2-77-026

CTG: Control of Volatile Organic Emissions from Bulk Gasoline Plants (Bulk Plant CTG)

EPA Document Number: EPA-450/2-77-035

CTG: Control of Volatile Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems (Leaks CTG)

EPA Document Number: EPA-2-78-051

Conclusion:
Existing SIP-approved Sections 51 and 60.1 of the AQRs meet CTG RACT requirements Nevertheless, DES will adopt 40 CFR Part 60, Subparts XX and Xa, and 40 CFR Part 63, Subpart BBBBBB into the SIP to satisfy CTG RACT Requirements and improve rule effectiveness by promoting consistency and thoroughness in compliance obligations.

Discussion:
EPA issued two CTGs recommending emissions controls for gasoline loading plants and terminals: the Terminals CTG applies to larger facilities with daily throughputs of greater than 76,000 liters (l) (20,000) gal of gasoline/day, while the Bulk Plant CTG applies to smaller facilities with daily throughput below this value. Bulk gasoline plants serve as secondary distribution facilities that receive fuel from gasoline terminals and then transport it to local businesses via account truck. The Bulk Plant CTG applies to splash fill operations.

The Terminals CTG applies to loading gasoline into tank trucks at bulk terminals and requires submerged fill or bottom loading, or top filling with a vapor control system reducing emissions to 80 mg TOC/l or less of gasoline.

The Leaks CTG applies to gasoline trucks equipped for vapor collection, and bulk terminals, bulk plants and service stations equipped with a vapor balance and/or vapor processing system. It requires gasoline trucks to maintain pressure changes below certain levels and avoid visible leaks. It also sets standards to avoid leaks during loading and unloading.

The following SCC codes are associated with these source categories:

- 40600136 Point Source: Petroleum & Petroleum Product Transport – Splash Loading
- 40600101 Point Source: Petroleum & Petroleum Product Transport – Splash Loading
- 40600126 Point Source: Petroleum & Petroleum Product Transport – Submerged Loading
- 40600141 Point Source: Petroleum & Petroleum Product Transport – Balanced Submerged Loading
- 40400152 Vapor Collection Losses – Bulk Terminals
- 2501050000 Nonpoint Source: Bulk Gasoline Terminals – All Products
- 2501055120 Nonpoint Source: Bulk Terminals and Plants – Area Sources

There are two bulk gasoline plants/gasoline terminals listed in the ROP Inventory. None of the reported emissions from these facilities are from splash loading, so they would not be subject to the Bulk Plant CTG.

Table 32. Gasoline Terminal and Bulk Plant VOC Emissions in ROP Inventory

SCC	Business	SCC Description	2017 Summer Weekday (tpd)	2026 Summer Weekday (tpd)
40400150	Pro Terminal Operators	Loading Rack Evaporative Losses	0.0422	0.0438
40400178	Pro Terminal Operators	Tanks Internal Floating Roof	0.0334	0.0337
40400153	Harry Reid International Airport Tank Farm	Thermal Oxidizer Vapor Control Unit Losses	0	0
40400199	Harry Reid International Airport Tank Farm	Tank Other Not Classified	0.0392	0.0392
40400250	Harry Reid International Airport Tank Farm	Loading Racks	0.0013	0.0013
2501050120		Bulk Terminals and Plants – Area Sources	1.29	1.10622

5.4.5 Other Potential Gasoline Terminal or Bulk Plant Operators

RTP identified the following companies operating bulk gasoline terminals or plants through Yellow Pages or web searches.

Table 33. Businesses Potentially Engaged in Gasoline Terminal or Bulk Plant Operations

Company	Address	City	ZIP
River City Petroleum, Inc.	4915 North Sloan Lane	Las Vegas	89115
Eastern Sierra Oil	4825 North Sloan Lane	Las Vegas	
Haycock Petroleum Co.	715 West Bonanza Road	Las Vegas	
Rebel Oil Co.	2200 Highland Dr.	Las Vegas	
SC Fuels		NLV	
Olympic Petroleum		Las Vegas	
RelaDyne	2420 Losee Rd.	NLV	89030

5.4.6 Potential Gasoline Terminals and Bulk Plant CTG RACT Emissions Reductions

The Bulk Plant CTG provides three alternatives for imposing regulations:

- Option 1: Submerge fill or bottom fill of tank trucks;
- Option 2: Option 1 plus vapor balancing with storage tank; or
- Option 3: Option 2 plus vapor balancing for displaced truck vapors.

The Terminal CTG recommends an emissions limitation of 80 mg/l of gasoline loaded, assuming use of vapor control system achieving approximately 87% control efficiency. The Leaks CTG includes work practice requirements to ensure good maintenance and reduce equipment leaks.

Clark County has three SIP-approved AQRs that control emissions from gasoline loading Sections 51, and 52 and 60.1 (Table 34). AQR 52 is discussed further in Section 5.4.7 in reference to Gasoline Service Stations.

Table 34. Emissions Control Requirements for Bulk Gasoline Plants and Terminals in Air Quality Regulations

AQR No.	Name	Requirements	Version Approved	Current Version
51	"Petroleum Product Loading into Tank Trucks and Trailers"	Vapor collection and disposal or equivalent; bottom loading or submerged fill; properly functioning vapor collection with vapor tight seal	1978	2004 (no substantive changes)
52	"Handling of Gasoline at Service Stations, Airports and Storage Tanks"	Vapor-laden tank truck refilled only at facility with vapor control system; permanent submerge fill	1981	Repealed
60.1	"Evaporation and Leakage"	Requires use of best practices to reduce leaks	1979	Repealed

Table 34 shows that Section 51 and 60.1 together meet the third alternative presumptive RACT level of the Bulk Plant CTG, and meets the levels recommended in the Terminals CTG for gasoline tank loading by requiring vapor tight seals on a properly designed and operated vapor collection system. Section 60.1 also control leaks that could occur during these operations. While Section 51 does not impose the specific emissions limitation recommended in the Terminals CTG, DES requires a minimum 90% control efficiency (Section 51.4.3) which is roughly equivalent to the 87% control efficiency EPA assumed in the CTG cost analysis for the Terminals CTG. Section 51 is thus as stringent as both the Terminals and Bulk Plant CTGs RACTs. AQR Section 60.1 meets the Leak CTG by requiring use of work practices to reduce leaks. Collectively, these rules meet or exceed presumptive RACT recommendations for these CTG categories.

Nonetheless, the Board of County Commissioners repealed Section 60.1 and it is no longer enforceable; and although existing Section 51 requires compliance with the presumptive RACT emissions controls levels during storage and loading activities, DES is electing to replace both rules with existing federal NSPS and NESHAP regulations. This will streamline requirements and promote consistency and thoroughness in meeting compliance obligations.

Specifically, DES proposes to incorporate the NSPS in 40 CFR Part 60, Subparts XX, and Xa, and NESHAP in 40 CFR Part 63, Subpart BBBBBB into the SIP to satisfy CTG RACT requirements for these CTG source categories.

The following table displays the general control requirement of the NSPS and NESHAP that DES will adopt into the SIP to meet RACT, and explains how the rules meet the existing requirements of AQR 51 and are as least as stringent as EPA's presumptive RACT.

Table 35. NSPS and NESHAP Comparison to AQR and CTGs

Regulation	Affected Source	Construction or Reconstruction Date	Regulatory Citation	Requirement	General Exemption	AQR Sections 51 and 60.1 Comparison	CTGs Comparison
Part 60, Subpart XX Bulk Gasoline Terminals	All the loading racks at a bulk gasoline terminal (> 75,700 l/day gasoline or 20,000 gal/day throughput) which deliver liquid product into gasoline tank trucks	12/17/80-6/10/22	§ 60.502 Bulk Gasoline Terminal Loading Rack	Exceeds 90% control efficiency in 51.4, Equip with a vapor tight vapor collection system designed to collect the total organic compounds vapors displaced from tank trucks during product loading with emissions ≤ 35 mg TOC/liter gasoline loaded, or if equipped with existing system (constructed before Dec 17, 1980) ≤ 80 mg/l.		Exceeds 90% control efficiency in 51.4 for new sources, and is roughly equivalent to control efficiency requirement for existing sources.	Meets or exceeds 80 mg/L presumptive RACT.
Part 60, Subpart XXa Bulk Gasoline Terminals	Loading racks at a bulk gasoline terminal (> 75,700 l/day gasoline or 20,000 gal/day throughput) that deliver liquid product into gasoline cargo tanks including the gasoline loading racks, the vapor collection systems, and the vapor processing system	6/11/22 or after	§ 60.502a Bulk Gasoline Terminal Loading Rack	Use submerged fill and Equip with vapor tight vapor collection system to collect vapors from cargo tanks during loading.		Meets emissions control system requirement in 51.1, and exceeds control requirement for new sources.	Meets required control for existing sources and exceeds required controls for new sources.
				New Units: use Thermal Oxidizer reduce emissions to < 1.0 mg TOC/l; 3-hour rolling average temp, or vapor recovery system ≤ 550 ppm TOC on 3-hour rolling average			
Part 63, Subpart BBBBBB Bulk Terminals and Plants and Pipeline Facilities	Area source bulk gasoline terminal (≥ 20,000 gal/ day gasoline throughput), pipeline breakout station, pipeline pumping station, and bulk gasoline plant (< 20,000 gal) as specified	None	§ 63.11086 Bulk Gasoline Plant Loading Tanks and Trucks	If > 250 gallon, load tank or truck using submerged fill that meets specifications by date installed, and all tanks, minimize gasoline spills and follow other work practices such as monthly leak inspection.	Gasoline Service Stations	Meets 51.1.1 requirement to use submerged fill; although rule has no exemption, exempt facilities are covered by new AQR 102.	Meets presumptive RACT control option 1.
			§ 63.11088 and Table 2 Bulk Gasoline Terminal Loading Rack	If total gasoline throughput ≥ 250,000 gallons/day, equip with vapor collection system and reduce to 80 mg TOC/l		Meets 51.1 and 51.4.1 requirement for vapor collection and disposal.	Meets 80 mg/L presumptive RACT control requirement.

Regulation	Affected Source	Construction or Reconstruction Date	Regulatory Citation	Requirement	General Exemption	AQR Sections 51 and 60.1 Comparison	CTGs Comparison
			§ 63.11088 and Table 2 Bulk Gasoline Terminal Loading Rack	If total gasoline throughput < 250,000 gallons/day use submerge fill with pipe no more than 6 inches from bottom		Meets 51.1.1 requirement to use submerged fill.	Does not meet presumptive RACT emissions limitation of 80 mg/l, but this level of emissions control would be required for sources under Subpart XX.
			§ 63.11089 Bulk Gasoline Terminal and Plants	Monthly leak inspection		Meets 60.1 best practice requirement	Meets or exceeds presumptive RACT leak detection program.

EPA established or revised these federal emissions standards after determining presumptive RACT for the categories, and as such, they represent a progression in control and cost considerations.

Although there are some differences in applicability of the federal rules and the AQR, DES determined that these differences are not meaningful such that they decrease the stringency of the SIP by incorporating the federal rules by reference. For example, Subpart XX regulates facilities with a throughput greater than 20,000 gal/day, while AQR 51 includes an annual throughput limit that when divided evenly throughout the year would result in a lower daily throughput applicability criterion. DES used the annual throughput limit, however, to provide greater flexibility in operations, and a facility is more likely to exceed the 20,000 gal/day applicability of Subpart XX than the annual limit in AQR 51, making the applicability of Subpart XX more stringent than AQR 51.

While Subpart XXa does not include a specific throughput limit equivalent to the presumptive RACT 80 mg/L emissions limitation, facilities subject to Subpart XXa are also likely subject to Subpart BBBBBB which includes this specific limit and is being included in the rules DES will incorporate by reference in the SIP. Collectively, DES determined that EPA's federal rules represent the most current assessment of emissions control capabilities to meet the best available system of emission reduction under Section 111 of the Act, and the maximum achievable control technology ("MACT") under Section 112 of the Act. These regulatory standards exceed the statutory requirement for CTG RACT, and are equivalent or more stringent than AQR Section 51. DES therefore concludes that adopting these rules into the SIP will more than satisfy CTG RACT requirements.

DES estimates no additional emissions reductions will result from the CTG RACT requirements, but there will also be no loss in emissions reduction from removing AQR Section 51 from the SIP. The replacement of AQR 51 with the federal rules satisfies the Act's anti-backsliding provisions in Sections 110(l) and 193 because the federal rules are equivalent or more stringent than AQR Section 51, and adopting the federal rules will improve rule effectiveness by consolidating regulatory compliance obligations under the more detailed compliance demonstration requirements of the federal rules.

5.4.7 Gasoline Service Stations

CTG: Design Criteria for Stage I Vapor Control Systems – Gasoline Service Systems (Gasoline CTG)

EPA Document Number: EPA-450/R-75-10

Conclusion:
DES will adopt a regulation to satisfy CTG RACT requirements for this source category.

Discussion:
EPA issued the Gasoline CTG in 1975 to control the release of VOC from commercial gasoline stations. The CTG includes requirements to use Stage 1 vapor recovery when filling a storage tank and submerged fill from delivery vehicles to tanks, along with requirements to inspect and maintain the vapor recovery system. The CTG presumptive RACT applies to gasoline service stations exceeding 10,000 gal/month.

Some SCC codes associated with Gasoline Service Stations identify emissions after application of CTG RACT-level controls (i.e., Stage 1 vapor balance and submerge fill).

The following SCC codes are associated with "uncontrolled emissions":

- 2501060052 Nonpoint Source: Service Stations – Splash Filling
- 2501060050 Nonpoint Source: Gas Stations – Total

There are no emissions in the ROP Inventory associated with these SCC codes. Emissions from gas stations are associated with codes showing compliance with CTG RACT requirements.

5.4.8 Potential VOC Emissions Reductions from Gasoline Station CTG RACT

Numerous gas stations operate in HA 212. The relevant SIP-approved AQR is Section 52, "Handling of Gasoline at Service Stations, Airports and Storage Tanks." This regulation meets the requirements of the Gasoline Service CTG because it requires use of submerged filling and a vapor balance system for all gas stations constructed after Jan. 1, 1978. However, the Board of County Commissioners repealed Section 52 in 2011 and DES no longer enforces it.

In 2008, EPA promulgated a NESHAP regulating hazardous air pollutants (HAP) emissions from gasoline stations (40 CFR Part 63, Subpart CCCCCC). This NESHAP requires gasoline stations with a monthly throughput of 10,000 gallons or more to use submerge fill requirements consistent with Gasoline Service CTG RACT requirements (40 CFR Part 63.11117(b)). The NESHAP does not require facilities to use vapor balance systems unless gasoline throughput exceeds 100,000 gallons a month.

Because Section 52 is no longer in the AQRs and the NESHAP does not cover all gasoline stationary operations operating in HA 212, DES will promulgate a new CTG rule for this source category. DES estimates no additional emissions reductions will occur from sources already included in the ROP Inventory.

5.4.9 Oil and Natural Gas Industry

CTG: Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants

EPA Document Number: EPA-450/3-83-007

CTG: Control Techniques Guidelines for the Oil and Natural Gas Industry

EPA Document Number: EPA-453/B-16-001

Conclusion:
DES submits a negative declaration for the Oil and Natural Gas source categories because there are no confirmed stationary sources operating in HA 212.

Discussion:
EPA issued two CTGs affecting the natural gas industry. The first, issued in 1983, recommends controls to reduce emissions from equipment leaks at natural gas processing plants. The second, issued in 2016, more broadly recommends emissions controls for the oil and natural gas processing plants.

In the first CTG, the natural gas processing plant includes facilities separating natural gas liquids from field gas or fractionating components of the gas into ethane, propane, butane, and natural gas. The category does not include compressor stations, dehydration units, sweetening units, field treatment, underground storage, liquified natural gas, or field gas gather systems. The second CTG defines the source category to include all operations involved in extraction, processing, transmission, storage, and distribution of natural gas and crude oil to the point of custody transfer at a petroleum refinery.

RTP was unable to identify specific SCC codes that correspond to these operations. A search of business licenses identified no companies that may fall within this category. The U.S. Energy Information Administration identifies no natural gas processing plants in Nevada (EIA Independent Statistics and Analysis, accessed 11/29/2022). Therefore, no identified stationary sources in these CTG source categories operate within HA 212.

5.4.10 Petroleum Storage

CTG: Control of Volatile Organic Emissions from Storage of Petroleum Liquids in Fixed-Roof Tanks (Petroleum Storage CTG 1)

EPA Document Number: EPA-450/2-77-036

CTG: Control of Volatile Organic Emissions from Petroleum Liquid Storage in External Floating Roof Tanks (Petroleum Storage CTG 2)

EPA Document Number: EPA-450/2-78-047

Conclusion:
Existing SIP-approved Section 50 of the AQRs meets the presumptive RACT level for the Petroleum Storage CTG source categories. Nevertheless, DES will adopt 40 CFR Part 60, Subparts K, Ka and Kb, and 40 CFR Part 63, Subpart BBBBBB into the SIP to satisfy CTG RACT requirements and improve rule effectiveness by promoting consistency and thoroughness in compliance obligations.

Discussion:
In 1977, EPA issued a CTG specific to storage of petroleum in fixed roof tanks (Petroleum Storage CTG 1). The presumptive RACT applies to storage tanks with more than 150,000 L (40,000 gal) of storage capacity containing liquids with a true vapor pressure greater than 10.5 kPa (1.5 psi). The recommended control is installation of an internal floating roof on fixed roof tanks that store petroleum with a true vapor pressure greater than 10.5 kPa. The rule exempts tanks with capacities less than 422,675 gal capacity if storing crude oil and condensate before custody transfer.

EPA issued the Petroleum Storage CTG 2 the following year. It applies to storage vessels with greater than a 40,000 gal storage capacity with an external floating roof containing liquids with a true vapor pressure greater than 10.5 Kpa (1.5 psi). The CTG requires a retrofit with secondary seals or equivalent.

Calnev, a Part 70 Source subject to major source RACT, is the only stationary source that falls within this source category. RTP found no other emission sources in the ROP Inventory. However, the facilities identified in Section 5.4.4 and Table 32 could also operate fixed roof tanks that fall within this source category.

5.4.11 Potential VOC Emissions Reductions from Petroleum Storage CTG RACT

AQR Section 50 requires controls equivalent to EPA's presumptive RACT level (40,000-gal applicability; internal floating roof requirement). In 1977, 1980, and 1987, EPA issued NSPS that regulate the same universe of petroleum storage tanks as the Petroleum Storage CTG with equal or more stringent requirements (40 CFR Part 60, Subparts K, Ka, and Kb). EPA also promulgated storage tank requirements specifically for Bulk Gasoline Plants and Terminals in 40 CFR Part 63, Subpart BBBBBB. The following table displays the general control requirement of the NSPS and NESHAP that DES will adopt into the SIP to meet CTG RACT, and explains how the rules meet the existing requirements of AQR 50 and are as least as stringent as EPA's presumptive RACT.

Table 36. Comparison of NSPS and NESHAP to AQR and Presumptive RACT

Construction or Reconstruction Date	Regulatory Citation	Requirement	General Exemptions	Comparison with AQR 50	Comparison with CTGs
3/6/74-5/19/78	§ 60.112 Storage Vessel	If true vapor pressure of ≥ 78 mm Hg (1.5 psia) but ≤ 570 mm Hg (11.1 psia), equip with a floating roof, a vapor recovery system, or their equivalents.	Storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.	Meets AQR 50.1 applicability threshold and control and vapor pressure requirements, exemption not relevant to HA 212	Meets or exceeds internal or external floating roof and seal requirement and presumptive RACT includes similar exemption
6/11/73-5/19/78		If true vapor pressure of the petroleum liquid > 570 mm Hg (11.1 psia), equip with a vapor control system or equivalent.			
5/19/78-7/23/1984*	§ 60.112a Storage Vessels	If true vapor pressure of ≥ 10.3 kPa (1.5 psia) but ≤ 76.6 kPa (11.5 psia), equip with external floating roof meeting specs, fixed roof with internal floating roof meeting specs, or vapor recovery system	Each petroleum liquid storage vessel < 1,589,873 liters (420,000 gallons) used for petroleum or condensate stored, processed, or treated before custody transfer to unaffected facility.	Meets AQR 51.1 applicability threshold, vapor pressure, and control requirements.	Meets or exceeds internal or external floating roof and seal requirement and presumptive RACT includes similar exemption
		If true vapor pressure of the petroleum liquid > 76.6 kPa (11.1 psia), equip with a vapor recovery system meeting 95% reduction by weight			
7/24/84 and after	§ 60.112b Storage Vessel	Vessel either with a design capacity ≥ 151 m3 (39890 gal) containing a VOL with maximum true vapor pressure ≥ 5.2 kPa but < 76.6 kPa or with a design capacity ≥ 75 m3 but < 151 m3 containing a VOL with maximum true vapor pressure ≥ 27.6 kPa but < 76.6 kPa, equip with fixed roof and internal flooting roof, external floating roof, or closed vent system with control device with 95% efficiency	Capacity ≥ to 151 m3 storing a liquid with a maximum true vapor pressure < 3.5 kPa or with a capacity ≥ 75 m3 but < 151 m3 storing a liquid with a maximum true vapor pressure < 15.0 kPa.	More stringent than AQR 50's applicability and control requirements. Although AQR does not exempt bulk gasoline plants, these tanks will be regulated under Subpart BBBBBB.	Meets or exceeds presumptive RACT controls, but CTGs do not discuss an exemption for bulk gasoline plants
		design capacity ≥ 75 m3 which contains a VOL with maximum true vapor pressure ≥ 76.6 kPa, equip with closed vent system and 95% control or equivalent	Vessels located at bulk gasoline plants; vessels at gasoline service stations, vessels subject to Part 63, Subpart GGGG.	Equivalent to AQR 50's applicability and more stringent by specifying control efficiency of vapor control system. Although AQR does not exempt bulk gasoline plants, these tanks will be regulated under Subpart BBBBBB.	

Construction or Reconstruction Date	Regulatory Citation	Requirement	General Exemptions	Comparison with AQR 50	Comparison with CTGs
None	§ 63.11086 Bulk Gasoline Plant Loading Tanks and Trucks	If > 250 gallon, load tank or truck using submerged fill that meets specifications by date installed, and all tanks, minimize gasoline spills and follow other work practices such as monthly leak inspection.	Gasoline storage tanks used only for dispensing gasoline in a manner consistent with tanks located at a gasoline station are not subject to any of the requirements in this subpart. These tanks must comply with subpart CCCCCC of this part.	Meets AQR 51.1.1 requirement to use submerged fill requirement	Meets presumptive RACT control Option 1
	§ 63.11087 and Table 1 Bulk Gasoline Terminal Storage Tanks	If gasoline storage < 75 m3 or < 151 m3 and throughput $\leq$ 480 gal/day, equip with fixed roof, and set pressure relief valves to $\geq$ 18 inches of water	Aviation fuel loading at airports, marine tank loading,	Exceeds AQR 50.1 40,000 gal applicability threshold and imposes controls not required by AQR 50. AQR does not exempt airports, but airports will be regulated under AQR 102. Marine tank loading exemption not relevant to HA 212.	These tanks are not covered by presumptive RACT because they are below the applicability threshold.
	§ 63.11087 and Table 1 Bulk Gasoline Terminal Storage Tanks	If gasoline storage tank $\geq$ 75 m3, equip with close vent system with 95% control by weight, internal floating roof, or external floating roof; surge control tanks fixed roof with pressure vaccuum vent with pressure $\geq$ 0.5 inches of water	Bulk gasoline terminal not subject to control in Part 63, Subparts R or CC (Subpart R includes an equation for exemption, looks like CTG tanks all would be covered by Subpart CC)	Exceeds AQR 50.1 40,000 gal applicability threshold; and requires controls exceeding AQR 50 by specifying a control efficiency for the vapor collection system.	Exceeds presumptive RACT control level

Although there are some differences in applicability of the federal rules and the AQR and presumptive RACT, DES determined that collectively adopting all the federal rules fills the gaps left by any individual federal rule. For example, although Subpart Kb exempts bulk gasoline plants from its requirements, Subpart BBBBBB regulates these tanks with requirements that are more stringent than the AQR and presumptive RACT, and while Subpart BBBBBB exempts aviation fuel loading at airports, DES will regulate these activities under new AQR 102.

Collectively, DES determined that EPA's federal rules represent the most current assessment of emissions control capabilities to meet the best available system of emission reduction under Section 111 of the Act, and the maximum achievable control technology ("MACT") under Section 112 of the Act. These regulatory standards exceed the statutory requirement for CTG RACT, and DES therefore concludes that adopting these rules into the SIP will more than satisfy CTG RACT requirements,

DES estimates no additional emissions reductions will result from the CTG RACT requirements, but there will also be no loss in emissions reduction from removing AQR 50.1 from the SIP. The replacement of AQR 50 with the federal rules satisfies the Act's anti-backsliding provisions in Section 110(l) and 193 because the federal rules are equivalent or more stringent than the AQR and adopting the federal rules will improve rule effectiveness by consolidating regulatory compliance obligations under the more detailed compliance demonstration requirements of the federal rules.

5.4.12 Refinery Operations

CTG: Control of Refinery Vacuum Producing Systems, Wastewater Separators, and Process Unit Turnarounds (Refinery CTG)

EPA Document Number: EPA-450/2-77-025

CTG: Control of Volatile Organic Compound Leaks from Petroleum Refinery Equipment

EPA Document Number: EPA-450/2-78-036

Conclusion:
DES submits a negative declaration for these Refinery CTG source categories because there are no identified stationary sources in the source category operating within HA 212.

Discussion:
In 1977, EPA issued a CTG to recommend emissions controls for vacuum-producing systems, wastewater separators, and process unit turnarounds at petroleum refineries. It followed this CTG with an additional guideline document for control equipment leaks from petroleum refinery equipment.

RTP was unable to identify specific SCC codes that correspond to these operations. A search of business licenses identified no companies that may fall within this category. The U.S. Energy Information Administration also identifies no petroleum refineries operating in Nevada (U.S. Number and Capacity of Petroleum Refineries, accessed 11/29/2022).

6.0 SUMMARY OF FINDINGS

Table 37 summarizes the findings in Chapter 5.

Table 37. Summary of CTG RACT Analysis: Certification of No Sources Operating in HA 212 or Projected Emission Reduction (tpd) from CTG RACT Rules

Source Category	CTG	EPA Doc #	Emissions Reductions Estimate (tpd)	CTG Finding
SURFACE COATING OPERATIONS				
Aerospace Manufacturing and Rework	Control of VOC Emissions from Coating Operations at Aerospace Manufacturing and Rework Operations	EPA-453/R-97-004	N/A	No sources in the category; submitting negative declaration
Automobile and Light Duty Trucks	Control of Volatile Organic Emissions from Existing Stationary Sources - Volume II: Surface Coating of Cans, Coils, Paper, Fabrics, Automobiles, and Light-Duty Trucks	EPA-450/2-77-008	N/A	No sources in category; submitting negative declaration
	Control Techniques Guidelines for Automobile and Light-Duty Truck Assembly Coatings	EPA-453/R-08-006	N/A	
Autobody Refinishing	Reduction of Volatile Organic Compound Emissions from Automobile Body Refinishing	EPA-453/R-94-031	N/A	Does not define RACT; EPA promulgated federal rule that supersedes CTG RACT.

	Reduction of Volatile Organic Compound Emissions from Automobile Refinishing	EPA-450/3-88-009		
Coils	Control of Volatile Organic Emissions from Existing Stationary Sources - Volume II: Surface Coating of Cans, Coils, Paper, Fabrics, Automobiles, and Light-Duty Trucks	EPA-450/2-77-008	N/A	No sources in category; submitting negative declaration
Fabric	Control of Volatile Organic Emissions from Existing Stationary Sources - Volume II: Surface Coating of Cans, Coils, Paper, Fabrics, Automobiles, and Light-Duty Trucks (multicategory CTG)	EPA-450/2-77-008	N/A	No sources in category; submitting negative declaration
Flat Wood Paneling	Control of Volatile Organic Emissions from Existing Stationary Sources, Volume VII: Factory Surface Coating of Flat Wood Paneling (Flat Wood Paneling CTG)	EPA-450/2-77-008	N/A	No sources in category; submitting negative declaration
	Control Techniques Guidelines for Flat Wood Paneling Coatings	EPA-453/R-06-004		

Large Appliances	Control of Volatile Organic Emissions from Existing Stationary Sources – Volume V: Surface Coating of Large Appliances (Large Appliance CTG 1)	EPA-450/2-77-034	N/A	No sources in category; submitting negative declaration
	Control Techniques Guidelines for Large Appliance Coatings (Large Appliance CTG 2)	EPA 453/R-07-004		
Magnet Wire - Surface Coating	Control of Volatile Organic Emissions from Existing Stationary Sources – Volume IV: Surface Coating of Insulation of Magnet Wire	EPA-450/2-77-033	N/A	No sources in category; submitting negative declaration
Metal Cans	Control of Volatile Organic Emissions from Existing Stationary Sources - Volume II: Surface Coating of Cans, Coils, Paper, Fabrics, Automobiles, and Light-Duty Trucks (multicategory CTG)	EPA-450/2-77-008	N/A	No sources in category; submitting negative declaration
Metal Furniture	Control of Volatile Organic Emissions from Existing Stationary Sources – Volume III: Surface Coating of Metal Furniture (Metal Furniture CTG 1)	EPA-450/2-77-032	N/A	No sources in category; submitting negative declaration
	Control Techniques Guidelines for Metal Furniture Coatings (Metal Furniture CTG 2)	EPA 453/R-07-005		

Misc. Metal and Plastic Parts	Control of Volatile Organic Emissions from Existing Stationary Sources – Volume VI: Surface Coating of Miscellaneous Metal Parts and Products	EPA-450/2-78-015	0.13	Submitting CTG RACT Rule
	Control of Volatile Organic Emissions from Existing Stationary Sources – Volume VI: Surface Coating of Miscellaneous Metal Parts and Products	EPA 453/R-08-003		
Paper	Surface Coating of Paper	EPA-450/2-77-008	0	Certifying existing SIP-approved RACT rule
	Paper, Film, and Foil Coatings	EPA 453/R-07-003		
Boat and Shipbuilding	Control Techniques Guidelines for Shipbuilding and Ship Repair Operations	61 FR-44050 8/27/96	N/A	No sources in category; submitting negative declaration
	Control Techniques Guidelines for Fiberglass Boat Manufacturing Materials	EPA 453/R-08-004		
Undefined	Control of Volatile Organic Emissions from Existing Stationary Sources – Volume I: Control Methods for Surface Coating Operations	EPA-450/2-76-028	N/A	Does not define RACT
Wood Furniture	Control of Volatile Organic Compound Emissions from Wood Furniture Manufacturing Operations (Wood Furniture CTG)	EPA-453/R-96-007	N/A	No sources in category; submitting negative declaration
SOLVENT USERS				
Degreasing	Control of Volatile Organic Emissions from Solvent Metal Cleaning	EPA-450/2-77-022	0.33	Submitting CTG RACT Rule

Dry Cleaners	Control of Volatile Organic Emissions from Perchloroethylene Dry Cleaning Systems	EPA-450/2-78-050	N/A	CTG no longer applicable
	Control of Volatile Organic Emissions from Large Petroleum Dry Cleaners	EPA-450/3-82-009	N/A	No sources in category; submitting negative declaration
Industrial Adhesives	Control Techniques Guidelines for Miscellaneous Industrial Adhesives	EPA 453/R-08-005	0.90	Submitting CTG RACT Rule
Industrial Cleaning Solvents	Industrial Cleaning Solvents	EPA-453/R-06-001	3.74	Submitting CTG RACT Rule
Graphic Arts	Control of Volatile Organic Emissions from Existing Stationary Sources – Volume VIII: Graphic Arts-Rotogravure and Flexography	EPA-450/2-78-033	2.03	Submitting CTG RACT Rule
	Control Techniques Guidelines for Flexible Packaging Printing	EPA-453/R-06-003, 2006/09		
	Offset Lithographic Printing and Letterpress Printing	EPA-453/R-06-002, 2006/09		
CHEMICAL PROCESSES				
Pharmaceuticals	Control of Volatile Organic Emissions from Manufacture of Synthesized Pharmaceutical Products	EPA-450/2-78-029	N/A	No sources in category; submitting negative declaration
Polymer and Resins	Control of Volatile Organic Compound Emissions from Manufacture of High-Density Polyethylene, Polypropylene, and Polystyrene Resins	EPA-450/3-83-008	N/A	No sources in category; submitting negative declaration
	Control of Volatile Organic Compound Leaks from Synthetic Organic Chemical and Polymer Manufacturing Equipment	EPA-450/3-83-006		

Rubber Tires	Control of Volatile Organic Emissions from Manufacture of Pneumatic Rubber Tires (Rubber Tire CTG)	EPA-450/2-78-030	N/A	No sources in category; submitting negative declaration
SOCMI	Control of Volatile Organic Compound Emissions from Reactor Processes and Distillation Operations in Synthetic Organic Chemical Manufacturing Industry (SOCMI CTG 2)	EPA-450/4-91-031	N/A	No sources in category; submitting negative declaration
	Control of Volatile Organic Compound Emissions from Air Oxidation Processes in Synthetic Organic Chemical Manufacturing Industry (SOCMI CTG)	EPA-450/3-84-015		
	Control of Volatile Organic Compound Leaks from Synthetic Organic Chemical and Polymer Manufacturing Equipment	EPA-450/3-83-006		
PETROLEUM PROCESSES				
Cutback Asphalt	Control of Volatile Organic Emissions from Use of Cutback Asphalt	EPA-450/2-77-037	0.62 (or 0.66 countywide)	Submitting CTG RACT rule
Gasoline Terminals and Bulk Plants	Control of Hydrocarbons from Tank Truck Gasoline Loading Terminals	EPA-450/2-77-026	0	Submitting CTG RACT rule to replace Section 51 and 60.1.
	Control of Volatile Organic Emissions from Bulk Gasoline Plants	EPA-450/2-77-035		

	Control of Volatile Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems	EPA-450/2-78-051	0	
Gasoline Service	Design Criteria for Stage I Vapor Control Systems – Gasoline Service Stations	EPA-450/R-75-102	0	Submitting CTG RACT rule to replace Section 52
Oil and Natural Gas	Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants	EPA-450/3-83-007	N/A	No sources in the category; submitting negative declaration
	Control Techniques Guidelines for the Oil and Natural Gas Industry	EPA-453/B-16-001		
Petroleum Storage	Control of Volatile Organic Emissions from Petroleum Liquid Storage in External Floating Roof Tanks (Petroleum Storage CTG)	EPA-450/2-78-047	0	Submitting CTG RACT rule to replace Section 50
	Control of Volatile Organic Emissions from Storage of Petroleum Liquids in Fixed-Roof Tanks	EPA-450/2-77-036		
Refinery	Control of Refinery Vacuum Producing Systems, Wastewater Separators, and Process Unit Turnarounds (Refinery CTG)	EPA-450/2-77-025	N/A	No sources in category; submitting negative declaration

	Control of Volatile Organic Compound Leaks from Petroleum Refinery Equipment	EPA-450/2-77-025	N/A	
Total Potential CTG RACT VOC Emissions Reductions (tpd)			**7.75**	

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ATTACHMENT D:

Major Source
Reasonably Available Control Technology Analysis

Case-By-Case RACT for Major VOC and NO_x Sources in Hydrographic Area 212

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ACRONYMS AND ABBREVIATIONS

<u>Acronyms</u>

AFR	air-to-fuel injection ratio
AQR	Clark County Air Quality Regulation
ARA	Air Register Adjustment
BACT	Best Available Control Technology
BF	biased firing
BOOS	burner out of service
BT	burner tuning
CAM	compliance assurance monitoring
CCB	cyclonic combustion burner
CGS	Clark Generating Station
CCM	combined combustion modification
CCU	combined cycle units
CE	cost effectiveness
CEMS	continuous emission monitoring system
CEPCI	Chemical Engineering Plant Cost Index
CFB	ceramic fiber burners
CI	compression ignition
CO	carbon monoxide
CO_2	carbon dioxide
CT	combustion turbine
CTG	Control Techniques Guidelines (EPA)
DAQ	Division of Air Quality
DEFR	domed external floating roof
DES	Department of Environment and Sustainability
DLN	dry low NO_x
DLNC	dry low NO_x combustor
EAR	excess air reduction
EFRT	External Floating Roof Tank
EGR	exhaust gas recirculation
EPA	U.S. Environmental Protection Agency
EPMS	Engine Performance Management System
EU	emission unit
FBR	fluidized bed reactor
FGR	flue gas recirculation
FIR	forced internal recirculation
FIR2	fuel-induced recirculation
FRT	floating roof tank
GCP	good combustion practices
GFFM	gas flow fuel modifier
GHG	greenhouse gases
GMP	good maintenance practices
HA	hydrographic area
HAP	hazardous air pollutants

HC	hydrocarbons
HRSG	heat recovery steam generator
IFR	internal floating roof
ITR	injection timing retard
LAER	lowest achievable emission rate
LEA	low excess air
LNB	low NO_x burner
LVT	Las Vegas Terminal
MAT	manifold air temperature
MGMRI	MGM Resorts International
NAFB	Nellis Air Force Base
NAICS	North American Industrial Classification System
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGR	natural gas reburning
NMHC	nonmethane hydrocarbon
NO_2	nitrogen dioxide
NO_x	nitrogen oxide(s)
NRDC	Natural Resources Defense Council, Inc.
NSCR	non-selective catalytic reduction
NSPS	New Source Performance Standards
NSR	New Source Review
O_2	Oxygen
OC	oxidation catalyst
O&M	operations and maintenance
OFA	overfired air
OP	(Title V) Operating Permit
OT	Oxygen Trim
PTE	potential to emit
RACM	reasonably available control measure
RACT	reasonably available control technology
RAP	reduced air preheat
RBLC	RACT / BACT / LAER Clearinghouse (database)
RCB	radiant ceramic burner
REA	reduce excess air
RICE	reciprocating internal combustion engine
RVP	Reid vapor pressure
SCA	Staged Combustion Air
SCR	selective catalytic reduction
SIC	Standard Industrial Classification
SLN	$SoLoNO_x$
SNCR	selective non-catalytic reduction
SO_x	sulfur oxide(s)
SPC	Saguaro Power Company
SPGS	Sun Peak Generation Station
SVE	soil vapor extraction
TCI	total cost investment

TVP	true vapor pressure
ULNB	ultra-low NOx burner
VOC	volatile organic compound
VRU	vapor recovery unit
WFR	water-to-fuel ratio
WSI	water/steam injection

Abbreviations (units of measurement)

%	percent
% O_2	percent oxygen
bbl	barrels (of oil)
hp	horsepower
hr	hour
kPa	kilopascal
kW	kilowatt
lb	pound
MM Btu	million Btu (heat input)
MM Btu/hr	million Btu per hour
Pa	pascal
Ppm	parts per million
ppmvd	parts per million volume dry
psi(a)	pounds per square inch (absolute)
tpd	tons per day
tpy	tons per year

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1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

This document provides a series of case-by-case reasonably available control technology (RACT) analyses for individual major stationary sources of volatile organic compounds (VOCs) and nitrogen oxides (NO_x) within the Hydrographic Area (HA) 212 ozone nonattainment area in Clark County, NV. The analyses are based on (1) sources' self-determinations of RACT, and (2) supplemental information and additional analyses by the Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ), as needed. This report presents the resulting RACT determinations for existing major stationary sources (as defined in Title 40, Part 70 of the Code of Federal Regulations (40 CFR Part 70)).

Based on the limited number of major sources in HA 212's emissions inventory, DAQ has determined that the most appropriate course is to determine RACT on a case-by-case basis for each one. DAQ does not believe it is necessary to determine RACT for all future new or replacement emission units at this time because the Clark County Air Quality Regulations already require RACT, best available control technology (BACT), or lowest achievable emission rate (LAER) determinations for stationary sources that construct or modify above minor New Source Review (NSR) significant levels.

1.2 SUMMARY

DAQ conducted RACT analyses for emission units at eight major stationary sources in HA 212. Most units had relatively low levels of NO_x and/or VOC actual emissions, and many were close to or below the 5 tons per year (tpy) potential-to-emit (PTE) threshold that DAQ established for conducting a RACT analysis. This section summarizes the results for each source.

1.2.1 Nellis Air Force Base

The emission units at NAFB that were analyzed consisted of nine diesel generators, eight of them emergency generators, and a hush house with two aircraft engine test cells. Eighteen control technologies were considered in the analyses of the generators; only selective catalytic reduction (SCR) was considered for the hush house. For the generators, the permit already requires good combustion practices (GCP) and good maintenance practices (GMP); turbocharging; Injection Timing Retard (ITR) for A032, G032, and G033; and aftercoolers for all but the nonemergency A032. No other technologies were considered cost-effective. For the hush house, only SCR appears to have been addressed as a control technology. Information on SCR costs, feasibility, and even the level of control was unavailable, but given the nature of the unit (intermittent testing of aircraft engines), DAQ concluded that SCR is not cost-effective. Therefore, RACT for these NAFB units consists of the control technologies; emissions limits; monitoring, reporting, and recordkeeping; and startup, shutdown, and malfunction provisions already required in the NAFB Title V operating permit (OP).

1.2.2 Caesars

Caesars Entertainment, Inc. ("Caesars") owns a number of properties with boilers and emergency generators. DAQ identified and evaluated 23 boiler control technologies. For the five boilers reviewed for RACT, only one control technology (in addition to what is already required) appeared cost-effective: switching to ceramic fiber burners, which would have reduced emissions from 30 parts per million (ppm) at 3% O_2 down to 15 ppm and reportedly save fuel and reduce maintenance. However, Caesars' boilers are all around 30 MMBtu/hr in size and ceramic fiber burner applications, according to several manufacturers, are available only up to about 16 MMBtu/hr.[1]

Further research indicates that metal mesh burners, like ceramic burners, are ultra-low NO_x burners (ULNB) and can reduce emissions substantially—in this case, down to 9 to 15 ppm. The metal mesh burners are suitable for larger boilers up to over 100 MM Btu/hr, but the cost is much higher (an estimated $250,000, since metal mesh burners are custom-designed and built for each boiler make and model) and there are no fuel savings, so the metal mesh burner technology is not considered cost effective for these boilers.

Therefore, DAQ finds that ceramic fiber burners are not available for these emissions units and that metal mesh burners are not cost effective, so concludes that the existing controls constitute RACT for these boilers.

Caesars properties also host 27 emergency generators subject to RACT review. The diesel generators are rated from 600 to 2,100 kW, and are limited to 100 hours of operation per year for testing and maintenance and up to 50 hours per year for nonemergency situations (which count toward the 100 hours). All the engines are turbocharged and aftercooled. Of the 18 control technologies evaluated, only the existing controls (turbocharging, GCP/GMP, and aftercooler) were determined to be cost-effective. DAQ concludes that these existing controls constitute RACT for these emergency diesel generators. The Caesars Title V operating permit (OP) includes compliance and monitoring requirements to ensure these conditions are met; DAQ concludes these constitute adequate monitoring, reporting, and recordkeeping to ensure RACT compliance.

1.2.3 Switch

No individual Switch, Ltd ("Switch") emission unit has a PTE above 5 tpy NO_x, but the 117 large (3,353 horsepower (hp) / 2,503 kilowatt (kW)) emergency diesel generators nevertheless were reviewed in the RACT analysis. The Switch Title V OP requires that the source have turbochargers and aftercoolers on all emergency generators, follow the manufacturer's operations and

[1] The highest annual emissions from the five boilers from 2019 to 2021 is 10.89 tpy NO_x; ceramic burners, had they been applicable to these boilers, would have reduced that to 5.445 tpy, reducing NO_x by the same amount (5.445 tpy). The burners have the benefit of increasing efficiency and saving fuel, which makes them more cost effective. For example, the cost-effectiveness (CE) for CP02 with 2.74 tpy actual emissions (without considering fuel savings) is $3,895/ton, which is cost-effective, while the CE for CP04 with 1.08 tpy is $9,881/ton, which is not. However, a 5% fuel savings, assuming the lowest hours of operation (446.6—CP01 in 2021), would be $6,815/year, which would result in a CE of -$1,080 to -$2,739/year (depending on the unit), which is cost-effective. The reduction in actual emissions from equipping the boilers with ceramic burners (had ceramic burners been available for that size boiler) would have been 5.445 tpy NO_x.

maintenance (O&M) guidance, and ensure all 117 units comply with the emissions limitations in 40 CFR Part 60, Subpart IIII. DAQ concludes that these requirements are RACT. Switch's Title V OP includes compliance and monitoring requirements to ensure these conditions are met; DAQ concludes these constitute adequate monitoring, reporting, and recordkeeping to ensure RACT compliance.

1.2.4 MGM Resorts International

MGM Resorts International (MGMRI) is currently a major source of NO_x, with a source-wide PTE of 757.05 tpy, but it reported only 65.07 tpy of actual NO_x emissions in 2017. The emission units include two natural gas-fired boilers, each with a capacity of 32.66 million British thermal units per hour (MMBtu/hr), and 46 diesel-fired emergency generators ranging from 1,100 to 3,700 hp.

DAQ evaluated 23 boiler control technologies; only ceramic fiber burners appeared to be potentially feasible as additional RACT. However, the MGMRI boilers are all around 30 MMBtu/hr in size and ceramic fiber burner applications, according to several manufacturers, are available only up to about 16 MMBtu/hr.

Further research indicates that metal mesh burners, like ceramic burners, are ultra-low NO_x burners (ULNB) and can reduce emissions substantially—in this case, down to 9 to 15 ppm. The metal mesh burners are suitable for larger boilers up to over 100 MM Btu/hr, but the cost is much higher (an estimated $250,000, since metal mesh burners are custom-designed and built for each boiler make and model) and there are no fuel savings, so the metal mesh burner technology is not considered cost effective for these boilers.

Therefore, DAQ determined that ceramic fiber burners are not available for these emissions units and that metal mesh burners are not cost effective, so concludes that the existing controls constitute RACT for these boilers.

All 46 of the emergency generators are required to follow the manufacturer's O&M guidance, which is generally accepted as constituting GCP. In addition, the OP requires all units have turbochargers and aftercoolers except:

- Turbochargers only: EX007-EX010 and NY27-NY29.
- Neither: TM01.

TM01 is the only unit for which the OP does not explicitly require turbocharging or aftercoolers, but it is also the only unit specifically mentioned as subject to EPA's Tier Certification. The unit's manufactured control technology must comply with the applicable New Source Performance Standard, thereby meeting the requirements of this certification and satisfying the definition of RACT.

The emergency generators currently:

- Are all required to practice GCP and GMP;

- Have and use turbochargers and aftercoolers (except the eight units (EX007-010 & NY 27-29, and TM01) that are not required to have aftercoolers); and
- Have one unit Tier-Certified unit (TM01). It must meet the appropriate limit in 40 CFR Part 60, Subpart IIII.

DAQ has determined that the current control techniques (GCP/GMP, turbochargers, and aftercoolers except as noted above) constitute RACT for all the units reviewed. RACT for TM01, in addition to GCP/GMP, includes meeting the Tier Certification requirements, including emissions limits. MGMRI's Title V OP includes compliance and monitoring requirements to ensure all the above conditions are met; DAQ concludes these conditions constitute adequate monitoring, reporting, and recordkeeping to ensure RACT compliance.

1.2.5 Calnev Pipe Line

Calnev Pipe Line, LLC ("Calnev"), a Kinder Morgan subsidiary, owns and operates a petroleum products distribution terminal facility in HA 212. The Las Vegas Terminal's (LVT's) operations include receiving petroleum fuel products via pipeline or truck and transferring gasoline, diesel, and biodiesel from storage tanks into trucks via loading racks.

LVT had a VOC PTE of 187.4 tpy and actual VOC emissions of 59.31 tpy in 2017. Most of the individual units have a PTE below 5 tons per year, but DAQ asked that LVT address at least a majority of the emission units that contribute to its PTE.

LVT therefore grouped individual emission units so the group PTE exceeded 5 tpy, then conducted RACT analyses on these groups: (1) storage tanks (total PTE of 61.3 tpy VOC),[2] (2) a vapor recovery unit (14.5 tpy VOC),[3] (3) loading racks (65.7 tpy VOC),[4] (4) a remediation system (37.7 tpy VOC),[5] and (5) fugitive components, such as valves, flanges, fittings, and pump seals (6.6 tpy VOC). For each of these units or groups, DAQ conducted a RACT analysis and determined existing controls and compliance measures (specified in the Title V OP) constitute RACT. Therefore, no decrease in emissions will result from this determination.

1.2.6 Clark Generating Station

The emission units at CGS that were analyzed consisted of thirteen simple cycle combustion turbines (CTs) (Unit 4 and Units 11–22) and four combined cycle units (Units 5–8). All turbines were subject to RACT for NOx and Units 4 and 5–8 were subject to RACT for VOC.

For the NO_x RACT evaluation, DAQ considered the use of SCR, water injection, and GCP for Unit 4. For Units 5-8, DAQ considered the installation of SCR with the existing dry low NO_x combustors (DLNC) and for Units 11–12, DAQ considered the installation of DLNC with the current use of SCR and water injection. For the VOC RACT evaluation, DAQ considered the

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[2] Table 3-1, LVT RACT Analysis. No tank has a PTE of 5 tpy or more.

[3] The vapor recovery unit is itself a control device that LVT says is considered BACT.

[4] There are 15 loading racks. Most of the 65.7 tpy PTE is from gasoline dispensing. Assuming each rack has the same PTE, 65.7/15 = 4.38 tpy per rack, less than the 5 tpy PTE threshold for RACT review.

[5] This system is also considered BACT, per LVT.

use of oxidation catalyst controls and GCP for Units 4–8; Units 11–22 are already equipped with oxidation catalyst controls. All other control technologies were considered technically infeasible.

The evaluation showed that there were no cost-effective control options for NO_x or VOC for any of the units except Unit 4. For Unit 4, the proposed NO_x RACT for Unit 4 was an emission limit of 120 ppmvd @ 15% O_2 based on the use of GCP for all periods of operation; for all other units, DAQ determined the current NO_x limits represented RACT based on the use of existing control equipment and compliance determination procedures.

For VOC RACT, DAQ determined that RACT for Unit 4 was an emission limit of 21.6 lb/hr based on GCP. For Units 5-8, DAQ determined that the existing VOC limits represent RACT based on the existing control configuration and compliance determination procedures.

DAQ determined that GCP would also apply to startup and shutdown operations as part of the NO_x and VOC determinations for all applicable units. DAQ included a requirement to develop a best operating practices guideline with adequate reporting and recordkeeping procedures to ensure that each unit maintains compliance with the good operating practices work practice standard.

1.2.7 Sun Peak Generating Station

The emission units at SPGS that were analyzed consisted of three natural gas-fired, simple cycle CTs (Units 3–5). All units were subject only to a RACT evaluation for NOx. VOC RACT did not apply because emissions for each unit were below the RACT applicability threshold. There were no other sources at the facility with NO_x or VOC emissions above the applicability threshold.

All turbines are currently equipped with water injection for NO_x control. Potential upgrade options that were evaluated include SCR, DLNC, and the combination of SCR with DLNC for all units. All other options were considered technically infeasible. The cost evaluation was conducted based on actual emissions data due to limited operation of each unit. The evaluation showed that there were no cost-effective control options for any of the units. Therefore, DAQ determined the current NO_x limits represented RACT based on existing controls and compliance determination procedures.

DAQ also determined that GCP would apply to startup and shutdown operations, with an additional requirement to develop a best operating practices guideline with adequate reporting and recordkeeping procedures to ensure that each unit maintains compliance with the good operating practices work practice standard.

1.2.8 Saguaro Power Company

The emission units at Saguaro Power Company ("Saguaro") that were analyzed consisted of two natural gas/oil-fired combined cycle units (Units 1 and 2) and two natural gas-fired auxiliary boilers (Units 5 and 6). All turbines and boilers were subject only to a RACT evaluation for NO_x, since VOC emissions for these units were below the RACT applicability threshold. There were no other sources at the facility with NO_x or VOC emissions above the applicability threshold.

All turbines are currently equipped with steam injection and SCR for NO_x control. Potential control technologies that were evaluated included DLNC and SCR catalyst replacement. All other options were considered technically infeasible. The cost evaluation was conducted based on actual emissions data. The evaluation showed that there were no cost-effective control options for either unit. Thus, DAQ determined that the current NO_x limits represented RACT based on existing controls and compliance determination procedures.

Both boilers are equipped with LNB although the Unit 5 boiler is also equipped with flue gas recirculation (FGR). For Unit 5, DAQ evaluated an extensive list of potential NO_x control technologies although, with the exception of a few technologies, all were considered technically infeasible. DAQ lacked sufficient information to determine feasibility for certain combustion-related technologies, including LNB, staged combustion, excess air reduction, and gas flow modifiers. However, none of these options would be considered cost-effective regardless of whether they were deemed technically feasible. Therefore, DAQ concluded the current NO_x limit represented RACT using existing controls and compliance determination procedures.

For Unit 6, DAQ also evaluated an extensive list of potential control technologies although only the following technologies were considered technically feasible: LNB upgrade with FGR, the installation of a ceramic fiber burner, the installation of a forced internal recirculation burner, and fuel-induced recirculation, although further evaluation would be required to confirm the feasibility of the burner replacements and use of fuel-induced recirculation. Based on the cost evaluation, DAQ concluded there were no cost-effective upgrades for this unit. Therefore, the current NO_x limit represented RACT using existing controls and compliance determination methods.

Finally, DAQ proposed the use of GCP as RACT for all units during startup and shutdown operations, with an additional requirement to develop a best operating practices guideline.

1.3 REQUIREMENTS FOR RACT ANALYSIS BASED ON ACTUAL EMISSIONS

One of the more significant findings of this evaluation was that essentially all of the RACT analyses were conducted using either average annual actual emissions (usually a 3-year average, in tpy) or the highest annual actual emissions rate (in tpy) over some period of time (1 to 5 years), based on the DAQ RACT Methodology guidance document. The presumption behind this methodology is that the annual actual emissions used for the cost effectiveness calculation is representative of normal operation for the source as a whole and/or for the individual emissions unit being evaluated. Because actual emissions from many of the individual emissions units were low, the CE calculation is sensitive to the actual emissions levels.[6]

Although most sources indicated that the baseline period was reasonably representative of future operation, it is possible that unanticipated increases in operation may cause future emissions that,

[6] For example, a boiler with actual emissions of 2.74 tpy and a reduction of 1.15 tpy from a control technology has a CE of $7533/ton, above the $5500/ton threshold. If the actual emissions rose only 2.26 tpy, to 5 tpy, the reduction would be 2.1 tpy and the CE would drop to $4128/ton, below the threshold, so would be cost effective for RACT.

if used to re-evaluate RACT, would result in a CE below the RACT applicability threshold, particularly for those sources in the electric utility sector. Therefore, where actual emissions were used (instead of PTE) for the CE calculation, DAQ expects to require those sources to provide calendar year annual actual emissions information on at least the individual units analyzed. If such actual emissions from an emissions unit increases over the baseline actual emissions used in the RACT analysis by 5 tpy or more (particularly if such increase occurs 2 or more years within a 3-year period), DAQ will evaluate whether the increase represents an increase in normal operation. If so, DAQ may conduct a revised RACT analysis and, if the new analysis results in a CE below the threshold, impose that level of control as RACT.[7] The purpose of this tracking and reassessment is to ensure that unanticipated increases in actual emissions from these sources do not interfere with attainment and maintenance of the ozone NAAQS. Therefore, in addition to a reported actual emissions increase above the 5 tpy threshold, DAQ will weigh such factors as the likelihood that the increased actual emissions are more representative of normal operation in the future (e.g., a single year in which emissions increase above the 5 tpy threshold does not necessarily indicate that this new, higher level is representative or will be repeated in the future), whether such increase could interfere with progress toward attainment, and any changes to other factors that affect CE, such as increased costs for equipment, maintenance and operation of the control device or a reduced remaining life of the unit.

[7] DAQ would specify that the source is to make the comparison with baseline and to notify DAQ by within 30 or 60 days of the end of each calendar year whether actual emissions have increased by the triggering amount.

2.0 MAJOR VOC AND NO_X SOURCES IN HA 212

Through a review of the 2017 National Emissions Inventory and major source (Part 70) OPs, DAQ identified the following major sources that could be subject to VOC or NO_x RACT requirements.

Table 2-1. Major Sources in HA 212 Nonattainment Areas

NO_X Major Sources				
Facility ID	**Facility Name**	**Total Facility NO_X PTE (tpy)**	**2017 NEI Emissions (tpy)**	**2017 NEI Emissions (tpd)**
114	Nellis AFB	199.0[8]	19.81	0.05
257	Caesars Consolidated Properties	370.1	19.9	0.05
16304	Switch, Ltd.	246.18	33.23	0.09
825	MGMRI Resorts International	757.05	65.07	0.18
7	Clark Generating Station	2465.9	115.40	0.32
423	Sun Peak Generating Station	249.4	15.89	0.04
393	Saguaro Power Company	164.1	102.79	0.28
VOC Major Sources				
Facility ID	**Facility Name**	**Total Facility VOC PTE (tpy)**	**2017 NEI Emissions tpy**	**2017 NEI Emissions (tpd)**
13	Calnev Pipe Line LLC	187.4	59.31	0.16
7	Clark Generating Station	216.5	14.12	0.04

DAQ asked each major source to prepare and submit RACT analyses for its emission units. All the major sources agreed to provide this information.

[8] NAFB's most recent Authority to Construct (ATC) permit, issued 10/13/22, states that NO_x PTE is now 200.47 tpy.

3.0 MACT SOURCE RACT METHODOLOGY

Appendix 1, "Final RACT Methodology for HA 212 2015 8-Hour Ozone NAAQS," provides a complete description of the methodology used for making RACT determinations. To summarize: DAQ provided each major source the opportunity to submit a control technology analysis with a proposed RACT demonstration for its emission units, then invited these sources to submit the following information relative to a case-by-case RACT requirement:

1. Information sources relied on to identify available control options.
2. Ranking of available control options based on control effectiveness.
3. Evaluation of technical feasibility.
4. Annual and incremental cost effectiveness ($/ton).
5. Baseline and controlled tpy emissions estimates (and basis).
6. Environmental, energy, and other impacts (benefits and disbenefits); greenhouse gases (GHG), hazardous air pollutants (HAP), or other pollutants.
7. Proposed RACT emissions limitation or averaging approach.
8. Schedule for installing and operating any new or additional emissions control resulting from the RACT determination.
9. Proposed testing, monitoring, recordkeeping, and reporting methods that meet periodic or Compliance Assurance Monitoring (CAM) requirements.

To assure uniformity among major sources in the cost estimates, DAQ asked them to submit cost information using a 6% interest rate and the remaining useful life of the emission unit (assuming an original useful life of 30 years unless the source submits information justifying a different useful life). Sources could also provide information on actual interest rates available to them, which DAQ stated would be considered in determining their RACT.

DAQ advised major sources that the baseline emissions for CE calculations should be based on an emission unit's PTE, including consideration of existing, enforceable control technologies. Alternatively, if either the major source's or a particular emission unit's actual emissions over a representative period of operation were less than 70% of PTE, then the major source could elect to provide cost-effectiveness information based on actual emissions. This meant that actual emissions might be used as a baseline for all emission units if the major source's actual emissions were 70% below its PTE, or for an individual emissions unit if a unit's actual emissions were 70% below its PTE.

DAQ advised major sources to submit RACT analysis information on each emission unit having a PTE equal to or greater than 5 tpy, although in a few cases sources were asked to evaluate RACT for a group of similar emission units, such as storage tanks for VOCs. All of the major sources submitted self-determinations and generally followed DAQ guidance, providing information on their emission units, available control technologies, and cost-effectiveness. Information from the sources' self-analyses are included in this document's RACT analyses.

After receiving self-analyses from the major sources, DAQ reviewed the information for thoroughness and reliability and to determine if the source:

1. Included all applicable emission units;
2. Searched the RACT/BACT/LAER Clearinghouse (RBLC) and literature for potential control technologies;
3. Listed all available control technologies;
4. Followed the guidelines for determining RACT; and
5. Documented critical determinations (e.g., how the remaining useful life of equipment was determined).

The self-determined RACT analyses proved useful in DAQ's final RACT determinations.
In determining the suitability of a given control option for RACT, DAQ was guided by the cost-effectiveness values DAQ has approved in past control technology determinations, the cost-effectiveness guidance provided by EPA, and the cost thresholds found acceptable by other states. A cost-effectiveness threshold of $5,500/ton was used for this review, which was among the highest in a survey of state agencies.[9]

For its cost-effectiveness analyses, DAQ used a 30-year equipment life term and 6% interest and made conservative estimates, i.e., the values selected would result in a lower CE (in $/ton removed) than a less conservative estimate for items like maintenance costs. The remaining life is estimated for either: (1) the control device, if it can continue to serve when the emission unit it serves is replaced by a new emission unit; or (2) the emission unit if the control technique will be inherent to the unit. An example of the first is an SCR system that treats the exhaust gas from a diesel generator; if the generator is replaced, the SCR system could be connected to the new generator and continue operating. An example of the second is modifying a generator for ITR; that technology would be part of the existing unit, so the remaining life of the generator would be used. DAQ's guidelines are to use 30 years' remaining life unless a shorter remaining life is adequately documented; some of the source RACT analyses used less than 30 years but did not provide adequate documentation, so DAQ revised those analyses using 30 years. However, a useful life of less than 30 years may be more appropriate; if adequate documentation of a shorter life is provided, DAQ reviewed that information and decided whether to revise its analysis to reflect the shorter life.

Developing a CE value is an iterative process. The CE analyses are generally first-order approximations based on information available in the literature; in a few cases, vendor information on

[9] See, e.g., "2020 Reasonably Available Control Technology Demonstrations for the National Ambient Air Quality Standards for Ozone in San Diego County," Air Pollution Control District County of San Diego (October 2020), which used a $5,000/ton cost-effectiveness threshold.

cost or applicability is available. Costs are not corrected for inflation unless the first CE calculation for that emission unit was below the threshold, meaning it would be considered cost-effective. In such cases, cost is adjusted for inflation and the CE is recalculated. If the inflation-adjusted CE is still below the threshold CE of $5,500/ton, DAQ further reviews the parameters to determine whether a less conservative value is warranted; if so, one or more revised parameters are developed and CE is again recalculated. A CE value that is still below the CE threshold indicates the control technology for that emission unit is reasonable for RACT. Note, however, that most of the CEs developed in these analyses rely on literature values for at least some of the parameters used in the calculations. Sources affected by a RACT determination may elect to develop parameters based on vendor quotes for application of that control technology on their specific emission units and request that DAQ use those parameters instead. Since vendor quotes for specific units are more accurate and up to date than literature values, those parameters are usually preferred, so DAQ would usually accept them to recalculate CE.

Once DAQ determines the appropriate control measures that qualify as RACT, it next determines the RACT emissions limitation. If DAQ determines that the existing level of control is RACT, it will review the source's permit to ensure it contains an effective emissions limit (or equivalent) and adequate monitoring, reporting, and recordkeeping conditions to ensure compliance; if it does not, DAQ will revise the permit conditions as needed. If DAQ determines that no control measure is cost-effective because of reduced equipment life expectancy, it will consider requiring the emissions unit to shut down by a certain date and whether any interim measures are available to reduce emissions before the mandated shutdown date.

The RACT emissions limitation derived from this process represents the lowest achievable emissions level with which the emission unit(s) can continuously comply using the proposed RACT control option. The proposed limitation also includes requirements for startup, shutdown, and malfunction periods, with proposed definitions to govern the operations. The provisions may be included in a single RACT emission limitation recommendation, or as a separate emissions limitation recommendation when including these emissions in a generally applicable emission limitation would cause the proposed limitation to be too lax during times of normal operations. DAQ also considered using work practice requirements when numerical emissions limitations were not feasible.

4.0 ENGINE AND SMALL BOILER RACT

4.1 INTRODUCTION

This section explains DAQ's NO_x (and in some cases VOC) case-by-case RACT determinations for each of the major sources in HA 212 that is major mainly due to diesel engines (mostly emergency generators) and /or commercial boilers[10]. DAQ relied on information provided in the major sources' proposed RACT analyses (Appendices 2–9), supplementing these analyses where appropriate: for example, when one major source's RACT analysis identified additional potential control technologies for a similar type of equipment, DAQ used cost and emissions reduction information from that major source for multiple RACT determinations. In some cases, DAQ adjusted life expectancy in cost calculations when a source did not provide any basis for a shorter life expectancy.

This section does not repeat all the information relied on in each major source's proposed RACT analysis, but highlights key information critical to DAQ's decision-making process. Appendices 2–9 provide the full scope of information DAQ considered in making a RACT determination for each major source.

4.2 POTENTIALLY AVAILABLE NO_X CONTROL TECHNOLOGIES

Emissions units at several of the major sources are emergency generators, engines that serve as secondary sources of power whenever a primary source of power is interrupted or insufficient to meet short-term energy demands. These engines are generally powered with natural gas or diesel fuel, and run for fewer than 500 hours per year. When evaluating whether to regulate emergency generators, EPA generally has found that add-on emissions controls are not economically reasonable because of the few hours the engines operate in a year (Appendix 4, p. 2-2), and instead imposes operational restrictions and/or work practices to minimize emissions. Sections 4.2.1–4.2.16 provide an overview of the control technology options DAQ considered in determining RACT for emergency engines at major sources. Some descriptions are taken verbatim from a source's proposed RACT, with information added to explain the applicability of the control technology to emergency generators. A number of add-on control technologies are also applicable to boilers, as discussed below.

4.2.1 Selective Catalytic Reduction

SCR is a post-combustion treatment of the engine exhaust that involves the injection of ammonia into the system in the presence of a catalyst that converts NO_x emissions to nitrogen and water in the presence of a catalyst. SCR on boilers works in essentially the same manner: "The catalyst allows the ammonia to reduce NO_x levels at lower exhaust temperatures than an alternative control technology called selective noncatalytic reduction (SNCR). Unlike SNCR, where the exhaust gases must be approximately 1400–1600°F, SCR can be utilized where exhaust gases are between 500°F and 1200°F, depending on the catalyst used. SCR can result in NO_x reductions up to 75%" (Appendix 3, p. 2).

[10] See Sections 5 and 6 for the remaining major source RACT determinations.

New engines that must meet EPA's Tier 4 manufacturer certification standards are built with SCR systems. Existing engines can be retrofitted with SCR, but exhaust temperature will impact its effectiveness as an emission control device; at too low a temperature, SCR efficiency decreases. Figure 1 presents an efficiency curve for SCR operation at various temperatures. Extrapolating beyond the curve for a boiler or emergency generator with a 400°F flue gas temperature yields a NO_x removal efficiency of less than 5%.

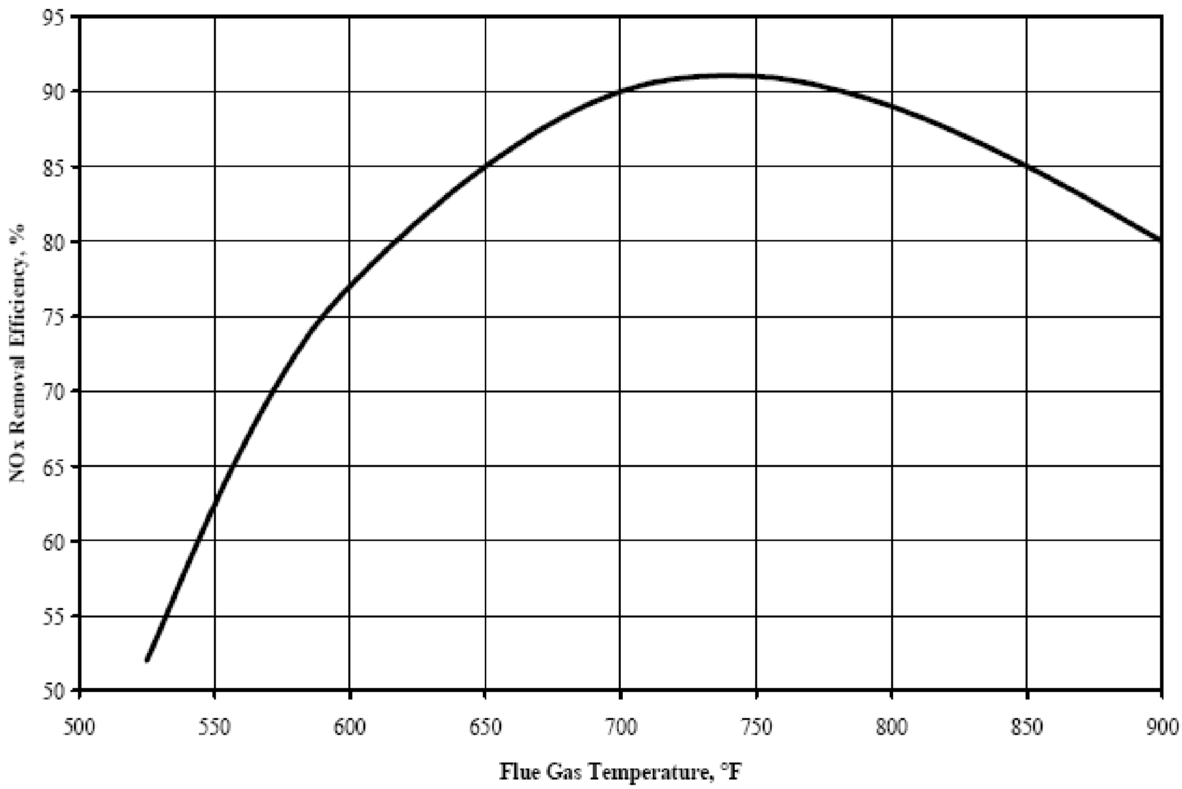

Figure 4-1. SCR–NO_X Removal versus Temperature.[11]

For emergency engines in particular, intermittent operation causes the average exhaust gas temperature to fall below the temperature required for the catalytic reaction (Appendix 2, p. 12). This makes application of SCR to most emergency engines economically unreasonable because the costs far exceed the emissions reduction benefit. Boilers are usually operated more than emergency generators, but SCR on small boilers, especially if the boilers are used intermittently (e.g., for hot water), are also generally not cost effective. For example, a search of the RACT/BACT/LAER Clearinghouse[12] for NO_x control determinations for small boilers shows a 2021 determination for the Lansing, MI Board of Water and Light (MI-0447) for a 50 MMBtu/hour natural gas-fired boiler of 30 ppm NO_x at 3% O_2 using LNB and FGR as BACT, which is generally more stringent than RACT. The cost-effectiveness of SCR for the boiler was calculated at $18,527, which was determined to be unreasonable for that facility.

[11] *Graph from* Air Pollution Control Cost Manual 7th Edition, Section 4, Section 4.2, Chapter 2 Selective Catalytic Reduction, p. 2-17. Document EPA-HQ-OAR-2015-0341-0061, available at: https://www.regulations.gov/document/EPA-HQ-OAR-2015-0341-0061.

[12] Database of control technology determinations maintained by EPA.

4.2.2 Selective Non-Catalytic Reduction

"SNCR involves the injection of a NO_x reducing agent, such as ammonia or urea, in the boiler exhaust gases at a temperature of approximately 1400–1600°F. The ammonia or urea breaks down the NO_x in the exhaust gases into water and atmospheric nitrogen. SNCR reduces NO_x up to 50%" (Appendix 3, Appendix B at p. 3).

SNCR is less costly than SCR, so the control technology can be more cost-effective, but like SCR, the efficiency of SNCR as a NO_x emission control decreases at higher and lower exhaust gas temperatures. The optimal range of SNCR is between 920–1,095°C (1,688–1,940°F). At a 400–700°F exhaust temperature, SNCR has a control efficiency of near 0%.

Figure 2 presents an efficiency curve for SNCR operations at various temperatures. The Y axis is % NO_x control; the X axis is temperature in °C.

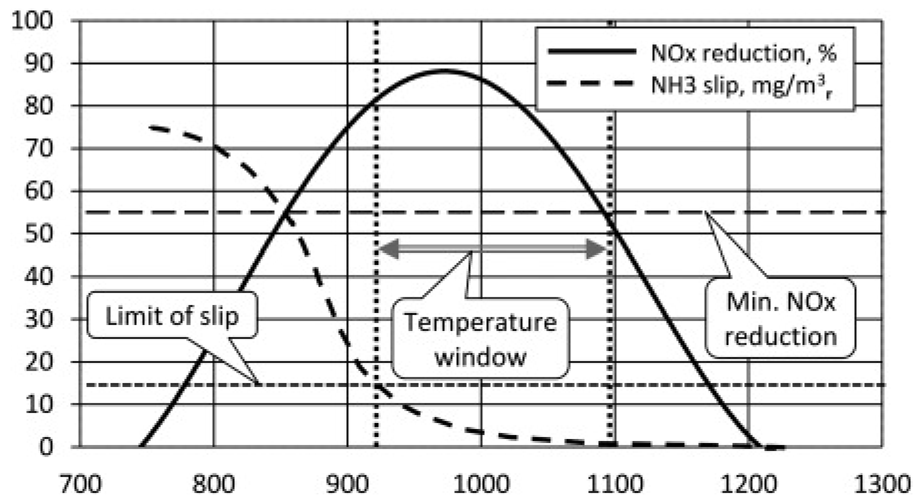

Figure 4-2. Exhaust Gas Temperature and NO_x Control Using SNCR.[13]

4.2.3 Low NO_x Burners

LNB control technology is principally found on boilers. An LNB controls air-to-fuel mixing to reduce the peak flame temperature in stages. By lowering the peak flame temperature, less NO_x is produced during combustion. Many boiler burners sold today are designed with at least LNB technology. "The two most common types of low NO_x burners being applied to natural gas boilers are staged air burners and staged fuel burners, or a combination thereof" (Appendix 3, p. 3).

4.2.4 Good Combustion and Maintenance Practices

Good combustion and maintenance practices involve operating the engine or boiler to maximize energy output or thermal efficiency while maintaining optimized oxygen levels to assure complete combustion. GCP can also involve running equipment in accordance with the

[13] *Environmentally Oriented Modernization of Power Boilers*, Chapter 4.4. Pronobis, M. 2020.

manufacturer's recommended settings and preventative maintenance schedules (Appendix 4, p. 2-2; Appendix 5, p. 2-3).

4.2.5 Operating Restrictions

Emergency engines can be subject to a variety of restrictions on the number of hours of operation; for example, the San Joaquin Valley Air Pollution Control District's Rule 4702 limits NO_x emissions from internal combustion engines with greater than 25 brake horsepower by limiting annual operating hours and allowing operations only for specific purposes (i.e., testing, maintenance, and emergency purposes) (Appendix 4, p. 2-3). DAQ did not consider operating restrictions a viable control technology for identifying RACT because they generally do not control NO_x or VOC emissions during emission unit operation. Such restrictions can, however, be used to avoid applicability, including RACT requirements.

4.2.6 Ultra-Low NO_x Burners for Boilers or Low Emission Control for Engines

Recent advancements in combustion technology have advanced LNB to higher levels of emission control, ultra-low NO_x burners (ULNB). This technology can reduce NO_x concentrations in a boiler exhaust to 9 ppm @ 3% O_2; however, the reduced NO_x emission level comes at the expense of increased carbon monoxide (CO) emissions (Appendix 3, Appendix B at p. 3). Many existing LNB cannot be fine-tuned to reach ULNB levels, so a replacement of the burners in a boiler is necessary to achieve ULNB.

Similar advances in combustion design have resulted in low emission control (LEC) engines. LEC, however, requires replacing the existing engine with a new one. DAQ did not consider replacement of engines a viable option for RACT because RACT is determined based on the design of the existing emission unit.

4.2.7 Flue Gas Recirculation

FGR is a control technology primarily applied to boilers. An FGR system reduces NO_x emissions in two ways by recirculating gas. "The gas suppresses formation of NO_x during combustion by reducing combustion temperatures by diluting the gas stream. It also lowers the oxygen concentration in the primary flame zone. An FGR system is normally used in combination with low NO_x burners to achieve a 60–90% reduce in NO_x emissions" (Appendix 5, p. 2-2). It may not be possible to retrofit this technology into all boiler types, and retrofitting may be limited by existing space constraints (Appendix 3, Appendix B at p. 3).

4.2.8 Exhaust Gas Recirculation

Exhaust gas recirculation (EGR) can reduce NO_x by 40% on low-load mobile diesels, but EPA notes that EGR requires external hardware retrofits, some additional controls, and possibly cooling/cleaning of exhaust. Other downsides include substantial fouling of heat exchanger and flow passages, increased maintenance, substantial increases in CO and smoke, and increased wear; as of 1993, EGR was not being offered for production compression ignition (CI) engines.[14] In

[14] "Alternative Control Techniques Document—NOx Emissions from Stationary Reciprocating Internal Combustion Engines," p. 5–85. EPA-453/R-93-032, July 1993.

addition, a National Resources Defense Council (NRDC) study reported that EGR results in fuel penalties of 0–5%, that it is among the most costly of available control options, and that it results in increased particulate emissions.[15]

4.2.9 Injection Timing Retardation

ITR is a good combustion practice that is applied principally on engines. The technology reduces the maximum combustion temperature and pressure, which decreases NO_x formation. Its use for NO_x emissions reduction comes with tradeoffs because ITR degrades performance and longevity and increases CO, PM, CO_2, and hydrocarbons (HC). EPA literature identifies these concerns, including a 3% fuel penalty.[16]

4.2.10 Air to Fuel Injection Ratio

Air-to-fuel injection ratio (AFR) can be used to control NO_x emissions from some types of engines. Literature indicates that even if it is available, it comes with substantial fuel penalties (up to 5%) and increases in HC and CO emissions, and is not very effective for diesel engines.[17]

4.2.11 Derating/Increasing Speed

EPA is unenthusiastic about this option, noting that derating results in substantial increases in brake-specific fuel consumption to the point that additional units would be required to compensate for the loss in output and HC and CO emissions from the derated unit would increase; increasing engine speed is equivalent to derating in loss of power and is not a feasible option for existing units.[18] EPA also points out that the reduction in NO_x emissions may be no more than the equivalent reduction in output, echoing the NAFB/manufacturer comment, and that NO_x emissions are less responsive to derating for turbocharged engines.[19]

4.2.12 Inlet Manifold Air Temperature (MAT) Adjustment/Aftercooler

Decreasing inlet manifold air temperature (MAT) reduces peak engine temperature, which reduces NO_x formation. When air is turbocharged, aftercooling can be used to cool the pressurized air before it enters the engine. Cooling requires hardware; an engine can be either air-cooled or water-cooled (which requires a cooling tower), but ambient temperatures may limit the amount of reduction that can be achieved (especially for air-cooled).[20] At least one study indicated that cooling intake air is an effective technique to reduce NO_x emissions, showing a reduction of

[15] "Cleaning Up Today's Dirty Diesels." NRDC 2005.

[16] "Control Techniques for Nitrogen Oxides Emissions from Stationary Sources – Second Edition," p. 4-67. EPA-450/1-78-001, January 1978.

[17] "Control Techniques for Nitrogen Oxides Emissions from Stationary Source – Second Edition," p. 4-66. EPA-450/1-78-001, January 1978.

[18] "Control Techniques for Nitrogen Oxides Emissions from Stationary Source – Second Edition," p. 4-63. EPA-450/1-78-001, January 1978.

[19] Emission Factor Documentation for AP-42, Vol. I, Section 3.4, "Large Stationary Diesel & All Stationary Dual Fuel Engines," p. 2-15. EPA, April 1993.

[20] Part 70 Operating Permit, Source No. 114, Section V.B.3.a, p. 34. Issued by DAQ on July 15, 2021. The OP requires using a turbocharger, but does not mention an aftercooler.

more than 50% NO_x in some operating conditions.[21] With a built-in air-cooling aftercooler, the temperature dropped from 356°F to 122°F, a delta of 234°F.[22]

Temperatures in Clark County can reach 115°F in the summer, but can drop to 30°F in the winter; air cooling requires less hardware than water cooling, but either can be used. The variation in ambient temperature makes it more difficult to determine control efficiency; however, EPA's 1978 control technology review indicates that for turbocharged diesels, the reduction in NO_x is approximately 0.3 • (ΔT°F)%.[23] Using this equation and a delta of 234°F yields a control efficiency of 0.3 • 234 = 70%.

The cost of using this control technology depends on whether there is a cooling tower and water available for cooling the air following the turbocharger. Assuming there is (or that air cooling is used), the cost is mainly a factor of the hardware (i.e., heat exchanger, piping) needed to cool the air following the turbocharger and the operating costs associated with it. There may also be a slight fuel penalty but, since that is difficult to determine, it was not included in DAQ's cost analysis for this control technology.

4.2.13 Water Injection (Direct Water Injection/Steam Injection)

According to EPA, water injection works by reducing peak combustion temperature and results in significant NO_x emissions reductions. Additional hardware is needed to inject water directly into the inlet manifold or cylinder, which can result in deposit buildup, degradation of lube oil, and cycling control problems. EPA indicates that at a 50% water/fuel ratio, there is a 25–35% decrease in NO_x with a 2–4% fuel penalty.[24] An increase in HC emissions also results from the lower peak temperature. NAFB indicated a problem with water destroying the protective oil film on the cylinders, but that can be prevented by using water vapor rather than water droplets. However, the work required to create an injection system for different engine types makes this approach more suited for the original equipment manufacturer (OEM) rather than a retrofit. A water/fuel emulsion is a better route, according to studies, and outlined in more detail below.[25]

In general, water can be introduced into the diesel combustion process using one of the following methods:

- Emulsified fuel,

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[21] "Experimental and Computational Investigation of Effects of Cooling Intake Air in NO_x Reduction and Performance of Diesel Engines." Lashkarpour, Bahlouli, Razavi and Milani. *Asian Journal of Applied Sciences, 4:30-41*, 2011.

[22] "Introduction of High Output Engine SAA12V140 for Generator," Komatsu Technical Report, Vol. 49, No. 152, 2003.

[23] "Control Techniques for Nitrogen Oxides Emissions from Stationary Source – Second Edition," Table 4-20. EPA-450/1-78-001, January 1978. The level of control varies from 0.1 to 0.4 • (ΔT°F)%, depending on whether the engine is a 2- or 4-cylinder, so 0.3 was selected as a conservative value.

[24] Emission Factor Documentation for AP-42, Vol. I, Section 3.4, "Large Stationary Diesel & All Stationary Dual Fuel Engines," Table 3.4-6. EPA, April 1993.

[25] "Water in Diesel Combustion." W.A. Majewski. DieselNet Technology Guide, 2002. Water in Diesel Combustion.

- In-cylinder water injection, or
- Water injection into the intake air (fumigation).

An emulsion is a system consisting of two immiscible liquids, one of which is finely dispersed in the other. In all water/diesel fuel emulsions of practical importance, water is dispersed in the form of fine droplets in the continuous diesel fuel phase: this type of emulsion is often referred to as “water-in-fuel” emulsion. In the opposite configuration, where fuel is dispersed in the continuous water phase, water would be much more likely to contact the cylinder liner surface and other metal parts, leading to corrosion and engine problems.

In practice, running an engine on water-fuel emulsion makes it possible to reduce NO_x by up to about 50%, with the required water quantity being about 1% for each percentage point of NO_x reduction [Holtbecker 1998].[26] The limiting factor for water emulsions is the delivery capacity of the injection system. If emulsions are used without engine modifications (e.g., to substitute regular fuel in existing engines), the maximum quantity of water and the degree of NO_x reduction are both limited to around 10–20%; even then, the engine may not be able to reach its rated power, running in effect at a slightly derated condition.

Emulsions are distinguished from other methods of water addition in that water, being incorporated into the fuel spray droplets themselves, is introduced directly into the combustion flame area where emissions are formed. In addition to the NO_x benefit, which in all methods is attributed primarily to the water lowering the combustion temperature, emulsions result in enhanced fuel spray atomization and mixing. Enhanced mixing that extends throughout the diffusion flame can bring impressive reductions of PM emissions. As a result, water-fuel emulsions are one of the rare diesel emission control strategies that can simultaneously reduce NO_x and particulate matter (PM) emissions with no, or only a small, fuel economy penalty. Reduction of PM emissions by emulsions has not been as thoroughly researched as NO_x reduction; nevertheless, the achievable effectiveness of PM reduction appears to be more than twice that of NO_x reduction.

In-cylinder injection of water requires a separate, fully independent injection system, preferably under electronic control. This method offers the capability to inject very large quantities of water without the need to derate the engine. The system also allows operators to switch the water injection on and off, as may be needed, without affecting engine reliability. Direct water injection needs to be carefully optimized with respect to injection timing, water consumption, emissions, and other parameters. This flexibility in optimizing parameters allows this control approach to achieve NO_x reductions similar to those seen in emulsion systems, despite the fact that water is not introduced directly into the diesel flame area as an integral part of the spray. However, any PM emission reductions do not match those seen with emulsified fuels. The complex development work required for water injection systems in different engine types makes this approach more suited for OEM than for retrofit applications.

[26] Cited in: W. Addy Majewski, Water in Diesel Combustion, DieselNet Technology Guide, dieselnet.com/tech/engine_water.php, 2002.

Fumigation, meaning the introduction of water into the intake air, is the simplest method of water addition. This method offers very little control over injection parameters, such as timing or spatial coordinates. For this reason, observed NO_x reductions tend to be lower than with emulsions or direct injection. Fumigation typically reduces NO_x emissions by 10% for each 20% addition of water to the fuel [Holtbecker 1998].[27]

If fumigated water does not completely evaporate in the intake air, it will impinge on the cylinder walls, causing disintegration of the lube oil film and engine damage. A safer approach is to fumigate water vapor rather than water liquid. Water vapor may be generated using waste heat from the engine, such as from the exhaust gas and/or compressed charge air. Another possibility is steam, which may be available in certain stationary engine applications.[28]

In-cylinder injection is more suitable for OEM and requires development to retrofit on existing engines. It is unlikely to be economically reasonable for existing emission units. For boilers, "[b]ecause of low initial cost, this technique is considered particularly effective for small single-burner packaged boilers operated infrequently. In these applications, the oil gun positioned in the center of the natural gas ring burner is used to inject the water at high pressure. The amount of water injected normally varies between 25 and 75 percent of the natural gas feed rate, on a mass basis. However, the technique has some important environmental and energy impacts. For example, CO emissions increase because of the quenching effect on combustion, and the thermal efficiency of the boiler decreases because the moisture content of the flue gas increases, contributing to greater thermal losses at the stack. Another concern related to this technique is its potential for unsafe combustion conditions that can result from poor feed rate control."[29]

A literature search produced no information on the technical feasibility of adding water or steam injection to boilers with LNB—and whether the amount of NO_x reduction would be less, since LNB already have reduced emissions—and very little cost information. One study is cited for package fire-tube boilers: for a 33.5 MMBtu/hr boiler and a capacity factor of 0.33, the CE in 1992 dollars is \$3,903/ton NO_x removed.[30] The study includes both Oxygen Trim and Water/Steam inject systems and does not separate out the costs between the two, since both are needed to get the reported NO_x reductions. Correcting that to 2022 costs using the Chemical Engineering Plant Cost Index (CEPCI), $CE_{2022} = \$3{,}903_{1992} \cdot (\$824.5_{2022}/\$358.2_{1992}) = \$8984/\text{ton}$.

4.2.14 Water/Fuel Emulsions

The literature indicates this is a viable option, even more so than water injection; one source indicates that NO_x control is limited to 20% without engine modifications, but reductions of 50%

[27] Cited in: W. Addy Majewski, Water in Diesel Combustion, DieselNet Technology Guide, dieselnet.com/tech/engine_water.php, 2002.
[28] W. Addy Majewski, Water in Diesel Combustion, DieselNet Technology Guide, 2002. Online at: Dieselnet.com/tech/engine_water.php.
[29] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-43.
[30] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. D-3.

are possible with modifications.[31] Another study indicates that emissions reductions up to 80% are possible.[32]

Calculated costs for large engines can range from $4.4/kW to $19.2/kW, with a higher per kW cost for smaller engines.

Emulsified diesel cost about 4.4% more than regular diesel in Europe in 2015, so that cost differential is assumed: for example, if diesel costs $5/gallon, then emulsified diesel costs $5.22/gal. The gallons of fuel used per year can be estimated using the size of the engine and hours of operation;[33] taking the gallons per year times a delta of $0.22/gal yields the cost of using emulsified diesel.[34]

The stability of the emulsion used could be an issue. Only a 10% water emulsion is stable over fairly long periods (at least 35 days with no water separation).[35] This might require replacing unused fuel, resulting in additional expense.

4.2.14.1 Engine Performance Management System

The US. Nuclear Regulatory Commission (NRC) points out that manufacturers' monitoring and maintenance guidance is based on long periods of running time and is at times unhelpful and/or damaging if followed for emergency generators.[36] In this way, an engine performance management system (EPMS) is different from GMP/GCP. The NRC recommends (or, in some cases, mandates) more extensive monitoring and different maintenance procedures than would constitute a comprehensive EPMS for emergency diesel generators; their guidance includes monitoring temperatures, quality of fuel (diesel degrades after a year), CO emissions that indicate the degree of combustion, and so forth.

EPMS alone does not appear to reduce NO_x emissions, and DAQ located no data estimating improved efficiency or NO_x emissions reduction potential. Because the degree of emissions reductions achievable through this work practice is unknown and appears negligible, DAQ does not consider it a viable technology for RACT.

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[31] W. Addy Majewski, Water in Diesel Combustion, DieselNet Technology Guide, dieselnet.com/tech/engine_water.php, 2002.

[32] Issa, M., Ibrahim, H., Ilinca, A. and Hayyani, M.Y. (2019) A Review and Economic Analysis of Different Emission Reduction Techniques for Marine Diesel Engines. Open Journal of Marine Science, 9, 148-171. See Table 5, p. 162. https://doi.org/10.4236/ojms.2019.93012

[33] Diesel Service & Supply | 625 Baseline Road, Brighton, Colorado 80603, sales@dieselserviceandsupply.com | www.dieselserviceandsupply.com Toll-Free: 800-853-2073 | Main Office: 303-659-2073 | Fax: 720-685-7920

[34] "Penetration Prospects of Emulsified Fuel in the Greek Oil Market," in *Proceedings of the 14th International Conference on Environmental Science and Technology,* Rhodes, Greece, September 2015. Tyrovola, Feligiannis, Dodos, and Zannikos.

[35] "Diesel-Water Emulsion, an Alternative Fuel to Reduce Diesel Engine Emissions. A Review." D. Scarpete, University of Galati, Romania.

[36] NRC 2011. ML11229A426-0420-E111. Contains 14 chapters addressing use of emergency diesel generators at nuclear plants, with emphasis on making certain the units will start and operate as expected in an emergency. Chapter 12 focuses on the parameters to monitor and why they are important. https://www.nrc.gov/docs/ML1122/ML11229A061.html

4.2.14.2 High-Pressure Fuel Injection

A literature review found some articles indicating NO_x reductions may occur when increasing injection pressure is used with retarded timing and other injection techniques. Generally, higher injection pressure (using larger area nozzles) promotes mixing and shortens combustion time, resulting in higher combustion chamber temperatures. Increased combustion temperature increases NO_x emissions; in addition, ultra-high-pressure injection is more appropriate for manufacturers to build into their engines than for retrofit.[37] DAQ thus does not consider it a viable control technology for RACT.

4.3 NELLIS AIR FORCE BASE (NAFB)

NAFB (Source ID: 114) is permitted as a major (Part 70) source for NO_x, a synthetic minor source for VOC, PM_{10}, $PM_{2.5}$, CO, and HAP, and a minor source for SO_2. It is also a source of GHG. The facility includes a stationary source category which, as of August 7, 1980, was regulated under Section 111 of the Act (“Asphalt Plants”); therefore, fugitive emissions from the asphalt plant were included in the source status determination. All the activities and emission units (EUs) at NAFB are classified as Standard Industrial Classification (SIC) code 9711 and North American Industry Classification System (NAICS) code 928110, both titled “National Security.”

Although it is treated as a single stationary source for permitting purposes, NAFB’s emission units and activities are divided into three geographic areas that vary in size and purpose. Area I, the Main Base, consists of the flight line and a wide variety of commercial and industrial operations that support the base’s mission. Area II, located east of the Main Base, includes the munitions storage area and the Red Horse Squadron complex (along with its mineral processing, asphalt batch plant, and concrete batch plant activities). Area III is a 1.9-square-mile portion north of the Main Base that includes the bulk fuels storage area, Security Police Squadron facilities, open space, and support facilities. According to NAFB, the most recent ATC (issued 10/13/22) lists the NO_x PTE as 200.47 tpy.

DAQ’s RACT methodology (Appendix 1) notes that although NAFB has a NO_x PTE of around 200 tpy, it had only 19.81 tpy of actual NO_x emissions in 2017 (about 10% of PTE). In its RACT analysis, NAFB included all units with a PTE equal to or greater than 5 tpy as listed in the RACT methodology and the NAFB OP, plus a planned emergency generator for Building 1771 that has not yet been installed but has received a unit number (G188). NAFB noted that Unit G141 was permitted, but was never installed and will not be (it is the wrong size), and that Unit G176 has not yet been installed, so has no actual emissions, but was still included in the RACT analysis.

Altogether, NAFB conducted NO_x RACT analyses for a single non-emergency stationary engine (A032); seven emergency-use stationary engines (generators) (G009, G010, G032, G033, G041, G176, and G188); and two aircraft engine test cells (N001 and N002). All of the generators are diesel-fired and considered standby generators, so are allowed only limited use, and all are

[37] Fayad, M.A. Effect of Fuel Injection Strategy on Combustion Performance and NO_x/Smoke Trade-Off Under a Range of Operating Conditions for a Heavy-Duty DI Diesel Engine. *SN Appl. Sci.* 1, 1088 (2019). https://doi.org/10.1007/s42452-019-1083-2

operated at levels far below their potential use.[38] The DAQ RACT analyses in Section 4.3 are based on NAFB's analyses, supplemented as needed.

Most of the NAFB RACT analyses were for generators. NAFB used a more complete list of potential NO_x control retrofit technologies than most facilities, including the replacement of existing generators. Replacing an entire emission unit, however, is not required in RACT analyses, which are limited to controls available for the existing emission unit, so DAQ eliminated further consideration of that option for this RACT analysis.[39]

4.3.1 NO_x RACT for Unit A032

4.3.1.1 Control Technology Analysis

This diesel-fired generator (Appendix 2, p. 11; analysis indicates it is a low-load mobile diesel) supports the aggregate plant at the base; it has an annual operating limit of 2,080 hours, but was not used in 2021 and there were no plans to use it in 2022. Emissions from 2017–2021 ranged from 0.0 to 0.39 tpy NO_x, and the highest annual use of the engine in the past five years was in 2018 (102 hours). The unit is turbocharged. Its existing NO_x controls are GCP and GMP, typical for emergency generators.

Appendix 2 contains the NAFB RACT analysis. Table 4.3-1 lists the potentially available control technologies identified by NAFB. The table includes DAQ's analysis of NAFB's information, along with supplemental information on the availability and costs of the emissions controls and a conclusion on whether each control qualifies as RACT. NAFB proposed accepting an operating limit of 1,200 hours, which would reduce the current PTE of A032 from 8.06 tpy to 3.41 tpy to meet RACT requirements. DAQ found that the existing control technology requirements—turbocharging and ignition timing retardation—qualify as RACT, and proposes to establish a design and operating standard as RACT in lieu of restricting hours of operation. NAFB may, at its option, elect instead to accept an enforceable reduction in operating hours of A032 to avoid the RACT requirements.

The CE analyses in Table 4.3-1 are mostly first-order approximations based on information available in the literature; in a few cases, vendor information on cost or applicability was available. DAQ did not correct costs for inflation unless the initial CE calculation was below the CE threshold. Detailed cost calculations are in Appendix 9.

Table 4.3-1. NO_x RACT Analyses for Unit A032[40]

CT #	Control Technology	RACT	Discussion
1	SCR	No	This is a small unit (250 hp) that operates well below PTE.

[38] A032, for example, is authorized to operate 2,080 hours per year, but the highest operating level in the last five years was 102 hours in 2018.

[39] Even if replacement was a required option, the cost effectiveness (CE) analyses conducted by NAFB for replacing the generators with lower-emitting generators demonstrated that the cost (in $/ton NO_x decrease) was far higher than the threshold of $5500/ton.

[40] NAFB noted on 1/31/22 that this unit is not operational and there are no current plans to operate this unit in the future, but since it is still permitted, DAQ conducted a RACT analysis for the unit.

CT #	Control Technology	RACT	Discussion
			Intermittent operations of A032 would decrease control efficiency of SCR compared to steady-state operations. DAQ calculates a CE of $37,001/ton NO_x removed, more than 6 times higher than the $5,500/ton threshold. DAQ concurs this control technology does not qualify as RACT because it is not cost-effective.
2	SNCR	No	NAFB could not find examples of SNCR being used and concluded the control technology is not technically feasible for A032. Literature indicates that SNCR, though having a lower capital and operating cost, is not available for diesel engines because the technology operates best at temperatures of 1600–2000°F, and diesel engine exhaust gas ranges from 800–1200°F.[41] The exhaust gas temperature is too low for SNCR to be effective (Figure 4-2).[42] SNCR also needs a fuel-rich engine operation or use of reducing agents, so its use is limited to rich-burn engines. DAQ finds this control technology is not technically feasible for A032.
3	Dry Low NO_X (DLN) and SoLoNO$_X$ (SLN)	No	NAFB indicates these technologies are primarily for turbines and it found no examples for use on engines similar to A032. DAQ also could not locate articles, documents, or websites showing DLN or SLN use on diesel engines. DAQ concurs that this control technology is not technically feasible for A032.
4	Turbocharging	Yes	A turbocharger increases the power output of an engine by allowing more air to enter the combustion chamber. The increased air reduces the maximum combustion temperature and pressure, which decreases NO_x formation. A032 is currently equipped with a turbocharger and no additional cost is estimated to use this technology. DAQ concludes that use of a turbocharger qualifies as RACT. Turbocharging combined with EGR could further reduce NO_x emissions, but EGR has drawbacks (see #7).[43]
5	GCP, GMP	Yes	These are the most common RACT determinations in the RBLC and already implemented on A032 via its Title V OP.[44] DAQ finds this control technology available and cost-effective because NAFB would incur no additional costs to continue with these practices.
6	Pre-stratified charge	No	According to NAFB, the manufacturer says this control technology is not available. EPA documents support NAFB's analysis, indicating this technique is for spark ignition engines, not compression engines.[45] DAQ agrees this control technology does not qualify as RACT because it is not available.
7	EGR	No	DAQ makes no determination on availability, but agrees this control technology does not qualify as RACT because the potential energy and collateral pollutant disbenefits outweigh the benefit of NO_x emission reductions. See general discussion in Section 2.1.6.
8	ITR	Yes	The NAFB OP requires operating A032 with ITR,[46] which DAQ concludes qualifies as RACT. If the unit had not already been equipped for ITR, retrofit installation would have resulted in a CE of

[41] Marek Pronobis, Environmentally Oriented Modernization of Power Boilers, 2020, Chapter 4.4.2.

[42] Emission Factor Documentation, p. 2-18.

[43] Dond, DK, Gulhane, NP. Effect of a turbocharger and EGR on the performance and emission characteristics of a CRDI small diesel engine. *Heat Transfer*. 2022; 51: 1237- 1252. doi:10.1002/htj.22350

[44] Condition V.B,3.g. states: "The permittee shall operate and maintain all generators in accordance with the manufacturer's O&M manual for emissions-related components." DAQ assumes that this represents GCP and GMP.

[45] EPA-453/R-93-032, Alternative Control Techniques Document-NO_X Emissions from Stationary Reciprocating Internal Combustion Engines, July 1993, p. 5-14.

[46] Source No. 114, Title V Operating Permit, issued 6/15/21. Condition V.B.3.c, p. 34.

CT #	Control Technology	RACT	Discussion
			$6,674/ton,[47] making this control technology not cost-effective.
9	AFR adjustments	No	DAQ makes no finding on availability, but concludes this control technology does not qualify as RACT because the energy and collateral pollutant disbenefits outweigh the benefits of the potential emissions reductions.
10	Derating / increasing speed	No	DAQ finds this control technology does not qualify as RACT because the energy and collateral pollutant disbenefits outweigh the potential for RACT emissions reductions.
11	MAT adjustment / after-cooler	No	DAQ estimates the CE for retrofitting a cooler on A032 at $15,000/ton. DAQ concludes this control technology is available but not cost-effective, so does not qualify as RACT.
12	DWI	No	The CE estimated for this 250-hp engine was based on much larger engines (6,000+ hp), giving a NO_x reduction of 90% at $10,279/ton, twice the threshold.[48] DAQ finds this control technology is not cost-effective, so does not qualify as RACT.
13	Water/fuel emulsions	No	Extrapolating from a 6,000-hp engine to a 250-hp one (equivalent to 186 kW) gives a rough $25/kW capital cost for the smaller engine. At 186 kW, A032 would have a $4,650 capital cost. There are also annual operating costs for using emulsified diesel: it cost about 4.4% more than regular diesel in Europe in 2015 (if regular diesel cost $5/gallon, emulsified diesel cost $5.22/gal). Further assuming 500 hrs/yr of operation for the 250-hp diesel engine yields about 6,274 gal/yr[49] which, with a delta of $0.22/gal, equals $1,479/year.[50] DAQ calculated a CE of $61,754/ton, so concludes this control technology is not RACT because it is not cost-effective.
14	EPMS	No	DAQ finds this control technology does not qualify as RACT because the amount of additional NO_x emissions reductions through use of an EPMS system is likely negligible.
15	High-pressure fuel injection	No	DAQ concludes this control technology does not qualify as RACT because the effect on reducing NO_x emissions and ability to retrofit the technology for existing emission units is highly uncertain.
16	Conversion to natural gas from diesel	No	NAFB's security directive prohibits reliance on natural gas for standby generation.[51] DAQ thus finds this control technology is not available.
17	Conversion to dual fuel (diesel/natural gas)	No	NAFB's security directive prohibits reliance on natural gas for standby generation; however, dual fuels might be acceptable by allowing use of diesel when natural gas is not available. Costs would include converting the generator to dual fuel and the piping needed to supply the unit with natural gas. Conversion cost for small diesels ranges from $7,000 to $12,000.[52] NO_x reductions of 20–30% are

[47] Based on data from EPA's ACT for NO_x emissions from ICE engines, p. 2-42, Table 2-14.

[48] Issa, M., Ibrahim, H., Ilinca, A. and Hayyani, M.Y. (2019) A Review and Economic Analysis of Different Emission Reduction Techniques for Marine Diesel Engines. Open Journal of Marine Science, 9, 148-171. https://doi.org/10.4236/ojms.2019.93012

[49] Diesel Service & Supply | 625 Baseline Road, Brighton, Colorado 80603, sales@dieselserviceandsupply.com | www.dieselserviceandsupply.com Toll-Free: 800-853-2073 | Main Office: 303-659-2073 | Fax: 720-685-7920

[50] *Proceedings of the 14th International Conference on Environmental Science and Technology Rhodes, Greece, 3-5 September 2015;* PENETRATION PROSPECTS OF EMULSIFIED FUEL IN THE GREEK OIL MARKET, TYROVOLA TH., DELIGIANNIS A., DODOS G.S. AND ZANNIKOS F.

[51] NAFB included a copy of the directive in its RACT analysis.

[52] https://finddiffer.com/how-much-does-it-cost-to-convert-a-diesel-engine-to-gas/

CT #	Control Technology	RACT	Discussion
			expected.[53] DAQ calculated a CE of $6,207/ton—slightly above the threshold—assuming no increase in maintenance costs and only a $2,000 cost to connect to natural gas.[54] DAQ finds this control technology does not qualify as RACT because it is not cost-effective.
18	Alternative fuels (other than natural gas)	NA	Literature indicates that other fuels are not available for these engines. Methanol and liquified natural gas (LNG) are the main alternatives besides emulsions. Methanol has serious corrosive and toxic problems, is costly, and can be readily contaminated with water, although NO_x reductions can reach 60%. LNG requires huge investments for storage and installation and has high CO emissions.[55] DAQ finds that alternative fuels are not RACT for these emergency generators because the costs and potential collateral pollutant disbenefits outweigh the benefits of potential emissions reductions.

4.3.1.1.1 RACT Emissions Limitation

DAQ determined that turbocharging, in combination with ITR, CGP, and GMP, qualifies as RACT for Unit A032 because the technology is feasible and cost-effective, since it is already required. It is not feasible, however, to establish an emissions limitation for any of these control technologies. Turbocharging represents a design standard, while ITR is an operational standard. DAQ proposes to adopt the following requirements for RACT:

1. NAFB shall operate A032 with turbochargers.

2. NAFB shall operate A032 with ITR.

3. NAFB shall operate the generator in accordance with manufacturer's recommended O&M specifications.

No additional NO_x emissions reductions are expected from compliance with RACT requirements.

NAFB concluded its RACT analysis by proposing a reduction in Unit A032's hours of operation, from the currently authorized 2,080 hours to 1,200 hours per year. This action would reduce A032's PTE to below 5 tpy. DAQ does not consider reduced hours of operation a potential control technology because it does not reduce emissions during times of operation. Because A032 already satisfies RACT requirements, NAFB need not accept the proposed operational restrictions; however, if NAFB wishes to avoid establishing RACT requirements on A032 (even though they impose no additional control), it may apply to reduce the PTE of the emissions unit to below 5 tpy.

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[53] Talus Park, Dual fuel conversion of a direct-injection diesel engine, West Virginia University Master's Thesis, 1999.

[54] This cost may be underestimated.

[55] Issa, M., Ibrahim, H., Ilinca, A. and Hayyani, M.Y. (2019) A Review and Economic Analysis of Different Emission Reduction Techniques for Marine Diesel Engines. Open Journal of Marine Science, 9, 148-171. https://doi.org/10.4236/ojms.2019.93012

4.3.2 Emergency Generators

4.3.2.1 Control Technology Analysis

NAFB operates eight emergency generators with a PTE above 5 tpy, and included specifications for each of these engines in its RACT analysis (Appendix 2). Three engines are not included in this analysis. One unit (#141) was incorrectly sized when purchased, so rather than operate it, NAFB uses it for spare parts. EU G176 is a new engine that was installed with BACT. DAQ determined the existing BACT analysis remains current and satisfies RACT requirements for this unit. An additional emission unit is awaiting an ATC Permit that will address any RACT requirements for the unit when it is issued.

Since the eight emergency generators are similar in size and planned operation, both NAFB and DAQ performed a single analysis representing all eight. Appendix 2 contains the NAFB RACT analysis; DAQ included the potentially available control technologies identified by NAFB for the eight emergency engines in Table 4.3-2. The table also includes DAQ's analysis of information provided by NAFB, along with supplemental information on the availability and costs of the emissions controls and DAQ's conclusion on whether the control qualifies as RACT. Appendix 9 provides detailed cost calculations.

DAQ grouped the control technologies by type: CTs 1–3 are add-on controls; CTs 4–15 are modifications to the emission unit or its operation; and CTs 16–18 are fuel switch options, including conversion of the units to allow use of alternative fuels. NAFB included emission unit replacement as potentially available control technology options; however, DAQ does not consider replacement an available control technology because RACT is defined relative to the emission unit under review, and replacement does not result in emissions control for an existing unit. DAQ thus eliminated replacement options as RACT from further review.[56]

Table 4.3-2. NO_x RACT Analyses for Emergency Generators (G009, G010, G032, G033, G041)

CT #	Control Technology	RACT	Discussion
1	SCR	No	DAQ performed a cost-effectiveness analysis for G041, a small unit (1,220 hp) with the highest annual emissions of all emergency engines, so most likely to have a CE below the threshold. This conservative analysis resulted in a CE of $7,754/ton of NO_x removed, more than the $5,500/ton threshold. DAQ determined SCR is not RACT because it is not cost-effective.

[56] Notably, although DAQ finds replacing an existing emission unit and reducing hours of operation are not control technology options for RACT, a major source, at its election, could opt to use these strategies to meet certain emissions limitations established based on RACT or to avoid applicability by reducing PTE.

CT #	Control Technology	RACT	Discussion
2	SNCR	No	NAFB could not find examples of SNCR being used, so considered it not technically feasible. Literature indicates SNCR is not available for diesel engines because it operates best at temperatures of 1600–2000°F and diesel engine exhaust gas ranges from 800-1200°F.[57] SNCR also needs a fuel-rich engine operation or the use of reducing agents; CI diesel engines are generally lean-burning. In addition, exhaust gas temperature makes SNCR unsuitable (Figure 4-1).[58] DAQ finds that SNCR does not qualify as RACT because it is not an available control technology.
3	DLN and SLN	No	NAFB indicates these technologies are primarily for turbines, and no examples for emergency engines were found. DAQ also could not find articles, documents, or websites showing use of either on diesel engines. DAQ thus finds that DLN and SLN are not commercially available for application to these emergency engines.
4	Turbocharging	Yes	NAFB's RACT analysis indicates that these emergency generators are currently equipped with turbochargers.[59] DAQ finds this control technology qualifies as RACT because it is both available and cost-effective.
5	GCP and GMP	Yes	These are the most common RACT determinations in the RBLC and already implemented on these units through the OP.[60]
6	Pre-stratified charge	No	According to NAFB, the manufacturer says this technology is not applicable or available. EPA documents support NAFB's analysis, indicating this technique is for spark ignition engines, not compression engines.[61] DAQ agrees this control technology does not qualify as RACT because it is not available.
7	EGR	No	DAQ makes no determination on the availability of this control technology, but agrees it does not quality as RACT because the potential energy and collateral pollutant disbenefits outweigh the benefit of NO_x emission reductions (Section 2.1.6).
8	ITR	Yes for G032 and G033; No for other units	The NAFB RACT analysis concludes ITR is not a desirable control technology because it degrades performance and longevity. The literature backs this up, indicating increases in CO, PM, and HC emissions and a fuel penalty of 3%. DEQ CE calculations result in a CE of $30,740/ton, much higher than the $5,500/ton threshold.[62] However, the OP already requires it for G032 and G033, so it is considered RACT for those units. DAQ concludes that ITR does not qualify as RACT for the other units because the energy and collateral pollutant disbenefits outweigh potential emission reductions, and the control technology is not cost-effective for the other engines.

[57] Marek Pronobis, Environmentally Oriented Modernization of Power Boilers, 2020, Chapter 4.4.2.

[58] Emission Factor Documentation, p. 2-18.

[59] The NAFB RACT analysis states that all these emergency generators are equipped with turbochargers (p. 16). The Part 70 Operating Permit requires all 100+HP generators be equipped with a turbocharger and aftercoolers. *See* Condition V.B.3.a, p. 34, Part 70 Operating Permit, Source No. 114, issued June 15, 2021.

[60] From the Title V permit (Condition V.B.3.g, p. 35):

> The permittee shall operate and maintain all generators in accordance with the manufacturer's O&M manual for emissions-related components.

[61] EPA-453/R-93-032, Alternative Control Techniques Document-NO_X Emissions from Stationary Reciprocating Internal Combustion Engines, July 1993, p. 5-14.

[62] Based on data from EPA's ACT for NO_X emissions from ICE engines, p. 2-42, Table 2-14.

CT #	Control Technology	RACT	Discussion
9	AFR adjustments	No	NAFB states that this technology would reduce power capability, which Air Force mission requirements would not allow. DAQ makes no finding on the availability of this control technology, but finds that it does not qualify as RACT because the energy and collateral pollutant disbenefits outweigh the benefits of the potential emissions reductions.
10	Derating / increasing speed	No	DAQ finds that this control technology does not qualify as RACT because the energy and collateral pollutant disbenefits outweigh the potential NO_x emission reductions
11	MAT adjustment / after-cooler	Yes	NAFB is required to use air cooling on these emergency generators.[63] DAQ concludes that air cooling qualifies as RACT because it is available and cost-effective.
12	DWI	No	The CE estimated for these emissions, based on much larger engines (6000+ hp), gives a NO_x reduction of 90% at $10,279/ton, twice the threshold.[64] DAQ concludes this technology is not RACT because the environmental impacts associated with increased water use and potential collateral pollutant disbenefits outweigh the potential for emissions reductions, and because it is not cost-effective.
13	Water/fuel emulsions	No	DAQ estimated this CE at $13,323/ton, so concludes this is not RACT because it is not cost-effective.
14	EPMS	No	DAQ finds this control technology does not qualify as RACT because the amount of additional NO_x emissions reductions through use of an EPMS system is likely negligible.
15	High-pressure fuel injection	No	DAQ finds this control technology does not qualify as RACT because the effect on reducing NO_x emissions and ability to retrofit the technology for existing emission units is highly uncertain.
16	Conversion to natural gas from diesel	No	NAFB's security directive prohibits reliance on natural gas for standby generation (footnote #48; Appendix 2). DAQ finds this control technology does not qualify as RACT because it is not technically feasible.
17	Conversion to dual fuel (diesel/natural gas)	No	NAFB's security directive prohibits reliance on natural gas for standby generation; however, dual fuels might be acceptable by allowing use of diesel when natural gas is not available. Costs would include converting the generator to dual fuel and the piping needed to supply the unit with natural gas. Conversion cost for small diesels with turbochargers ranges from $8,000–$12,000.[65] Reductions of 20–30% NO_x are expected.[66] DAQ calculated a CE of $8,476/ton, assuming $2,000 to connect to natural gas.[67] DAQ finds this control technology does not qualify as RACT because it is not cost-effective.

63 Condition V.B.3.a.: Generators greater than 100 hp (EUs: G004, G009, G010, G029 through G033, G035a, G041, G046 through G051, G064, G067 through G069, G073, G077, G080, G090 through G094, G097, G103, G121, G130 through G132, G136, G137, G139, G141, G142, G149, G154, A053, A076, G161 through G163, G165, G166, and G172 through G182) shall be equipped with turbochargers and aftercoolers.

64 Issa, M., Ibrahim, H., Ilinca, A. and Hayyani, M.Y. (2019) A Review and Economic Analysis of Different Emission Reduction Techniques for Marine Diesel Engines. Open Journal of Marine Science, 9, 148-171. https://doi.org/10.4236/ojms.2019.93012

65 https://finddiffer.com/how-much-does-it-cost-to-convert-a-diesel-engine-to-gas/

66 Talus Park, Dual fuel conversion of a direct-injection diesel engine, West Virginia University Master's Thesis, 1999.

67 On 1/31/23, NAFB commented that natural gas is only available in the area for 6 of the 8 engines and that there are no lines to engines, so the cost to bring NG lines to the engines would be considerably higher than the assumed $2000/engine..

CT #	Control Technology	RACT	Discussion
18	Alternative fuels (other than natural gas)	No	NAFB states that alternative fuels are not demonstrated or available for these engines, and the literature supports this conclusion. Methanol and LNG are the main alternatives besides emulsions. Methanol has serious corrosive and toxic problems, is costly, can be readily contaminated with water, and can increase greenhouse gas emissions. LNG requires huge investments for storage and installation, and increases CO emissions.[68] DAQ concludes that these alternative fuels are not RACT because LNG is not cost-effective and the collateral pollutant emissions disbenefits outweigh potential emissions reduction benefits.

4.3.2.2 RACT Emissions Limitation

NAFB concluded that RACT is no additional add-on NO_x emissions control and proposes to follow GCP and GMP to satisfy BACT requirements. For the reasons discussed in Table 4.3-2, DAQ finds the existing emissions controls, consisting of turbocharging and MAT adjustment / aftercooler, qualify as RACT. Similar to Unit A032, it is not feasible to establish an emissions limitation for use of either control technology. DAQ proposes that NAFB continue to operate G009, G010, G032, G033, & G041 with turbochargers and aftercoolers. No additional NO_x emissions reductions are expected from compliance with RACT requirements.

4.3.3 Aircraft Engine Test Cells (N001 and N002)

Also termed "hush houses," these test cells are used to conduct off-wing aircraft engine diagnostics and testing. NO_x emissions come from firing the aircraft engines, which are the F100 series: a twin spool, axial flow, afterburning turbofan engine. It has a three-stage fan driven by a two-stage low-pressure turbine and a ten-stage compressor driven by a two-stage high-pressure turbine. Allowable NO_x emissions are 46.42 tpy, compared to the five-year high of 12.90 tpy in 2019 and a five-year average of 9.622 tpy.

NAFB reviewed the RBLC data and found three similar facilities with RACT determinations of no additional controls or practices other than the "preventive requirement of good management practices." They also noted no control measures were found for aircraft engine testing or similar sources in EPA's Menu of Control Measures (2013). NAFB therefore determined that RACT is no additional controls.

An on-line search on hush house controls showed at least one company in the business of providing noise control for hush houses offers an SCR to control NO_x emissions.[69] DAQ found no information on the internet specific to hush house SCR control size or cost. Compared to diesel engine exhaust, the exhaust from F100 turbofan engines is hotter (up to 3,000°F),[70] requiring

[68] Issa, M., Ibrahim, H., Ilinca, A. and Hayyani, M.Y. (2019) A Review and Economic Analysis of Different Emission Reduction Techniques for Marine Diesel Engines. Open Journal of Marine Science, 9, 148-171. https://doi.org/10.4236/ojms.2019.93012

[69] https://www.cecoenviro.com/wp-content/uploads/2022/06/Burgess-Aarding-Silencer-and-acoustical-technology.pdf

[70] 07-342, A National Historic Context for the Hush Houses and Test Cells on Department of Defense Installations, Jayne Aaron, LEED AP, November 2009

mixing with cool air to avoid damaging the noise reduction equipment, and has a higher volume, especially in the afterburner phase of operation. Exhaust mass ranges in one article were 18.8, 22.32, and 167.688 kg/sec at the three main test modes (idle, military, and afterburner).[71] DAQ therefore concludes that RACT is the current OP requirement of applying best management practices.[72]

4.4 CAESARS ENTERTAINMENT, LAS VEGAS

Caesars (Source ID: 257) owns and operates several adjacent and contiguous hotels and casinos, along with a convention center. DAQ reviewed the following properties for this RACT analysis:

- Harrah's Las Vegas, 3475 S. Las Vegas Blvd.
- Flamingo Las Vegas, 3555 S. Las Vegas Blvd.
- Horseshoe Las Vegas, 3645 S. Las Vegas Blvd. (formerly Bally's)
- Caesars Palace, 3570 S. Las Vegas Blvd.
- The Cromwell Hotel, 3595 S. Las Vegas Blvd.
- Paris Las Vegas, 3655 S. Las Vegas Blvd.
- The LINQ, 3535 S. Las Vegas Blvd.
- High Roller (observation wheel in the LINQ complex), 3545 S. Las Vegas Blvd.
- Planet Hollywood Las Vegas, 3667 S. Las Vegas Blvd.
- Battista's Hole in the Wall restaurant, 4041 Audrie St.
- Caesars Forum conference center, 3911 Koval Lane.

Caesars's PTE for the consolidated properties is 440.10 tons per year of NO_x emissions and 26.76 tons per year of VOC. Only NO_x emissions exceed both the 40 CFR Part 70 major-source and moderate area major-source thresholds; therefore, DAQ limited the RACT analysis to emissions of NO_x. Appendix 3 contains the proposed RACT analysis from Caesars, which includes a complete list of emission units potentially subject to RACT requirements. These consist only of diesel-fired emergency generators and natural gas-fired boilers. DAQ followed Caesars's RACT analysis in grouping emission units with similar ratings or emissions concentrations in its own analysis.

Caesars reported 19.9 tpy actual NO_x emissions in 2017 for the National Emissions Inventory. Its RACT analysis generally aligns with this value, reporting actual emissions from 18.55 to 40.17

[71] Emission tests of the F100-PW-229 turbine jet engine during pre-flight verification of the F-16 aircraft, J. Merkisz, J. Markowski & J. Pielecha, Poznan University of Technology, Poland. WIT Transactions on Ecology and The Environment, Vol 174, 2013, p. 228. https://www.witpress.com/Secure/elibrary/papers/AIR13/AIR13019FU1.pdf

[72] Condition VI.B.3.a. "The permittee shall implement best management practices that result in compliance, at a minimum, with AQR 26, 40, and 43. *[AQR 12.5.2.6(a)]*" The Title V permit also contains emissions limits, fuel limits, testing requirements, and monitoring and reporting requirements.

tpy from 2019 to 2021.[73] Source-wide actual emissions are thus less than 70% of the stationary source's PTE. The Caesars RACT analysis also reports that actual emissions from emergency generators are between 1–6% of PTE, while each boiler's actual emissions are less than 50% of its PTE.

4.4.1 Boiler NO_x RACT

Caesars owns and operates five boilers (EUs: CP01–CP05) subject to NO_x RACT review. Each boiler is located at Caesars Palace and is approximately 34–35 MMBtu/hr in size. These boilers are classified as industrial, commercial, or institutional boilers because they include steam and hot water generators with heat input capacities from 0.4 to 1,500 MMBtu/hr.[74] According to the Caesars RACT analysis, the Hurst and Burnham boilers are 3-pass fire-tube, 800-bhp boilers; the existing Riello burners associated with all five boilers include LNB designs and cannot be modified to increase NO_x reduction to the level of ULNB capability. Caesars uses these boilers more than emergency generators or boilers at other Caesars properties, although they still are small emitters, with actual emissions of less than 3 tpy. All the boilers fire natural gas and have NO_x emissions limits of 29–30 ppm at 3% O_2. There are no limits on fuel use or operating hours.

4.4.1.1 Control Technology Analysis

Table 4.4-1 shows DAQ's RACT analyses for the Caesars boilers, based on information from the Caesars (and MGMRI) RACT analyses and other documents, as indicated.

Table 4.4-1. NO_x RACT Determinations for Caesars Boilers

CT #	Control Technology	RACT	Discussion
1	SCR	No	Caesars rejected SCR because the boiler exhaust gas temperatures are too low; flue-gas temperatures of a typical boiler range from 300–500°F, and Caesar reports exhaust temperatures of less than 400°F.[75] Figure 4-1 confirms the flue gas temperatures are too low for effective SCR operation. DAQ estimates a control effectiveness exceeding $18,000. DAQ concludes that this control technology is not RACT because it is neither cost-effective nor technically feasible for this type of boiler.
2	SNCR	No	Although having a lower capital and operating cost, SNCR is not available for this size industrial boiler because it operates best at temperatures of 1600–2000°F, but the boiler flue gas temperatures are less than 400°F (204°C)[76] (Figure 4-2). DAQ determines SNCR is not technically feasible for these boilers.
3	LNB	Yes	The boilers are equipped with LNB and required to operate at or below 30 ppm NO_x. DAQ finds that LNB qualifies as RACT.

[73] The first row of data in Caesars RACT Analysis Table 3 lists emissions for the "entire source", which appears to include all the emissions from all the different properties, no matter how small. The remaining rows of data list each emission unit with a NO_X PTE of 5 tpy or more and actual emissions for the 3 years 2019-2021. For 2019, for example, the total for all the 5+tpy units is 15.99 tpy versus 21.51 tpy for all the units (entire source).

[74] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 1-1.

[75] Technical advice on boiler combustion control, U.S. Department of Energy's Industrial Technologies Program, https://www.reliableplant.com/Read/22138/technical-advice-on-boiler-combustion-control

[76] Marek Pronobis, Environmentally Oriented Modernization of Power Boilers, 2020, Chapter 4.4.2.

CT #	Control Technology	RACT	Discussion
4	ULNB	No	This category includes metal mesh burners (as well as ceramic burners—see CT#15). For metal mesh burners or equivalent ULNB, DAQ calculated a CE of $9,015/ton to upgrade the burners to ULNB. This cost estimate is based on Caesars's cost figures using a 70% control efficiency for ULNB and adjusting Caesars's estimate for a 30-year life expectancy. DAQ finds that ULNB is not RACT because it is not cost-effective.[77]
5	GCP and GMP	Yes	These practices are the most common RACT determinations in the RBLC and are already being implemented on these units through the OP (Condition III.A.4.b). DAQ finds that GCP and GMP are RACT.
6	FGR	No	Caesars rejected FGR because of retrofit problems identified by its boiler maintenance contractor: the units cannot be retrofitted because of the configuration of the components for the combustion air supply for the burners.[78] Caesars indicates that the boilers already have LNB installed and some LNB include FGR to some extent as part of the design (even more so with ULNB).[79] Therefore, much of the NO_x reductions associated with FGR may already be realized by the LNB, which are keeping NO_x exhaust gas concentrations at 30 ppm or less. Although adding FGR to these boilers is likely not possible, DAQ calculated the CE to determine whether FGR was cost-effective. Several literature sources indicate a range of control efficiencies, in part due to different starting NO_x concentrations (e.g., from 260 to 110 ppm).[80] The Caesars boilers are already meeting NO_x limits of 30 ppm, so are already at a low concentration, but reductions of 40–50% using 20–30% FGR are possible.[81] Assuming a 50% emissions reduction and using a 1975 retrofit capital cost of $21,000,[82] adjusted for inflation using the CEPCI, DAQ estimated a CE of $6,182/ton NO_x removed. DAQ rejects FGR as RACT because the technology is technically infeasible to retrofit with the existing burners, and the control technology is not cost-effective.
7	LNB or ULNB + FGR	No	For Caesars, the cost of ULNB alone (see above) was not CE;

[77] ULNB can reduce NOx concentrations to 9 ppm from the current 29 to 30 ppm. Caesars's RACT analysis included a vendor quote showing a capital cost of around $235K; Caesars used a 10-year life without explanation, resulting in an annualized cost of about $32K. Because the amount of NOx reduction can be no more than 2.74 tpy (the actual emissions for the highest emitting boiler (CP02)), the cost effectiveness (CE) is high: $18,552. Using a 30-year life instead of 10, the capital recovery factor is reduced to 0.073 from 0.136, which reduces the annualized cost to $17,291, which still results in a high CE (e.g., for CP02, a removal of 1.918 tpy NOx results in a CE of $9015/ton and the CE for the other boilers would be higher). Caesars cited a number of CE determinations and thresholds for NOx, with the highest CE threshold being $5500/ton.

[78] From the Caesars RACT analysis: "According to the Caesars boiler maintenance contractor, the existing boilers with Riello burners cannot be retrofitted with FGR due to the configuration of the components for the combustion air supply for the burners. Therefore, an FGR retrofit is not technically feasible for these boilers. An FGR retrofit in conjunction with burner replacement is potentially feasible but since it would not represent a significant improvement in the amount of control possible when compared to retrofitting an ultra-low NOX burner alone, this control option is not considered to be an alternative control strategy to an ultralow NOX burner."

[79] APTI 418, Control of Nitrogen Oxides Emissions, Student Manual, 2000, p. 7-4.

[80] EPA-450/1-78-001, Control Techniques for Nitrogen Oxides Emissions from Stationary Source – Second Edition, January 1978, p. 3-25.

[81] APTI 418, Control of Nitrogen Oxides Emissions, Student Manual, 2000, p. 6-18.

[82] EPA-450/1-78-001, Control Techniques for Nitrogen Oxides Emissions from Stationary Source – Second Edition, January 1978, p. 4-55.

CT #	Control Technology	RACT	Discussion
			nonetheless, DAQ evaluated the CE of this technology using cost information provided by MGMRI. DAQ estimated a CE for ULNB/FR for Caesars's boilers at $21,960/ton. DAQ concludes that this control technology combination is not RACT because it is not cost-effective.
8	Excess Air Reduction (EAR) / Low Excess Air (LEA)	No	Boilers are generally run with 10–20% excess air (EA) to ensure full combustion (to minimize smoke, PM, and VOC, and for safety). Reducing EA is an "easy" approach[83] that can reduce NO_x emissions by 5-10%[84] or 16-20% (by going to 2-7% EA).[85] Often this is done by changing burners, so the cost and CE would be similar to that of installing a ULNB. Accordingly, DAQ concludes that this control technology is not RACT because it is not cost-effective.
9	Burner Out of Service (BOOS)	No	This is available only for multi-burner boilers; the Caesars boilers are single burner models (based on information from manufacturer websites.) With BOOS, one or more burners are taken out of service, meaning they do not burn fuel and instead are used to inject air or flue gas. It has a similar effect and cost to FGR or OFA. DAQ concludes that this control technology is not RACT because it is not available.
10	Overfire Air (OFA)	No	This is often used in conjunction with LNB, so may already be a part of the Caesars boilers. If not, OFA requires modifications to the boiler and is not available for some boiler configurations.[86] The emissions reductions available are estimated at 30–58%.[87] DAQ assumed 50% control efficiency and cost similar to FGR; the CE is $6,327/ton NO_x. DAQ has determined that this technology is not RACT because it is not available or cost-effective.
11	Air Register Adjustment (ARA)	No	Air registers control the distribution and control of high-volume combustion air. By adjusting the register door positioner, the air can be rotated in a clockwise or counter-clockwise direction. This rotating combustion air creates a thorough mixing of the fuel and air before it enters the combustion zone, resulting in complete, efficient combustion with low excess air. Single zone air registers are used on units up to ~120 MMBtu/hr, mainly in conjunction with overfire air, when the angle of the air flow can be adjusted. Since overfire air is not available or cost-effective, DAQ eliminated this control technology for further consideration in the RACT analysis.
12	Reduced Air Preheat (RAP)	No	Combustion air preheat is never used for fire-tube boiler configurations,[88] so there is no air preheat to reduce. When available, it can reduce NO_x emissions by 15–25%,[89] but is seldom used due to

83 APTI 418 Student Manual, p. 6-8.

84 http://cleanboiler.org/learn-about/boiler-efficiency-improvement/boiler-combustion/ However, this source also states that it is better to select a control technology that has little effect on excess air.

85 APTI 418 Student Manual, p. 6-9.

86 APTI 418, Control of Nitrogen Oxides Emissions, Student Manual, 2000, p. 6-10. "Overfire air combustion modifications require the penetration of the boiler wall by new air ducts and usually requires changes to the air handling system in order to deliver the air to the secondary combustion zone. Furthermore, there must be sufficient space above the burners and before the heat exchange area of the boiler to provide sufficient time for the combustion reactions. Because of this limitation, this approach is not possible on some existing coal-, oil-, and gas-fired suspension-type boilers."

87 APTI 418 Student Manual, p. 7-5. This is in conjunction with LNB, but yields reductions of 30-58% based on reducing emissions of 0.3 to 0.5 lb NO_X/MM Btu down to 0.21 lb/MM Btu. (e.g., (0.5-0.21)/0.5 = 0.58 or 58%)

88 EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 2-4.

89 APTI 418, Control of Nitrogen Oxides Emissions, Student Manual, 2000, p. 6-18 and 6-19.

CT #	Control Technology	RACT	Discussion
			efficiency penalties.[90] DAQ determined this control technology is not RACT because it is not available for these types of boilers.
13	Fuel conversion	No	This option is often addressed for several different pollutants, such as particulate matter and SO_x, when a fuel such as coal or oil is used. A fuel lower in nitrogen will produce less NO_x from nitrogen in the fuel.[91] The best fuel in terms of nitrogen content is natural gas, which the boilers already use, so switching is not an option. DAQ finds that fuel conversion is not RACT because it will not result in additional emissions reductions.
14	Water / Steam Injection (WSI)	No	One study is cited for package fire-tube boilers; for a 33.5 MMBtu/hr boiler and a capacity factor of 0.33, the CE in 1992 dollars is $3,903/ton NO_x removed.[92] This includes both oxygen trim and water/steam injection, and does not separate out the costs between the two because both are needed to get the reported NO_x reductions. Correcting that to 2022 costs using the CEPCI, CE_{2022} = $\$3,903_{1992}$ x ($\$824.5_{2022}$/$\$358.2_{1992}$) = $8,984/ton. DAQ concludes that water injection is not RACT because it is not cost-effective and has energy and safety disbenefits that outweigh the potential for NO_x emissions reductions.
15	CFB / Radiant Ceramic Burners (RCB)	No	This is a type of LNB. "The fiber burner is a burner using a ceramic fiber matrix as the combustion surface ~ Premixed gaseous fuel and air enter the burner plenum, pass through the fiber surface, and are ignited. Once the burner is operating steadily, the surface glows without visible flame at l,800°F and typical emissions are 20 ppm CO, 15 ppm NO_x, and 2 ppm HC."[93] NO_x emissions as low as 10 ppm have been reported; the burners can often be fitted into the same space as the original burners in fire-tube boilers, extending along the tube, and use the same auxiliary equipment as other burners, so the capital costs are relatively low. CFB have an additional advantage: thermal efficiency is increased by 1–2%, resulting in a savings of as much as 5% in natural gas. However, ceramic burners to date have been applied only in boilers of 16 MM Btu/hr or less, so are not feasible for the Caesars boilers, which are 30+ MM Btu/hr. Although ceramic burners are not technically feasible for the Caesars boilers, a CE analysis was conducted to provide information on how cost-effective the technology is. In a 2011 paper,[94] burner capital cost was estimated at $0.78/1000 Btu, so CFB for a 33 MMBtu/hr boiler would be $25,740 in 2011 dollars. Using the CEPCI, $Cost_{2022}$ = $25,740 x ($\$824.5_{2022}$/$\$585.7_{2011}$) = $36,235. Assuming the same direct/indirect costs of $3,000 that Caesars used for other cost analyses, a 10-year life for the burners (the ceramic is reportedly easily damaged), and a reduction of 50% (from 30 ppm to 15 ppm), the CE for CP02 with 2.74 tpy is $3,895/ton, which is cost-effective, but the CE for CP04 with 1.08 tpy is $9,881/ton,

[90] Oland, C. B., ORNL/TM-2002/19, GUIDE TO LOW-EMISSION BOILER AND COMBUSTION EQUIPMENT SELECTION, April 2002, Prepared for the U.S. Department of Energy, Office of Industrial Technologies, p. 5-5.

[91] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-4.

[92] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. D-3.

[93] RADIANT FIBER BURNERS FOR GAS-FIRED APPLIANCES AND EQUIPMENT, John P. Kesselring, Robert M. Kendall, and Richard J. Schreiber, Alzeta Corporation'

[94] Xu, T., CHARACTERIZING COSTS, SAVINGS AND BENEFITS OF A SELECTION OF ENERGY EFFICIENT EMERGING TECHNOLOGIES IN THE UNITED STATES, Lawrence Berkeley National Laboratory, 3/31/2011, https://escholarship.org/uc/item/3nb0863v.

CT #	Control Technology	RACT	Discussion
			which is not. However, a 5% fuel savings,[95] assuming the lowest hours of operation of 446.6 (CP01 in 2021) would be \$6,815/year, which would result in a CE of -\$1080 – -\$2,739)/year, depending on the unit. This CE, like most, is based on a number of assumptions, and the capital cost of other ULNB burners (based on vendor quotes) is considerably higher, so a more tailored analysis would be warranted to see if it would affect the RACT decision, including getting a quote from one of the manufacturers of these burners, such as the Alzeta Corporation.
16	Combined Combustion Modification (CCM)	No	This is a catch-all for different combinations of control techniques. The most demonstrated combination is LNB with FGR. Retrofit of combined LNB and FGR controls to existing packaged boilers is often more feasible than using FGR alone; also, combined retrofit of FGR and LNB to ICI boilers is considered by some to be a way of meeting stringent NO_x control regulations without using flue gas treatment controls. Data have been collected for 101 natural gas-fired units, 44 distillate oil-fired boilers, and 13 residual oil-fired boilers. All were watertube boilers, the majority located in California, so this information may not apply to Caesars fire-tube boilers. Many of the California boilers were existing units retrofitted with LNB/FGR controls. NO_x reduction efficiencies of 55 to 84% were reported for five units firing natural gas.[96] The most widely used combination is LNB with FGR, which DAQ already determined is not RACT because of a CE of \$21,960/ton (see CT #7 above).
17	Gas Fuel Flow Modifiers (GFFM)	No	A device known as a gas turbulator has been demonstrated to reduce NO_x formation in natural gas-fired packaged boilers. Originally designed to produce savings in fuel consumption, the turbulator is a small stainless-steel venturi incorporating strategically placed fins; the turbulator is inserted in the gas pipe directly upstream of the burner, creating highly turbulent fuel flow. This turbulence facilitates the bonding of hydrocarbon particles with the oxygen molecules of the combustion air, resulting in increased combustion efficiency. Fuel savings typically range from 2–10%, but have been as high as 35%. From the standpoint of NO_x emissions reductions, the more efficient turbulent mixing of fuel and air results in lower excess air requirements for efficient combustion, producing lower levels of NO_x. At one site, the use of a turbulator raised full-load boiler efficiency by 3% and the improved air-fuel mixing reduced the required excess oxygen by 27%. NO_x emissions were reduced from 58 to 35 ppm at 3% O_2, a 40% decrease.[97] The Caesars boilers are already equipped with LNB, which incorporate air-fuel mixing strategies, and are already emitting at only 30 ppm or less, so this technique likely will have little or no effect in reducing emissions. However, DAQ calculated CE using 15% reduction in NO_x and half the cost of installing ULNB. The CE was \$21,300, so DAQ concludes that GFFM is not cost-effective for RACT.
18	Forced Internal Recirculation (FIR) Burners	No	FIR burners use a combination of premixing, staging, and interstage heat removal to control NO_x and CO formation by (1) premixing sub-stoichiometric combustion air and significant internal recirculation of partial combustion products in the first stage to achieve stable, uniform combustion that minimizes peak flame temperature

[95] See https://www.eia.gov/dnav/ng/NG_PRI_SUM_DCU_SNV_M.htm for natural gas prices for Nevada.

[96] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-60.

[97] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-69.

CT #	Control Technology	RACT	Discussion
			and high oxygen pockets; (2) enhancing heat transfer from the first stage to reduce combustion temperatures in the second stage; and (3) controlling second-stage combustion to further minimize peak flame temperature. Burners based on this concept have no moving parts and avoid the need for external FGR.[98] These are classified as ULNB, since they can reach single digit NO_x concentrations (in ppm at 3% O_2). Assuming that the costs are the same as for generic ULNB burners (see CT #4 above), the CE would be $21,960/ton. DAQ finds that FIR is not RACT because it is not cost-effective.
19	Fuel-Induced Recirculation (FIR2)	No	FIR2 "involves the recirculation of a portion of the boiler flue gas and mixing it with the gas fuel at some point upstream of the burner. Although FIR has not yet been widely applied, it has been demonstrated commercially in an industrial unit in California, achieving NO_x emission readings as low as 17 ppm with little adverse effect on CO emissions."[99] Reductions of 48–68% have been demonstrated on a utility boiler;[100] cost information is difficult to find, but the Reese study indicated that capital costs are low. It is difficult to determine whether the existing units can be readily modified for FRI2, and whether the reductions LNB already achieved mean the reductions FRI2 can achieve would be lower. Assuming the cost is about the same as that of an FGR retrofit (estimated at $94,920) and the reduction achievable is 43% (assuming a reduction from 30 ppm down to 17 ppm), the CE is $6,038/ton. DAQ finds that FRI2 is not RACT because is not cost-effective.
20	Burner Tuning (BT)	No	See Oxygen Trim (#21). BT appears to be similar to OT in terms of operation and costs.
21	Oxygen Trim (OT)	No	OT and BT are two relatively simple operational modifications that can be performed to limit the amount of excess oxygen available for combustion. In certain cases, these adjustments can reduce NO_x emissions by as much as 15%, but the actual degree of NO_x reduction depends on the fuel characteristics and burning conditions. For LNBs equipped with automatic rather than manual OT, it is sometimes possible to achieve excess air levels of 5% or less without adversely affecting boiler performance.[101] An EPA publication mentions specific installations and 15–25% control.[102] These techniques, which are a form of LEA control, are often done in conjunction with other control techniques. Since the Caesars boilers are already equipped with LNB, which are designed for LEA, there may be little or no benefit trying to use OT or BT to reduce excess air further. There is little cost information, but one publication[103] mentions an OT retrofit costing $100 per MMBtu/hr in 1992 dollars. For a 33-MMBtu/hr burner, that is a $3,300 capital cost, which in 2022 dollars would be $3,300 x ($824.5$_{2022}$/358.2_{1992}$) = $7,596.

[98] Oland, C. B., ORNL/TM-2002/19, Guide to Low-Emission Boiler and Combustion Equipment Selection, p. 5-9. April 2002. Prepared for the U.S. Department of Energy, Office of Industrial Technologies.

[99] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-56.

[100] Reese, James L., et al., Demonstration of Fuel Injection Recirculation (FIR) for NO_X Emissions Control, 1994. https://collections.lib.utah.edu/ark:/87278/s6zg6vvv

[101] Oland, C. B., ORNL/TM-2002/19, Guide To Low-Emission Boiler And Combustion Equipment Selection, April 2002, Prepared for the U.S. Department of Energy, Office of Industrial Technologies, p. 5-5.

[102] EPA-453/R-94-022, Alternative Control Techniques Document—NO_x Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-64.

[103] EPA-453/R-94-022, Alternative Control Techniques Document—NO_x Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 2-17.

CT #	Control Technology	RACT	Discussion
			The report notes that the monitoring instrumentation (CEM) needed to ensure proper operation and safety could cost as much, so doubling the cost gives a capital cost of $15,192. Assuming $2,000 in annual maintenance, a 30-year life, and 15% reduction in emissions, CE = $7,552/ton. DAQ concludes that LEA is not RACT because it is not cost-effective.
21	Biased Firing (BF)	No	This is a process of biasing the fuel flow to different burners to create a lower peak temperature. Since the Caesars boilers have only one burner, this is not an applicable control technique.
22	Natural Gas Reburning (NGR)	No	This is a process of adding natural gas to combustion gases at a later stage of combustion. It has been demonstrated to be effective in reducing NO_x emissions from coal and oil burners by as much as 60%.[104] However, a literature search did not result in any articles or reports on use of NGR in natural gas-fired boilers (just coal-fired). DAQ concludes this technology is not technically feasible for gas-fired boilers.
23	Cyclonic Combustion Burner (CCB)	No	This is another type of LNB, so cost is addressed under LNB/ULNB above (CT #3 and 4). In cyclonic combustion, high tangential velocities are used in the burner to create a swirling flame pattern in the furnace. This causes intense internal mixing as well as recirculation of combustion gases, diluting the temperature of the near-stoichiometric flame and lowering thermal NO_x formation. The tangential flame causes close contact between combustion gases and the furnace wall, adding a convective component to the radiant heat transfer within the furnace. The increased heat transfer and low excess air operation of the cyclonic burner result in increased boiler efficiency.[105] To achieve ultra-low NO_x levels, a small quantity of low-pressure steam is injected into the burner, which further reduces the local flame temperature and NO_x formation. Testing revealed that NO_x emissions during natural gas firing could be reduced from 70 ppm to less than 20 ppm without affecting burner stability, low excess air operation, or turndown performance. However, the use of steam did result in a boiler heat efficiency loss of roughly 5%. The cyclonic burner is available as a stand-alone retrofit burner with a bolt-on feature, but no retrofit emissions data were found in an online search. Since achieving 20 ppm requires steam injection at the cost of efficiency, while other ULNB can achieve 9–10 ppm without using steam injection, DAQ finds that CCB is not RACT because it is not cost-effective and also has a collateral energy disbenefit.

Caesars reviewed the most recent five years of RACT determinations in the RBLC and found none, so considered the following potential control options for NO_x RACT for industrial boilers: FGR, ULNB, SCR, and SNCR. DAQ did not conduct a separate RBLC search, but expanded the Caesars search by using a full 10-year review of the RBLC conducted by another Clark County major source, MGMRI. In addition to SCR, MGMRI's search identified natural gas-fired boiler NO_x control technologies that included two combinations of controls: LNB with FGR and ULNB

[104] Oland, C. B., ORNL/TM-2002/19, GUIDE TO LOW-EMISSION BOILER AND COMBUSTION EQUIPMENT SELECTION, April 2002, Prepared for the U.S. Department of Energy, Office of Industrial Technologies, p. 5-7.

[105] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-54.

with FGR. DAQ identified additional control options in EPA's *Alternative Control Techniques (ACT) Document for NO_x Emissions from Industrial/Commercial/Institutional (ICI) Boilers*.[106]

Natural gas-fired boiler NO_x control techniques are divided into combustion and post-combustion controls. The LNB already installed on the Caesars boilers, which are in the first category, usually employ elements of more than one combustion control technique (e.g., the burner could be designed to reduce excess air (REA) or include FGR). For the Table 4.4-1 analyses, DAQ assumed the Caesars LNB design included combustion controls.

Staged Combustion Air (SCA) is an umbrella term covering several different techniques for injecting a portion of the total combustion air downstream of the fuel-rich primary combustion zone, including BOOS, Biased Firing (BF), adjusting burners lean and rich, OFA, and LNB and ULNB when the burner design incorporates staged combustion; up to a 50% reduction in NO_x emissions has been reported, depending on the technique used and the type and size of boiler.[107] Generally, LNB that incorporate SCA are used on small package boilers. Other than as a part of LNB and ULNB, SCA is not considered viable for existing fire-tube boilers because of the retrofit modifications required.[108]

The NO_x boiler control techniques identified and discussed in Table 4.4-1 have been identified in the literature. Some techniques, such as load reduction, reduced air preheat, and low excess air firing are not considered independent or viable control technologies. Fuel switching has traditionally not been viewed as a control technology. However, the switching from coal to oil or gas and from high-nitrogen residual oil to lighter oil fractions or gas have come under increased consideration in regional and seasonal NO_x compliance options."[109] Fuel switching refers to a change to a "cleaner" fuel; since the Caesars boilers already use natural gas, the cleanest of the fossil fuels, this option is not available even if it is considered a control technology.

Of the 23 boiler control technologies evaluated by DAQ, none appear to be both technically and economically feasible. CFB are not technically feasible (the boilers are too large for such burners), but if applicable, would appear to be economically feasible. CFB have the benefit of increasing efficiency and saving fuel. The CE for CP02 with 2.74 tpy actual emissions is \$3,895/ton, which is cost-effective, while the CE for CP04 with 1.08 tpy is \$9,881/ton, is not. However, a 5% fuel savings,[110] assuming the lowest hours of operation of 446.6 (CP01 in 2021) would be \$6,815/year, which would result in a CE of -\$1,080 to -\$2,739/year, depending on the unit. The reduction in actual emissions for equipping the two boilers with ceramic burners would have been 5.445 tpy.

[106] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-39.
[107] Oland, C. B., ORNL/TM-2002/19, Guide To Low-Emission Boiler And Combustion Equipment Selection, April 2002, Prepared for the U.S. Department of Energy, Office of Industrial Technologies, p. 5-7.
[108] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-57.
[109] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-40.
[110] See https://www.eia.gov/dnav/ng/NG_PRI_SUM_DCU_SNV_M.htm for natural gas prices for Nevada.

Metal mesh burners, like ceramic burners, are ultra-low NO_x burners (ULNB) and can reduce emissions substantially—in this case, down to 9 to 15 ppm. The metal mesh burners, in contrast to ceramic burners, are suitable for larger boilers up to over 100 MM Btu/hr, but the cost is much higher (an estimated $250,000, since metal mesh burners are custom-designed and built for each boiler make and model) and there are no fuel savings, so the metal mesh burner technology is not considered cost effective for these boilers.

Therefore, DAQ finds that ceramic fiber burners are not available for these emissions units and that metal mesh burners are not cost effective, so concludes that the existing controls constitute RACT for these boilers.

4.4.1.2 RACT Emissions Limitation

DAQ finds that RACT is LNB in combination with GCP for CP01 through CP05. DAQ proposes the following emissions limitation and monitoring, recordkeeping, and reporting requirements for these emission units based on RACT.

Table 4.4-2. Proposed RACT-Based NO_X Emission Limitations

Emission unit	NO_X RACT-based Emission Limitation
CP01, CP02	29 ppm corrected to 3% O_2 Operate and maintain boiler in accordance with manufacturer’s O&M.
CP03, CP04, CP05	30 ppm corrected to 3% O_2 Operate and maintain boiler in accordance with manufacturer’s O&M.

4.4.2 Emergency Generators

Caesars properties host 27 emergency generators subject to RACT review. The diesel generators are rated from 600 to 2,100 kW, and are limited to 100 hours of operation per year for testing and maintenance and up to 50 hours per year for nonemergency situations (which count toward the 100 hours). All the engines are turbocharged and aftercooled. In conducting its proposed RACT analysis, Caesars grouped the generators by power rating (hp) since those ratings largely determine the type and size of control device possible.

Caesars researched the most recent five years of RACT determinations in the RBLC and found none for similar generators. It also identified only SCR as an available control technology after consultation with its service contractor. DAQ considered this information and evaluated additional potentially available control technology options identified by other major sources and in the literature.

Table 4.4-3 contains DAQ’s RACT conclusions for the Caesars emergency generators, based on information from the Caesars RACT analyses and other information in Section 2.1 or discussed in DAQ’s conclusions. Unless otherwise noted, DAQ used a 30-year life, rather than the 10-year equipment life Caesars used, and 6% interest.

Table 4.4-3. NO_X RACT Analyses for Caesars Emergency Generators

CT #	Control Technology	RACT	Discussion
1	SCR	No	Even with a 30-year life, the CE is far above any threshold cited by the analysis (e.g., the $34,427/ton CE that Caesars calculated would only drop to $22,090/ton using a 30-year capital recovery factor). DAQ concludes that SCR is not RACT because it is not cost-effective.
2	SNCR	No	SNCR is not available for diesel engines because SCR operates best at temperatures of 1,600-2,000°F, while diesel engine exhaust gas ranges from 800-1,200°F.[111] SNCR also needs a fuel-rich engine operation or the use of reducing agents, so its use is limited to rich-burn engines; CI diesel engines are generally lean-burning. In addition, the exhaust gas temperature makes SNCR unsuitable (Figure 4-2).[112] DAQ finds SNCR is not RACT for the emergency generators because the control technology is not technically feasible.
3	DLN and SLN	No	DAQ located no articles, documents, or websites indicating use of DLN or SLN on diesel engines. DAQ finds that DLN and SLN are not commercially available for application to these engines.
4	Turbocharging	*Yes*	The emission units are currently equipped with a turbocharger and aftercooler.[113] Since they are already equipped with a turbocharger and no additional cost is estimated to use this control technology, DAQ concludes that use of a turbocharger qualifies as RACT.
5	GCP and GMP	*Yes*	These practices are the most common RACT determinations in the RBLC and are already being implemented through the Title V OP.[114] DAQ finds GCP and GMP qualify as RACT because they are cost-effective.
6	Pre-stratified charge	No	EPA documents indicate this technique is for spark ignition engines, not CI engines.[115] DAQ finds this control technology is technically infeasible for these CI-engine emergency generators.
7	EGR	No	DAQ makes no finding on the availability of this control technology, but agrees it does not quality as RACT because the potential energy and collateral pollutant disbenefits outweigh the benefit of NO_x emission reductions (Section 2.1.6).
8	ITR	No	If a unit is not already equipped for ITR, retrofit installation

[111] Marek Pronobis, *Environmentally Oriented Modernization of Power Boilers*, 2020, Chapter 4.4.2.

[112] Emission Factor Documentation, p. 2-18.

[113] The Title V permit requires:

> Condition III.E.4.p. The permittee shall operate each of the diesel engines with turbochargers and aftercoolers (EUs: CP13 through CP17, CP28, CP29, CP34, and CP35) (p. 44).

[114] From the Title V permit (Condition III.E.4. o. and q., p. 44):

> o. The permittee shall operate and maintain all diesel generators and fire pumps in accordance with the manufacturer's O&M manual for emissions-related components.
>
> q. The permittee shall ensure that the diesel engines are in compliance with 40 CFR Part 60, Subpart IIII, by meeting of all of the following (EUs: CP28, CP29, CP34, and CP35): *[40 CFR Part 60.4206]*
>
> > i. operation of the engine according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer; and
> >
> > ii. installation and configuration of the engine according to the manufacturer's specifications.

[115] EPA-453/R-93-032, Alternative Control Techniques Document-NO_X Emissions from Stationary Reciprocating Internal Combustion Engines, July 1993, p. 5-14.

CT #	Control Technology	RACT	Discussion
			results in a CE of $6,674/ton, higher than the $5,500/ton threshold.[116]
9	AFR Adjustments	No	DAQ makes no finding on the availability of this control technology, but finds it does not qualify as RACT because the energy and collateral pollutant disbenefits outweigh the benefits of the potential emissions reductions.
10	Derating / increasing speed	No	DAQ finds this control technology does not qualify as RACT because the energy and collateral pollutant disbenefits outweigh the potential for RACT emissions reductions.
11	Inlet MAT adjustment / aftercooler	Yes	Aftercooler already required, so DAQ considers it RACT.
12	DWI	No	The CE estimated for this 1,220-hp engine was based on larger engines (6000+ hp), giving a NO_x reduction of up to 60% at $11,006/ton.[117] This is nearly double the $5,500/ton threshold, even though it assumes a higher control level than the EPA literature value of 25–35%. DAQ concludes that DWI is not RACT because it is not cost-effective.
13	Water/fuel emulsions	No	DAQ estimates cost-effectiveness is $12,459/ton, over twice the threshold. DAQ finds this control technology is not RACT because it is not cost-effective.
14	EPMS	No	DAQ finds this control technology does not qualify as RACT because the amount of additional NO_x emissions reductions from its use is likely negligible.
15	High-pressure fuel injection	No	DAQ concludes this control technology does not qualify as RACT because its effect on reducing NO_x emissions and the ability to retrofit the technology for existing emission units is highly uncertain.
16	Conversion to natural gas (from diesel)	No	See #17—the numbers would be about the same.
17	Conversion to dual fuel (diesel/natural gas)	No	Some companies specialize in converting to dual fuels (e.g., https://engeniousengineering.com/ and https://dwppon.com /wp-ontent/uploads/2020/06/bifuel_compressed.pdf). Costs would include converting the generator to dual fuel (or to natural gas only, see #16) and the piping needed to supply the unit with natural gas; if natural gas is already available at the properties, the piping cost would be relatively low. Conversion cost for small diesels with turbochargers ranges from $8,000 to $12,000,[118] but because this is for small engines (truck/car), DAQ doubled the assumed cost to $24,000. Reductions of 20–-30% NO_x are expected.[119] EPA documents indicate the same range of control, with an estimated 26.5% reduction in NO_x between diesel and dual fuel engines.[120] CE = $17,739/ton, so DAQ found this technology is not cost-effective and rejected it as RACT.

[116] Based on data from EPA's ACT for NO_X emissions from ICE engines, p. 2-42, Table 2-14.

[117] Issa, M., Ibrahim, H., Ilinca, A. and Hayyani, M.Y. (2019) A Review and Economic Analysis of Different Emission Reduction Techniques for Marine Diesel Engines. Open Journal of Marine Science, 9, 148-171. https://doi.org/10.4236/ojms.2019.93012

[118] https://finddiffer.com/how-much-does-it-cost-to-convert-a-diesel-engine-to-gas/

[119] Talus Park, Dual fuel conversion of a direct-injection diesel engine, West Virginia University Master's Thesis, 1999.

[120] EPA-453/R-93-032, Alternative Control Techniques Document-NO_X Emissions from Stationary Reciprocating Internal Combustion Engines, July 1993, p. 2-3.

CT #	Control Technology	RACT	Discussion
18	Alternative fuels (other than natural gas)	No	The literature indicates that other fuels are not available for these engines. Methanol and LNG are the main alternatives besides emulsions. Methanol has serious corrosive and toxic problems, is costly, and can be readily contaminated with water, even if NO_x reductions can reach 60%. LNG requires huge investments for storage and installation and has high CO emissions.[121] DAQ finds that alternative fuels are not RACT for these emergency generators because the costs and potential collateral pollutant disbenefits outweigh the benefits of potential emissions reductions.

Overall, DAQ's RACT determination is that the existing controls (turbocharging, GCP/GMP, and aftercooler) constitute RACT for these emergency diesel generators.

4.5 SWITCH, WEST CAMPUS

Switch (Source ID:16304) owns and operates six separate and adjacent advanced technology ecosystem communications facilities at the following addresses: 7135 S Decatur, Las Vegas, NV 89118; 5225 Capovilla Las Vegas, NV 89118; 7365 Lindell Rd, Las Vegas, NV 89139; 7370 Jones Blvd, Las Vegas, NV 89139; 7380 S Lindell Rd, Las Vegas, NV 89139; and 5325 Capovilla, Las Vegas, NV 89118. The source is categorized under SIC code 7375, "Information Retrieval Services," and NAICS code 517919, "All Other Telecommunications."[122] Information on the emission units is available in the latest Switch OP and Technical Support Document (TSD), available on the Clark County website.

Switch has a facility-wide PTE NO_x of 246.18 tpy and reported only 33.23 tpy of actual NO_x emissions in 2017. The emission units include various size diesel generators for emergencies (mainly NO_x emissions), fire pumps, and cooling towers. The four fire pumps emit less than 0.2 tpy each, and the cooling towers have no NO_x or VOC emissions; therefore, the only emissions units this RACT analysis addressed were the 117 diesel-fired emergency generators (each approximately 3,353 hp/2,500 kW). The generators are limited to operating no more than 104 hours per year, so their individual unit PTE is only 2.06 tpy.[123] The fire pumps are limited to 500 hours of annual use. The cooling towers have no restrictions on use, but have no VOC and NO_x emissions.

Though all emission units were below the 5 tpy applicability threshold, DAQ requested that Switch conduct a RACT analysis that covered at least a majority of potential emissions. After a search of the RBLC, and considering information found in other state regulations, Switch identified EPA Tier 2 Certification,[124] GCP, and operating restrictions as available control technology options. Appendix 4 contains Switch's proposed NO_x RACT analysis.

[121] Issa, M., Ibrahim, H., Ilinca, A. and Hayyani, M.Y. (2019) A Review and Economic Analysis of Different Emission Reduction Techniques for Marine Diesel Engines. Open Journal of Marine Science, 9, 148-171. https://doi.org/10.4236/ojms.2019.93012
[122] Switch Part 70 Permit and Switch Technical Support Document (TSD)
[123] Switch Part 70 Permit, issued 7/1/21, p. 21.
[124] PART 70 TECHNICAL SUPPORT DOCUMENT (STATEMENT of BASIS) APPLICATION FOR: Renewal of Part 70 Operating Permit, July 1, 2021, p. 23.

4.5.1 Control Technology Analysis

The EPA Tier 2 certification refers to 40 CFR Part 60, Subpart IIII (New Source Performance Standards (NSPS)) standards for reciprocating internal combustion engines (RICE). For Units A02-A12, NO_x emissions are limited to no more than 9.0 g/kW-hr;[125] for the remainder of the units, the limit is 6.4 g/kW-hr of non-methane hydrocarbon (NMHC) + NO_x.

In addition to the available control technologies Switch identified in its proposed RACT analysis, DAQ considered whether other control technologies identified by other major sources for emergency engines might be cost-effective for Switch. Because a control device has to be sized for the emission unit operating at full capacity, a cost that is reasonable for a unit operated 6,000–8,000 hours per year will often be unreasonable for a unit operating only 100–500 hours per year. Given the smaller size and actual emissions of Switch's emergency engines compared to others considered in this analysis, DAQ would not expect a control cost to be reasonable for Switch if we found it not to be cost-effective for another major source. For example, using capital costs from W.W. Williams (in the Caesars cost estimates) and annual costs from Caesars for similar-size engines, the cost-effectiveness for SCR at a Switch engine—using the highest engine actual emissions, 1.16 tons of NO_x in 2017—is $21,125/ton NO_x, more than three times the RACT cost-effective threshold of $5,500/ton. This is equivalent to the cost-effectiveness estimated for emergency generators at NAFB and other major sources, so DAQ expects the control costs for the Switch diesel generators would be similar to (or more costly than) the cost estimated for the other major sources. Accordingly, DAQ concludes that additional add-on controls are not RACT for Switch's emergency engines.

The Switch Title V OP requires turbochargers and aftercoolers on all emergency generators,[126] that the source follow the manufacturer's O&M guidance,[127] and that the 117 units comply with the emissions limitations in 40 CFR Part 60, Subpart IIII. DAQ concludes these requirements are RACT. Switch's OP includes compliance and monitoring requirements to ensure these conditions are met; DAQ concludes these conditions constitute adequate monitoring, reporting, and recordkeeping to ensure compliance with RACT requirements.

4.6 MGM RESORTS INTERNATIONAL, LAS VEGAS

4.6.1 Background

MGMRI (Source ID: 825) owns a group of hotels within HA 212. DAQ issued MGMRI a renewed OP on May 19, 2022, that includes requirements for the following hotels, hereby referred to as "MGMRI": MGM Grand, New York-New York, Park MGM, The Signature at MGM Grand, Mandalay Bay, The Four Seasons, Luxor, Excalibur, Bellagio, CityCenter, and T-Mobile Arena.

[125] Part 70 Technical Support Document for Renewal of Part 70 Operating Permit, July 1, 2021, Appendix 4A, p. 31.
[126] Switch OP, issued 7/1/21, Condition III.C.3.a.
[127] Switch OP, issued 7/1/21, Condition III.C.3.b.

MGMRI is currently a major source of NO_x with a stationary source-wide PTE of 757.05 tpy, but reported only 65.07 tpy of actual NO_x emissions in 2017. Its RACT analysis computed actual emissions from average annual fuel use over the most recent three years (2019–2021) to show that its average annual actual emissions are approximately 24% of its PTE.

MGMRI listed all its emission units potentially subject to RACT (those with a PTE of 5 tpy or more) in a table in Appendix B of its proposed RACT analysis (Appendix 5).[128] These include two natural gas-fired boilers and 46 diesel-fired engines driving emergency generators.

The process equipment consists of two natural gas-fired boilers, each with a capacity of 32.66 MMBtu/hr, and 46 diesel-fired emergency generators that range from 1,100–3,700 hp. The boilers are classified as Commercial/Institutional (< 100 MMBtu/hr) and the engines as Large Internal Combustion Engines (> 500 hp). The two Cleaver Brooks boilers (MG13 and 14), which are Model CBLE series, are permitted to use only natural gas. According to the manufacturer's website, the CBLE are high-efficiency fire-tube boilers that can be ordered to achieve less than 60, 30, 9, or 5 ppm NO_x.[129] The permitted limit of 40 ppm at 3% O_2 is higher than the more common 30 ppm limit for LNB boilers.

Appendix 5 contains MGMRI's proposed RACT analysis. MGMRI indicated that it identified available control technologies via the RBLC, surveying agencies, engineering experience, vendor surveys, and surveys of available literature. The RBLC search was conducted for the most recent 10 years.

4.6.1.1 Boiler RACT

MGMRI identified the following as potentially available control technologies for natural gas-fired boilers:

- GCP use;
- LNB and FGR;
- ULNB and FGR; and
- SCR.

[128] While reviewing MGMRI's list of emission units, DAQ notes that although Table B lists the proper number of emission units, it is both difficult to read and appears to contain errors in labeling. Specifically, on page B-1, the right column skips from BE83 to BE85; BE85 should have been listed as BE84 (because that's the BE84 serial number in the description), BE86 should be labeled BE85, BE87 should be BE86, BE88 should be BE87, and (on page B-2, right column), CC009 should be BE88. Continuing on page B-2, CC010 should be CC009, CC011 should be CC010, etc., ending with CC015, which should be CC014. Finally, TM01 should be labeled CC015 and the first TBB15 (serial number DD501118) should be labeled TM01. Note, however, that the table does contain all the emission units that meet the criteria for a RACT analysis.

[129] MGMRI's OP limits the two boilers to 40 ppm NOx at 3% O2: "The permittee shall operate and maintain each of the boilers with burners that have a manufacturer's maximum emission concentration of 40 ppmv NOx, corrected to 3% oxygen (EUs: MG01, MG02, MG05, MG06, MG13, MG14, and MG16)." Condition III.A.5.c.

EPA has indicated[130] in a NO_x ACT document that the following are also potential combustion modification control technologies:

- Water /Steam Injection; [131]
- SCA (the most common LNB);
- CFB;
- CCM; and
- GFFM.

DAQ used MGMRI analyses for these control technologies and considered additional technologies not on either list (Table 4.6-1).

Table 4.6-1. NO_x RACT Determinations for MGMRI Boilers

CT #	Control Technology	RACT	Discussion
1	SCR	No	MGMRI rejected SCR because the boiler exhaust gas temperatures are too low; MGMRI did not document an actual flue temperature, but the flue-gas temperature of a typical boiler ranges between 300–500°F.[132] Figure 4-1 confirms that such flue gas temperatures are too low for effective SCR, so it is not technically feasible. Even if SCR could be applied, the Lansing SCR analysis for a larger boiler had a high cost-effectiveness value and DAQ expects costs for MGMRI would be similar. DAQ finds SCR is not RACT for these boilers because the control technology is not technically feasible or cost-effective.
2	SNCR	No	SNCR is not available for this size industrial boiler because it operates best at temperatures of 1,600-2,000°F, but the boiler flue gas temperature is only around 400°F (204°C)[133] (Figure 4-2). Therefore, SNCR is unsuitable RACT for these boilers.
3	LNB / ULNB	Yes	The boilers are already equipped with burners, presumably LNB, that allow them to meet a limit of 40 ppm NO_x at 3% O_2.[134] The literature appears to classify LNB as burners able to reduce NO_x concentrations from over 100 ppm to around 30 ppm (the most common).
	ULNB	No	The boilers are already equipped with LNB.[135] MGMRI's RACT

[130] EPA-453/R-94-022, Alternative Control Techniques Document—NOx Emissions from Industrial/ Commercial/Institutional (lCI) Boilers, March 1994.

[131] For example, the ACT document states that WI "has seen very limited application in Southern California, where NOx emission regulations are the most stringent. Because of low initial cost, the technique is considered particularly effective for small single-burner packaged boilers operated infrequently."

[132] Technical advice on boiler combustion control, U.S. Department of Energy's Industrial Technologies Program, https://www.reliableplant.com/Read/22138/technical-advice-on-boiler-combustion-control

[133] Marek Pronobis, *Environmentally Oriented Modernization of Power Boilers*, Chapter 4.4.2. 2020.

[134] Condition III.A.5.c.: "The permittee shall operate and maintain each of the boilers with burners that have a manufacturer's maximum emission concentration of 40 ppmv NOx, corrected to 3% oxygen (EUs: MG01, MG02, MG05, MG06, MG13, MG14, and MG16). [Title V OP (10/21/13)]"

[135] Condition III.A.5.c.: "The permittee shall operate and maintain each of the boilers with burners that have a manufacturer's maximum emission concentration of 40 ppmv NOx, corrected to 3% oxygen (EUs: MG01, MG02, MG05, MG06, MG13, MG14, and MG16). [Title V OP (10/21/13)]"

CT #	Control Technology	RACT	Discussion
			analysis did not consider upgrading the burners to ULNB control technology. However, DAQ analyzed the use of metal mesh ULNB, which can be used on boilers up to 100 MM Btu/hr or more. DAQ used a relatively low capital cost estimate (dated 9/13/22) of $235K from Pyro Combustion (Appendix 3, Caesars), a 77% control efficiency for ULNB alone, and a conservative 30-year (instead of 10) life; the CE was $13,357/ton of NO_x removed. DAQ finds that ULNB is not RACT because it is not cost-effective.
4	GCP and GMP	Yes	These practices are the most common RACT determinations in the RBLC and are already being implemented on these units through the Title V OP (Condition III.A.5.b).[136] DAQ finds this control technology is RACT.
5	FGR	No	The MGMRI RACT analysis (Appendix 5, Table 2-1) states that adding FGR to the existing LNB would reduce emissions by 35.69%, with a capital investment of $77,200, an annual equipment cost of $13,587.20, and total annual operating cost of $39,520.61; the computed CE was $89,868. However, the operating cost was based on 8,760 hours per year, while the emissions reduction was based on actual emissions, which were equivalent to only 1.66/6.95 tpy = 0.239 (~24%), so the actual operating expenses would be $39,520 x 0.239 = $9,439/year. Using this value and a 30-year life, CE = $25,399/ton; even when the operating cost is left out completely, CE = $9,467, still higher than the $5,500 RACT threshold. There are some uncertainties about MGMRI capital costs, which are based on 1/3 of the cost for an installation that included an SCR, so DAQ conducted a separate cost estimate. A 1975 retrofit capital cost of $21,000[137] was adjusted for inflation using the CEPCI to obtain a CE of $6,182/ton NO_x removed, which is lower than the MGMRI and adjusted MGMRI values but still above the CE threshold of $5,500/ton. DAQ determines FGR is not RACT because it is not cost-effective.
6	LNB + FGR or ULNB + FGR	No	The first option, LNB+FGR, is addressed in the FGR determination (#5). The ULNB+FGR option was included in the MGMRI RACT analysis for its boilers, with a 75% reduction from current actual emissions of 1.66 tpy, $126,200 capital cost, $22,211 direct and indirect (equipment) costs, $39,520 annual operating costs (at 8,760 hr/yr), and 10-year life, so CE = $49,707. This is above the $5,500 threshold, but has too high an operating cost (see #5), which should be reduced to 23.9% based on actual hours of operation. In addition, the 10-year life assumed by MGMRI was not documented. Using the adjusted operating cost of $39,520 x 0.239 = $9,445 and a 30-year life, CE = $13,382, above the RACT CE threshold of $5,500. Based on the EPA cost manual, MGMRI calculated the annual equipment costs at $22,211 (Att. 5, Table 2-2, footnote 3). DAQ finds this control technology is not cost-effective.
7	EAR / LEA	No	Boilers are generally run with 10–20% EA to ensure full combustion (to minimize smoke, PM, and VOC, and for safety). Reducing EA is an "easy" approach[138] that can reduce NO_x emissions by 5–

[136] "The permittee shall operate and maintain each boiler and heater in accordance with the manufacturer's operations and maintenance (O&M) manual for emissions-related components and good combustion practices."
[137] EPA-450/1-78-001, Control Techniques for Nitrogen Oxides Emissions from Stationary Source – Second Edition, January 1978, p. 4-55.
[138] APTI 418 Student Manual, p. 6-8.

CT #	Control Technology	RACT	Discussion
			10%[139] or 16–20% (by going to 2–7% EA).[140] Often this is done by changing burners, so the cost would be similar to that of installing a ULNB. DAQ finds this control technology is not RACT because it is not cost-effective.
8	BOOS	No	This approach is available only for multi-burner boilers; from the manufacturer's website, the MGMRI boilers appear to be single-burner models. With BOOS, one or more burners are taken out of service, meaning they don't burn fuel but instead are used to inject air or flue gas. They have a similar effect and cost as FGR or OFA. DAQ finds this control technology is not RACT because it is not available for this type of boiler and, even if it were, it would not be cost-effective.
9	OFA	No	This is often used in conjunction with LNB, so may already be a part of the MGMRI boilers. If not, OFA requires modifications to the boiler and is not available for some boiler configurations.[141] The reduction available is estimated at 30–50%; using 50% and costs similar to FGR, CE = $6,327/ton NO_x. DAQ finds this control technology is not RACT because it is not cost-effective.
10	ARA	No	Air registers control the distribution and control of high-volume combustion air. By adjusting the register door positioner, the air can be rotated either in a clockwise or counter-clockwise direction. This rotating combustion air creates a thorough mixing of the fuel and air before it enters the combustion zone, resulting in complete, efficient combustion with low excess air. Single zone air registers are used on units up to ~120 MMBtu/Hr. This technique is mainly done where there is overfire air and the angle of the air flow can be adjusted. Overfire air generally is not used in fire-tube boilers, so is not considered available.[142] DAQ finds this is not RACT because the control is not available.
11	RAP	No	Combustion air preheat is not used for fire-tube boiler configurations,[143] so there is no air preheat to reduce. When available, it can reduce NO_x emissions by 15–25%,[144] but it is seldom used due to efficiency penalties.[145] DAQ finds this control technology is not RACT because the energy disbenefits outweigh the potential emissions reduction benefits.
12	Fuel conversion	No	This option is often addressed for several different pollutants, such as PM and SO_x, when a fuel such as coal or oil is used. A fuel

139 http://cleanboiler.org/learn-about/boiler-efficiency-improvement/boiler-combustion/ However, this source also states that it is better to select a control technology that has little effect on excess air.

140 APTI 418 Student Manual, p. 6-9.

141 APTI 418, Control of Nitrogen Oxides Emissions, Student Manual, 2000, p. 6-10. "Overfire air combustion modifications require the penetration of the boiler wall by new air ducts and usually requires changes to the air handling system in order to deliver the air to the secondary combustion zone. Furthermore, there must be sufficient space above the burners and before the heat exchange area of the boiler to provide sufficient time for the combustion reactions. Because of this limitation, this approach is not possible on some existing coal-, oil-, and gas-fired suspension-type boilers."

142 EPA-450/1-78-001, Control Techniques for Nitrogen Oxides Emissions from Stationary Source – Second Edition, January 1978, p. 4-50.

143 EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 2-4.

144 APTI 418, Control of Nitrogen Oxides Emissions, Student Manual, 2000, p. 6-18 and 6-19.

145 Oland, C. B., ORNL/TM-2002/19, Guide To Low-Emission Boiler And Combustion Equipment Selection**,** April 2002, Prepared for the U.S. Department of Energy, Office of Industrial Technologies, p. 5-5.

CT #	Control Technology	RACT	Discussion
			lower in nitrogen will produce less NO_x from nitrogen in the fuel.[146] The best fossil fuel in terms of nitrogen content is natural gas, which the boilers already use, so switching is not an option. DAQ finds this control technology is not RACT because another fuel would not generate NO_x emissions reductions.
13	WSI	No	A literature search produced no information on the technical feasibility of adding water or steam injection to boilers with LNB and on whether the amount of NO_x reduction would be less (since LNB already have reduced emissions), and very little cost information. In one study cited for package fire-tube boilers, for a 33.5 MMBtu/hr boiler and a capacity factor of 0.33, the CE in 1992 dollars is \$3,903/ton NO_x removed.[147] This includes both OT and WSI and does not separate out the costs between the two, since both are needed to get the reported NO_x reductions. Correcting that to 2022 costs using the CEPCI, CE_{2022} = $\$3903_{1992}$ x ($\$824.5_{2022}$ / $\$358.2_{1992}$) = \$8,984/ton. DAQ finds that WSI is not RACT because it is not cost-effective.
14	CFB / RCB	No	This is a type of LNB. "The fiber burner is a burner using a ceramic fiber matrix as the combustion surface ~ Premixed gaseous fuel and air enter the burner plenum, pass through the fiber surface, and are ignited. Once the burner is operating steadily, the surface glows without visible flame at l800°F and typical emissions are 20 ppm CO, 15 ppm NO_x, and 2 ppm HC."[148] NO_x emissions as low as 10 ppm have been reported; the burners can often be fitted into the same space as the original burners in fire-tube boilers, extending along the tube, and use the same auxiliary equipment as other burners, so the capital costs are relatively low. CFB have an additional advantage: thermal efficiency is increased by 1–2%, resulting in savings of up to 5% in natural gas. However, ceramic burners to date have been applied only in boilers of 16 MM Btu/hr or less, so are not feasible for the MGMRI boilers, which are 30+ MM Btu/hr. Although ceramic burners are not technically feasible for the MGMRI boilers, an analysis was conducted to provide information on how cost-effective the technology is. A 2011 paper[149] estimated burner capital cost at \$0.78/1000 Btu, so CFB for a 33 MMBtu/hour boiler would be \$25,740 in 2011 dollars. Using the CEPCI, $Cost_{2022}$ = \$25,740 x ($\$824.5_{2022}$/$\$585.7_{2011}$) = \$36,235. Assuming general direct/indirect costs of \$3,000 (used for other cost analyses), a 10-year life for the burners (the ceramic is reportedly easily damaged), and a reduction of 62.5% (from 40 ppm to 15 ppm), the CE for each boiler = \$5,143/ton, which is cost-effective. However, a 5% fuel savings,[150] assuming 2,094 hours of operation, would be a savings of \$31,959/year, which would yield a net annual cost of -\$26,623/year and a CE = -\$25,661/year. This CE, like most, is based on a number of assumptions, and the

[146] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-4.
[147] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. D-3.
[148] Radiant Fiber Burners For Gas-Fired Appliances And Equipment, John P. Kesselring, Robert M. Kendall, and Richard J. Schreiber, Alzeta Corporation'
[149] Xu, T., Characterizing Costs, Savings And Benefits Of A Selection Of Energy Efficient Emerging Technologies In The United States, Lawrence Berkeley National Laboratory, 3/31/2011, https://escholarship.org/uc/item/3nb0863v.
[150] See https://www.eia.gov/dnav/ng/NG_PRI_SUM_DCU_SNV_M.htm for natural gas prices for Nevada.

CT #	Control Technology	RACT	Discussion
			capital cost of other ULNB burners based on vendor quotes is considerably higher, so a more tailored analysis would be warranted to see if it would affect the RACT decision, including getting a quote from one of the burner manufacturers, such as the Alzeta Corporation.
15	CCM	No	This is a catch-all for different combinations of control techniques. The most demonstrated combination is the use of LNB with FGR. Retrofit of combined LNB and FGR controls to existing packaged boilers is often more feasible than using FGR alone. Also, combined retrofit of FGR and LNB to ICI boilers is considered by some to be a way of meeting stringent NO_x control regulations without using flue gas treatment controls. Data have been collected for 101 natural gas-fired units, 44 distillate oil-fired boilers, and 13 residual oil-fired boilers. All were watertube boilers, not the fire-tube boilers MGMRI has; most were in California. Many of the California boilers were existing units retrofitted with LNB/FGR controls. NO_x reduction efficiencies of 55–84% were reported for five units firing natural gas.[151] The most widely used combination, LNB with FGR, has a CE = $21,960/ton (see #6). DAQ finds this control technology is not RACT because it is not cost-effective.
16	GFFM	No	A device known as a gas turbulator has been demonstrated to reduce NO_x formation in natural gas-fired packaged boilers. Originally designed to produce savings in fuel consumption, the turbulator is a small stainless-steel venturi incorporating strategically placed fins. The turbulator is inserted in the gas pipe directly upstream of the burner, creating highly turbulent fuel flow. This turbulence facilitates the bonding of hydrocarbon particles with the oxygen molecules of the combustion air, resulting in increased combustion efficiency. Fuel savings typically range between 2–10%, but have been as high as 35%. From a NO_x standpoint, the more efficient turbulent mixing of fuel and air results in lower excess air requirements for efficient combustion, producing lower levels of NO_x. At one site, turbulator use raised full-load boiler efficiency by 3% and the improved air-fuel mixing reduced the required excess oxygen by 27%. NO_x emissions were reduced from 58 to 35 ppm at 3% O_2, a 40% decrease.[152] The MGMRI boilers are already equipped with LNB, which incorporate air-fuel mixing strategies, and are already emitting at only 40 ppm or less, so this technique likely will have little or no effect in reducing emissions. However, CE was calculated using a 15% reduction in NO_x and half the cost of installing ULNB. The CE was $21,300/ton. DAQ finds GFFM is not RACT because it is not cost-effective.
17	FIR Burners	No	FIR burners use a combination of premixing, staging, and interstage heat removal to control NO_x and CO formation by (1) premixing sub-stoichiometric combustion air and significant internal recirculation of partial combustion products in the first stage to achieve stable, uniform combustion that minimizes peak flame temperature and high oxygen pockets; (2) enhancing heat transfer from the first stage to reduce combustion temperatures in the second stage; and (3) controlling second-stage combustion to further minimize peak flame temperature. Burners based on this concept

[151] EPA-453/R-94-022, Alternative Control Techniques Document—NO_x Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-60.
[152] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-69.

CT #	Control Technology	RACT	Discussion
			have no moving parts and avoid the need for external FGR.[153] These are classified as ULNB, since they can reach single-digit NO_x concentrations (in ppm at 3% O_2). Assuming that the costs are the same as for generic ULNB burners (see #6), the CE = $21,960/ton. DAQ finds this control technology is not RACT because it is not cost-effective.
18	FRI2	No	FIR2 "involves the recirculation of a portion of the boiler flue gas and mixing it with the gas fuel at some point upstream of the burner. Although FIR has not yet been widely applied, it has been demonstrated commercially in an industrial unit in California, achieving NO_x emission readings as low as 17 ppm with little adverse effect on CO emissions."[154] Reductions of 48–68% have been demonstrated on a utility boiler;[155] cost information is difficult to find, but the Reese study indicated that capital costs are low. It is difficult to determine whether the existing units can be readily modified for FRI2 and whether the reductions already achieved by the LNB mean that the reductions that can be achieved by FRI2 would be lower. Assuming that the cost is about the same as that of an FGR retrofit (estimated at $94,920) and that the reduction achievable is 57% (assuming a reduction from 40 ppm down to 17 ppm), CE = $7,518/ton. DAQ finds this control technology is not RACT because it is not cost-effective.
19	BT	No	See OT (#20). BT appears to be similar to OT in terms of operation and costs.
20	OT	No	OT and BT are two relatively simple operational modifications that can be performed to limit the amount of excess oxygen available for combustion. In certain cases, these adjustments can reduce NO_x emissions by as much as 15%, but the actual degree of NO_x reduction depends on the fuel characteristics and burning conditions. For LNBs equipped with automatic rather than manual OT, it is sometimes possible to achieve excess air levels of 5% or less without adversely affecting boiler performance.[156] An EPA publication mentions specific installations and 15–25% control.[157] These techniques, which are a form of LEA control, are often done in conjunction with other control techniques. Since the MGMRI boilers are already equipped with LNB, which generally are designed for LEA, there may be little or no benefit in trying to use OT or BT to reduce excess air further. There is little cost information, but one publication[158] mentions an OT retrofit costing $100 per MMBtu/hr in 1992 dollars. For a 33 MMBtu/hr burner, that is a $3,300 capital cost; in 2022 dollars, this is $3,300 x ($824.5$_{2022}$/358.2_{1992}$) = $7,596. The report notes that the monitoring instrumentation (CEM) needed to ensure proper operation and safety could cost as

153 Oland, C. B., ORNL/TM-2002/19, Guide To Low-Emission Boiler And Combustion Equipment Selection, April 2002, Prepared for the U.S. Department of Energy, Office of Industrial Technologies, p. 5-9.
154 EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-56.
155 Reese, James L., et al., Demonstration of Fuel Injection Recirculation (FIR) for NO_X Emissions Control, 1994. https://collections.lib.utah.edu/ark:/87278/s6zg6vvv
156 "Guide to Low-Emission Boiler and Combustion Equipment Selection," p. 5-5. Oland, C.B. ORNL/TM-2002/19, April 2002.
157 Alternative Control Techniques Document—NO_x Emissions from Industrial/Commercial/Institutional (lCI) Boilers, p. 5-64. EPA-453/R-94-022, March 1994.
158 EPA-453/R-94-022, Alternative Control Techniques Document—NO_x Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 2-17.

CT #	Control Technology	RACT	Discussion
			much, so doubling the cost gives a capital cost of $15,192. Assuming $2,000 in annual maintenance, a 30-year life, and a 15% reduction in emissions, CE = $7,552/ton. DAQ finds this control technology is not RACT because it is not cost-effective.
21	BF	No	This is a process of biasing the fuel flow to different burners to create a lower peak temperature. Since the MGMRI boilers have only one burner, it is not an applicable control technique. DAQ finds this control technology is not RACT because it is not technically feasible.
22	NGR	No	This is a process of adding natural gas to combustion gases at a later stage of combustion. It has been demonstrated to be effective in reducing NO_x emissions from coal and oil burners by as much as 60%.[159] However, a literature search did not result in any articles or reports on use of NGR in natural gas-fired boilers (just coal- and oil-fired), so this technology is considered not technically feasible for gas-fired boilers. DAQ finds this control technology is not RACT because it is not technically feasible.
23	CCB	No	This is another type of LNB, so cost is addressed under LNB/ULNB (#6). In cyclonic combustion, high tangential velocities are used in the burner to create a swirling flame pattern in the furnace. This causes intense internal mixing as well as recirculation of combustion gases, diluting the temperature of the near-stoichiometric flame and lowering thermal NO_x formation. The tangential flame causes close contact between combustion gases and the furnace wall, adding a convective component to the radiant heat transfer within the furnace. The increased heat transfer and low excess air operation of the cyclonic burner result in increased boiler efficiency.[160] To achieve ultra-low NO_x levels, a small quantity of low-pressure steam is injected into the burner, which further reduces the local flame temperature and NO_x formation. Testing revealed that NO_x emissions during natural gas firing could be reduced from 70 ppm to less than 20 ppm without affecting burner stability, low excess air operation, or turndown performance. However, the use of steam did result in a boiler heat efficiency loss of roughly 5%. The cyclonic burner is available as a stand-alone retrofit burner with a bolt-on feature; however, no retrofit emissions data were obtained. Since achieving 20 ppm requires steam injection at the cost of efficiency and other ULNB can achieve 9–10 ppm without using steam injection, and assuming the cost of CCB is similar to other ULNB, DAQ finds this control technology is not RACT because it is not cost-effective.

Of the 23 boiler control technologies evaluated by DAQ, none appear to be both technically and economically feasible. CFB are not technically feasible (the boilers are too large for such burners), but if applicable, would appear to be economically feasible.[161] DAQ concludes that the existing controls and monitoring constitute RACT for the boilers.

[159] "Guide to Low-Emission Boiler and Combustion Equipment Selection," p. 5-7. Oland, C.B. ORNL/TM-2002/19, April 2002.

[160] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-54.

[161] This technique has the benefit of increasing efficiency and saving fuel, so may actually be more cost-effective than preliminary analysis indicates: the CE without considering fuel savings is $5,143/ton, below the $5,500/ton threshold, while considering fuel savings results in a CE = -$25,661/ton (a cost savings). The reduction in actual emissions from equipping the two boilers with ceramic burners would be 2.08 tpy.

4.6.1.2 Emergency Generators

The other RACT analysis was conducted on the 46 emergency generators on various MGMRI properties that met the criteria for review. The diesel generators are rated from 1,180 to 3,701 hp and are all from the same manufacturer. The PTE for the generators ranges from 7.08 to 15.12 tpy. For all 46 units, the Title V OP limits operation to 500 hours per year per generator, including emergency use; only 100 hours per year of this 500 hours can be for nonemergency purposes, and only 50 of the 100 hours can be for nonemergency purposes other than testing and monitoring.[162] All 46 units are required to follow the manufacturer's O&M guidance, which is generally accepted as constituting GCP.[163] In addition, the OP requires all the units to have turbochargers and aftercoolers except:

- Turbochargers only: EX007-EX010 and NY27-NY29.
- Neither: TM01.

Compressing the air and/or exhaust gas that goes to the inlet heats up the gas, which would raise the maximum temperature in the cylinders unless it is cooled back down with an aftercooler. Therefore, adding an aftercooler to the units that require only turbochargers should reduce NO_x emissions.

TM01 is the only unit where neither turbocharging nor aftercoolers are required by the Title V OP, but it is also the only unit specifically mentioned as subject to EPA's Tier Certification. More information is needed to determine the design and configuration of TM01, but it likely has some form of control built into the design because despite being the largest engine, its PTE at 500 hours is only 10.83 tpy NO_x compared to a higher (up to 15.12 tpy) PTE for smaller engines at the MGMRI properties.

MGMRI did not provide actual emissions information in its RACT analysis, so DAQ used data from five emergency generators at NAFB to estimate actual emissions from the MGMRI units. This was done by comparing the maximum actual NO_x emissions at each unit from 2017–2021 to the units' PTE. Unit 41 at NAFB had maximum actual emissions of 1.861 tpy compared to a PTE of 8.07 tpy, so actual emissions were 23.1% of the PTE. Taking the highest MGMRI unit PTE (15.12 tpy) times 0.231 yields an estimated maximum actual 3.49 tpy. This value was used for the CE calculations.

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[162] For example, Condition III.A.4.a.: "The permittee shall limit the operation of the emergency generators and fire pumps (EUs: MG17 through MG24, MG26 through MG28, MG51, and MG113) for testing and maintenance purposes to 100 hours per calendar year. The permittee may operate the emergency engines up to 50 hours per calendar year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per calendar year for nonemergency situations cannot be used for peak shavings or to generate income for the facility." These hourly limits are what distinguish an emergency generator from other generators, per 40 CFR 60.4211.

[163] For example, Condition III.A.5.p.: "The permittee shall operate and maintain all diesel generators and fire pumps in accordance with the manufacturer's O&M manual for emissions-related components (EUs: MG17 through MG24, MG26 through MG28, MG51, and MG113)."

4.6.1.3 MGMRI RACT Analysis

The only technically feasible options listed by MGMRI for the generators were (1) EPA Tier Certification, where the engine, based on the date of manufacture and construction, is certified to comply with EPA Tier Emission Standards per 40 CFR Part 60, Subpart IIII; and (2) GCP. One MGMRI unit (TM01, the largest, at Treasure Island) is certified; all the units were assumed to practice GCP, which was considered equivalent to the requirement in the Title V OP for all the MGMRI units to adhere to the manufacturers' O&M guidance. MGMRI also considered any add-on controls, like SCR, to be not technically feasible based on the lack of any RACT determinations in the RBLC and on an EPA statement regarding use of SCR and other add-on controls for emergency generators. MGMRI did not address other control options, such as those in documents like EPA's 1978 ACT[164] for NO_x emissions.

4.6.1.4 DAQ RACT Analysis

DAQ has reviewed the MGMRI RACT analyses (Appendix 5), revised them as necessary, and conducted RACT analyses for control technologies not included in the MGMRI analysis. The analyses are summarized in Table 4.6-2; the actual CE calculations are in Appendix 9.

The emergency generators currently:

- Are all required to practice GCP and GMP; and
- Have and use turbochargers and aftercoolers except for the eight units (EX007–010 and NY 27–29, plus TM01) that are not required to have aftercoolers.
- For TM01, which is Tier Certified, meet the appropriate limit in 40 CFR Part 60, Subpart IIII.

DAQ has determined that the current control techniques (GCP/GMP, turbochargers, and aftercoolers (except as noted above)) constitute RACT for all emergency generators except TM01, for which tier certification emissions limits apply.

Table 4.6-2. Summary of DAQ RACT Analyses for MGMRI Emergency Generators

CT #	Control Technology	RACT?[165]	Discussion
1	SCR	No	MGMRI stated SCR may not be the best choice for emergency generators, per EPA, due to the brief steady-state operating time. SCR is considered technically feasible, with NO_x reductions up to 90%,[166] but even if it is technically feasible, it is not cost-effective. The capital cost is based on an estimate provided by W.W. Williams and other costs in the Caesars RACT analysis (Appendix 3). MGMRI did not provide any actual emissions, so DAQ used NAFB PTE-to-actual-emissions to get

[164] EPA-450/1-78-001, Control Techniques for Nitrogen Oxides Emissions from Stationary Sources-Second Edition, January 1978.
[165] Y = Yes; N = No; NA = Not Applicable or Not Available; A question mark (?) means that the determination is tentative pending additional information (usually, a cite from the manufacturer or source documenting a statement, such as a technology not being available for that make or model).
[166] EPA-453/R-93-032, Alternative Control Techniques Document-NO_X Emissions from Stationary Reciprocating Internal Combustion Engines, July 1993, p. 2-22.

CT #	Control Technology	RACT?[165]	Discussion
			actual emissions estimates for MGMRI. Unit 41 had the highest NAFB actual/PTE ratio: 1.861/8.07 = 0.231 = 23.1%; 15.12 • 0.231 = 3.49 tpy. CE = $7,021/ton, so SCR was rejected as not cost-effective.
2	SNCR	No	Although having a lower capital and operating cost, SNCR is not considered available for diesel engines because it operates best at temperatures of 1600–2000°F and diesel engine exhaust gas ranges from 800–1200°F.[167] SNCR also needs fuel-rich engine operation or the use of reducing agents, so its use is limited to rich-burn engines; CI diesel engines are generally lean-burning. In addition, the exhaust gas temperature makes SNCR unsuitable (Figure 4-2).[168]
3	DLN and SLN	NA	These technologies appear to be primarily for turbines, since no articles, documents, or websites indicated use of DLN or SLN on diesel engines.
4	Turbocharging	Yes	All but one of these units (TM01, but it is Tier-Certified) are already required to have a turbocharger, and all but seven (EX007–EX010 and NY27–NY29) are required to have an aftercooler.[169] Turbocharging alone doesn't appear to reduce NO_x emissions, but it may reduce other emissions; it is usually installed to increase output and can actually increase NO_x emissions if there is no aftercooler. Since compressing the air raises its temperature, engines with turbocharges usually also add aftercoolers to bring the temperature back down. Turbocharging combined with EGR does reduce NO_x emissions.[170]
5	GCP and GMP	Yes	These practices are the most common RACT determinations in the RBLC and are already being implemented through the Title V OP.[171]
6	Pre-stratified charge	No	EPA documents indicate that this technique is for spark ignition engines, not CI engines.[172]
7	EGR	No	EGR can reduce NO_x by 40% on low-load mobile diesels, but EPA notes it requires external hardware retrofits, some additional controls, and possibly cooling/cleaning of exhaust; downsides include substantial fouling of heat exchanger and flow passages, increased maintenance, substantial increases in CO and smoke, and increased wear. As of 1993, EGR was not being offered for production CI engines.[173] In addition, a study by NRDC on cleaning up diesel engine emissions found that EGR resulted in fuel penalties of 0–5%, was among the most costly of control options available, and increased PM emissions.[174] A web search turned up only a few companies offering EGR, and those often paired EGR with other controls (such as particulate), mainly on propulsion engines. EGR does not appear to be a viable RACT option.
8	ITR	No	If the engine already has an automated electronic control system for

[167] Marek Pronobis, Environmentally Oriented Modernization of Power Boilers, 2020, Chapter 4.4.2.

[168] Emission Factor Documentation, p. 2-18.

[169] The Title V permit requires, for example:

> Condition III.A.5.r. The permittee shall operate the diesel emergency generators with turbochargers and aftercoolers (EUs: MG17 through MG23), p. 25.

[170] Dond, DK, Gulhane, NP. Effect of a turbocharger and EGR on the performance and emission characteristics of a CRDI small diesel engine. *Heat Transfer*. 2022; 51: 1237- 1252. doi:10.1002/htj.22350

[171] For example, from the Title V permit (Condition III.A.5.p.): The permittee shall operate and maintain all diesel generators and fire pumps in accordance with the manufacturer's O&M manual for emissions-related components (EUs: MG17 through MG24, MG26 through MG28, MG51, and MG113).

[172] EPA-453/R-93-032, Alternative Control Techniques Document-NO_X Emissions from Stationary Reciprocating Internal Combustion Engines, July 1993, p. 5-14.

[173] Ibid, 5–85.

[174] Richard Kassel and Denise Bailey, Cleaning Up Today's Dirty Diesels, NRDC, 2005

CT #	Control Technology	RACT?[165]	Discussion
			injection, ITR is desirable because it only requires field adjustments to the unit. The MGMRI analysis does not mention the type of control system. The literature states that ITR degrades performance and longevity and increases CO, PM, CO, and HC. EPA literature backs up these concerns, including a 3% fuel penalty. If a unit is not already equipped for ITR, retrofit installation results in a CE = $6,674/ton, higher than the $5,500 threshold, making the technology not cost-effective.[175]
9	AFR adjustments	NA	DAQ makes no finding on its availability, but finds this control technology does not qualify as RACT because the energy and collateral pollutant disbenefits outweigh the benefits of potential emissions reductions.
10	Derating / increasing speed	No	DAQ finds this control technology does not qualify as RACT because the energy and collateral pollutant disbenefits outweigh the potential for RACT emissions reductions.
11	Inlet MAT adjustment / aftercooler	Y (if already on) No (if not already on)	DAQ estimates that the CE for retrofitting a cooler is about $15,000/ton based on the NAFB calculation for A03). DAQ concludes this control technology is available but not cost-effective and, therefore, does not qualify as RACT unless already required.
12	DWI	No	Assuming EPA's literature control level of 25–35% and using the mid-range of 30%, the CE = $11,603/ton. This estimate does not include the potential fuel penalty. DAQ finds this control technology is not RACT because it is not cost-effective.
13	Water/fuel emulsions	No	DAQ estimates cost-effectiveness at $8,503/ton and concludes this control technology is not cost-effective.
14	EPMS	No	DAQ finds this control technology does not qualify as RACT because the amount of additional NO_x emissions reductions through its use is likely negligible.
15	High-pressure fuel injection	No	DAQ concludes this control technology does not qualify as RACT because its effect on reducing NO_x emissions, and the ability to retrofit it for existing emission units, is highly uncertain.
16	Conversion to natural gas (from diesel)	No	Switching to natural gas for emergency generators is usually impractical due to the need to have a dependable fuel supply available during emergencies (natural gas storage onsite is often either not technically feasible or prohibitively expensive). However, generators can be converted to dual fuel so natural gas can be used during all nonemergency use and diesel can be used during emergencies (see #17). Costs would be about the same.
17	Conversion to dual fuel (diesel/natural gas)	No	There are companies specializing in converting to dual fuels (e.g., see https://engeniousengineering.com/ and https://dwppon.com /wp-ontent/uploads/ 2020/06/bifuel _compressed.pdf). Costs would include converting the generator to dual fuel (or to natural gas only, see #16) and the piping needed to supply the unit with natural gas. If natural gas is already available at the properties, the piping cost would be relatively low. Conversion cost for small diesels with turbochargers ranges from $8,000 to $12,000,[176] but this is for small engines, so DAQ doubled it to $24,000. Reductions of 20–30% NO_x are expected.[177] EPA documents are in the same range, with an estimated 26.5% reduction in NO_x between diesel and dual fuel engines.[178] CE = $5,286/ton, which indicates this technology is barely cost-effective as RACT, but the actual conversion cost may be considerably higher than assumed. In addition, the

[175] Based on data from EPA's ACT for NO_X emissions from ICE engines, p. 2-42, Table 2-14.

[176] https://finddiffer.com/how-much-does-it-cost-to-convert-a-diesel-engine-to-gas/

[177] Talus Park, Dual fuel conversion of a direct-injection diesel engine, West Virginia University Master's Thesis, 1999.

[178] EPA-453/R-93-032, Alternative Control Techniques Document-NO_X Emissions from Stationary Reciprocating Internal Combustion Engines, July 1993, p. 2-3.

CT #	Control Technology	RACT?[165]	Discussion
			estimate (1) includes only maintenance costs, and there are generally other annual costs; (2) assumes only $2,000 to hook up natural gas; (3) may not include direct and indirect costs in capital costs, and (4) does not address possible cost savings from using natural gas instead of diesel. Given the uncertainties, DAQ has determined that this technology will not be cost-effective.
18	Alternative fuels (other than natural gas)	NA	The literature indicates that other fuels are not available for these engines. Methanol and LNG are the main alternatives other than emulsions. Methanol has serious corrosive and toxic problems, is costly, and can be readily contaminated with water, even though NO_x reductions can reach 60%. LNG requires huge investments for storage and installation and has high CO emissions.[179] DAQ finds that alternative fuels are not RACT for these emergency generators because the costs and potential collateral pollutant disbenefits outweigh the benefits of potential emissions reductions.

[179] Issa, M., Ibrahim, H., Ilinca, A. and Hayyani, M.Y. (2019) A Review and Economic Analysis of Different Emission Reduction Techniques for Marine Diesel Engines. Open Journal of Marine Science, 9, 148-171. https://doi.org/10.4236/ojms.2019.93012

5.0 STORAGE TANKS AND OTHER VOC RACT

5.1 CALNEV PIPE LINE—LAS VEGAS TERMINAL

Calnev's LVT (Source ID: 13) is a bulk petroleum distribution terminal with a SIC code of 4226 and a NAICS code of 424710. The terminal receives petroleum fuel products via pipeline or truck and transfers gasoline, diesel, and biodiesel from storage tanks into trucks via loading racks. Denatured ethanol stored and distributed at the LVT is received via railcar; the terminal also has the capability to unload ethanol via tank trucks.

In 2017, LVT had a VOC PTE of 187.4 tpy and actual VOC emissions of 59.31 tpy. Since its NO_x PTE is below the major source applicability threshold, LVT is subject to major source VOC RACT, but not NOx RACT. In its RACT analysis (Appendix 6), LTV listed all the emission units potentially subject to VOC RACT. Most individual units have a PTE below 5 tons per year, but DAQ asked that LVT address at least a majority of the emission units that contribute to the major source's PTE.

LVT grouped individual emission units so their group PTE exceeded 5 tpy and then conducted RACT analyses on these groups: (1) storage tanks with a total PTE of 61.3 tpy VOC,[180] (2) a vapor recovery unit with a total PTE of 14.5 tpy VOC,[181] (3) loading racks with a total PTE of 65.7 tpy VOC,[182] (4) a remediation system with a total PTE of 37.7 tpy VOC,[183] and (5) fugitive components (e.g., valves, flanges, fittings, pump seals) with a total PTE of 6.6 tpy VOC. LVT also listed the emission units not evaluated for VOC RACT (Appendix 6, p. 2).

5.1.1 Storage Tanks

LVT included three vertical fixed roof tanks ("FRT"); four fixed roof tanks; 21 internal floating roof tanks ("IFR"); 12 external floating roof tanks ("EFR"); and three domed external floating roof tanks ("DEFR") in the analysis. Except for D01, a small 5.9-barrel (about 250-gallon) tank, and consistent with LVT's RACT analysis, DAQ did not include tanks below 1,000 gallons[184] in the RACT analysis after determining that it would not be cost-effective to impose emission controls on these units.

According to LVT, all the floating roof tanks except 501 (A27) and 522 (A18), which are authorized to store only denatured ethanol, are designed and permitted to store multiple liquids, but several of the tanks are authorized for only a few liquids.[185] LVT assumed that gasoline with a Reid vapor pressure (RVP) of 11 pounds per square inch (psi) represents the average annual vapor pressure of the gasoline stored and loaded at LVT, and DAQ agrees with this approach.

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[180] Table 3-1, LVT RACT Analysis. No tank has a PTE of 5 tpy or more.

[181] The vapor recovery unit is itself a control device that LVT says is considered BACT.

[182] There are 15 loading racks. Most of the 65.7 tpy PTE is from gasoline dispensing. Assuming each rack has the same PTE, 65.7/15 = 4.38 tpy per rack, less than the 5 tpy PTE threshold for RACT review.

[183] This system is also considered BACT, per LVT.

[184] One barrel equals 42 gallons or 160 liters.

[185] Diesel/Biodiesel only: A14-15; Jet Fuel and Diesel/Biodiesel: A23-24.

There are two main losses (VOC emissions) associated with storage tanks: working losses (during transfer of the stored liquid) and standing losses (due to evaporation resulting from temperature swings, seal leaks, etc.).

The following recommended RACT control measures apply to EFRT larger than 150,000 liters (approximately 943 barrels (bbl))[186] storing petroleum liquids. They do not apply to fixed roof tanks or tanks with or without internal floating roofs, nor do they apply to small production tanks. In general, RACT for EFRT is defined as follows:

- A welded EFRT equipped with primary metallic shoe or liquid-mounted seals is required to retrofit with a rim-mounted secondary seal if the true vapor pressure (TVP) of the stored liquid exceeds 27.6 kilopascals (kPa) (4 psi).[187,188]
- A welded or riveted EFRT equipped with primary vapor-mounted seals is required to retrofit with a rim-mounted secondary seal if the TVP of the stored liquid exceeds 10.5 kPa (1.5 psi).
- A riveted EFRT equipped with primary metallic shoe or liquid-mounted seals is also required to retrofit with a rim-mounted secondary seal if the TVP of the stored liquid exceeds 10.5 kPa (1.5 psi).

Information on the controls already on the tanks is included in the LVT analysis (Appendix 6, Table 3-1) and summarized in LVT's Title V OP, as shown in Table 5.1-1.

Table 5.1-1. Tank Control Requirements

EU	Facility ID	Control Requirements
A01	530	External floating roof with primary and secondary seals
A02	531	External floating roof with primary and secondary seals
A03	532	External floating roof with primary and secondary seals
A04	533	External floating roof with primary and secondary seals
A05	534	External floating roof with primary and secondary seals
A06	535	External floating roof with primary and secondary seals
A07	536	External floating roof with primary and secondary seals
A08	537	External floating roof with primary and secondary seals
A09	538	External floating roof with primary and secondary seals
A10	539	External floating roof with primary and secondary seals
A11	540	Internal floating roof with primary and secondary seals
A12	541	Domed external floating roof with primary and secondary seals
A13	524	Internal floating roof with primary and secondary seals
A14	542	Internal floating roof with primary seal
A15	543	Internal Floating Roof, primary Seal

[186] All of the tanks in Table 3-1 have a capacity greater than 950 bbl (approximately 39,900 gallons).

[187] For a Reid vapor pressure (RVP) of 11 psi, the TVP of 4 psi would be exceeded any time the stock temperature was higher than about 45 F. See: AP-42, Chapter 7, Figure 7.1-14a (https://www.epa.gov/sites/default/files/2020-10/documents/ch07s01.pdf) for the conversion, assuming S = 3.0.

[188] EPA-450/2-78-047, OAQPS No._ 1.2-116, Control of Volatile Organic Emissions from Petroleum Liquid Storage in External Floating Roof Tanks, December 1978.

EU	Facility ID	Control Requirements
A16	545	Internal floating roof with primary and secondary seals
A17	546	Internal floating roof with primary and secondary seals
A18	522	Internal floating roof with primary and secondary seals
A19	525	Fixed roof
A20	526	Fixed roof
A21	547	Internal floating roof with primary and secondary seals
A22	512	Fixed roof
A23	510	External floating roof with primary seal
A24	511	External floating roof with primary seal
A25	ASA Conductivity Improver	Fixed roof
A26	500 AIA	Fixed roof
A27	501	Internal floating roof with primary and secondary seals
A28	523	Internal floating roof with primary and secondary seals
A29	544	Internal floating roof with primary and secondary seals
A30	533 A	Fixed roof
A31	537 A	Fixed roof
A32	541 A	Fixed roof
A33	541 B	Fixed roof
A34	542D	Fixed roof
A35	542A	Fixed roof
A36	531A	Fixed roof
A37	542C	Fixed roof
A38	537 B	Fixed roof
A39	531B	Fixed roof
A45	548	Domed external floating roof with primary and secondary seals
A46	549	Domed external floating roof with primary and secondary seals
A47	550	Internal floating roof with primary and secondary seals
A48	551	Internal floating roof with primary and secondary seals
A53	548B	Fixed roof
A54	548A	Fixed roof
A56	513	Internal floating roof with primary and secondary seals

EPA's control technology documents indicate that for IFR and EFR tanks, the use of primary and secondary seals is the best control; all but four of these tanks are already equipped with primary and rim-mounted secondary seals, so RACT is the current technology. The four floating roof tanks with only primary seals (A14–15 and A23–24) are used only for diesel and biodiesel, which has a TVP at 60°F of only 0.006 pounds per square inch absolute (psia).[189] Therefore, the diesel-only tanks are not subject to CTG requirements and the current primary seals constitute RACT.

The fixed roof tanks are the most likely candidates for finding cost-effective add-on emissions controls, since they emit more than IFR and EFR tanks. EPA's CTG document for storage tanks states:

[189] AP-42, Chapter 7, Table 7.1-2.

> Existing fixed roof tanks with greater than 150,000-liter capacity containing petroleum liquids with true vapor pressure greater than 10.5 kilopascals should be controlled by retrofitting with internal floating roofs or equivalent external floating roofs, vapor recovery, vapor disposal systems, or other equivalent control technology. Bolted tanks generally cannot be retrofitted with internal floating roofs, and thus will require alternative equivalent control technology.[190]

Only low-volatility liquids are stored in these tanks, with the most volatile being “jet fuel” in Tank A22. Jet fuel could be either jet naphtha (JP-4) or jet kerosene (Jet A). JP-4 has a TVP at 60°F of 1.3 psia (8.97 kPa), below the TVP threshold in the EPA CTG for RACT.[191] DAQ concludes that RACT for the fixed roof tanks is current controls (primary rim seals).

5.1.2 Vapor Recovery Unit and Loading Racks

The 15 LVT loading racks have a total permitted throughput of 35,379,927 barrels/yr. Gasoline and diesel are loaded directly into trucks, while biodiesel, ethanol, and additives are blended during loading. Emissions are controlled by a collection system (98.7% capture efficiency) that captures vapor from the empty trucks as they are loaded; approximately 65 tpy of VOC are fugitive emissions not captured by the recovery system. The captured emissions are routed to a high-efficiency adsorption-absorption John Zink Vapor Recovery Unit (VRU) with an estimated 99.7% efficiency; the approximately 4,893 tpy treated by the VRU is reduced to about 14 tpy of VOC emissions from the VRU. LVT operates a flare as backup if the VRU is unable to operate.

LVT does not mention any RBLC searches for VOC controls for loading racks, so DAQ conducted an independent search to identify potentially available control technologies. A review of the 1977 CTG[192] for loading terminals indicates that a vapor control system with a flare as backup is considered RACT. The CTG mentions three systems (compression-refrigeration-absorption, refrigeration, and thermal oxidation), but the adsorption-absorption system appears to be different (DAQ found a 1976 patent on such a system). The best system the CTG mentioned was thermal oxidation (99+% efficiency). DAQ finds the John Zinc VRU at LVT, at 99.7% efficiency on captured VOC and with the backup flare, would qualify as RACT.[193]

The bulk of emissions from the loading rack are fugitive (65.7048 tpy, of which 64.37 tpy is from gasoline loading). The CTG indicates that fugitive emissions occur during truck filling as a result of faulty seals, overfilling, and other leakage (vapor capture efficiency is 98.70%), but does not address additional control measures for fugitive emissions from loading. For some sources, VOC fugitive emissions reductions from improving operating and maintenance practices may be feasible, but LVT’s system is already subject to the NSPS requirements in 40 CFR

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[190] EPA-450/2-77-036, EPA-450/2-77-036 (OAQPS No. l.~-089), p. 1-2. *Guideline Series: Control of Volatile Organic Emissions from Storage of Petroleum Liquids in Fixed-Roof Tanks*. December 1977. EPA Office of Air and Waste Management.

[191] Even if the fixed roof tanks were subject to CTG, the highest PTE, for Tank A19, is 1.84 tpy, which would make it very unlikely to have a cost-effective CE.

[192] EPA-450/2-77-026, “Control of Hydrocarbons from Tank Truck Gasoline Loading Terminals.” See also: “Control Techniques for Volatile Organic Emissions from Stationary Sources.” May 1978.

[193] The Title V permit specifies that the control system be maintained and operated per the manufacturer’s specifications (Condition III.B.3.n).

Part 60, Subpart XX, "Standards of Performance for Bulk Gasoline Terminals" (OP Condition III.B.3). This includes using the John Zinc system during loading, maintaining the gauge pressure to the delivery tank to no more than 4,500 pascals during loading, and operating so the pressure vacuum vents don't open if the system pressure is less than 4,500 pascals. Conditions III.B.3.q–u specify tanker loading requirements and measures to minimize vapor releases by minimizing gasoline spills, cleaning up spills as expeditiously as possible, covering all open gasoline containers with a gasketed seal when not in use, and minimizing gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices. DAQ identified no additional measures after conducting a literature search, so finds that RACT for the fugitive emissions from the loading racks consists of the requirements already in place.

5.1.3 Remediation Systems

LVT has two soil vapor extraction (SVE) systems (both permitted) to treat historical contamination of soil. The first SVE system, termed a "combustion system" in the analysis, has a 98.5% VOC destruction efficiency but is not currently being used; the second system, which is being used, consists of carbon beds and a fluidized bed reactor ("FBR") for 95+% control of the VOC. LVT used a control efficiency of 98.5% for the cost-effectiveness calculations regardless of the system in use.

LVT did not conduct a search of the RBLC or the literature to identify potential available control technology, so DAQ conducted an independent search and identified the following potential control technologies:

- Thermal destruction (e.g., direct flame thermal oxidation, catalytic oxidizers);
- Adsorption (e.g., granular activated carbon, zeolites, polymers);
- Biofiltration;
- Nonthermal plasma destruction;
- Photolytic/photocatalytic destruction;
- Membrane separation;
- Gas absorption; and
- Vapor condensation.

Both SVE and FBR are highly efficient combustion devices that burn most of the VOC in the extracted gas. LVT currently operates its FBR system in a manner that achieves the same level of emission reductions allowable for the SVE combustion system. Accordingly, DAQ concludes that these technologies, as applied based on contaminate treatment conditions, are equally effective. Replacing these systems with a different control technology, even if one of the other technologies had a control efficiency greater than the current system efficiency of 98.5%, would yield few additional emissions reductions from the estimated 37.57 tpy. DAQ concludes that replacing the existing control systems with a different control technology is not economically reasonable for RACT; therefore, the existing control system is RACT.

5.1.4 Fugitive Emissions

LVT states that it inspects fugitive components for leaks on a consistent basis and repairs any leaks in the system, and that "these leak monitoring protocols are considered to meet the requirements of RACT." DAQ supplemented LVT's analysis by first checking the RBLC, then documents such as EPA's "Control Techniques for Volatile Organic Emissions from Stationary Sources" (1978). This document discusses leaks found at petroleum refineries, but the information pertains to all pumps, valves, flanges, and other fugitive emissions at a variety of sources (see page 144, for instance). EPA notes that flanges produce the least fugitive emissions and that there are some pump and valve options when switching out old ones, but that for existing equipment, proper maintenance is the key to reducing leaks around packing and seals. DAQ finds that the extensive leak monitoring requirements already in LVT's Title V permit for the tanks and other equipment are sufficient to ensure compliance and therefore constitute RACT.

LVT is also subject to the leak monitoring requirements in 40 CFR Part 63, Subpart BBBBBB–National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities. The requirements in this recently promulgated standard represent the most effective control technology for leak detection. Although the standard regulates HAPs, these HAP emissions are generally also VOC emissions, so DAQ expects a similar level of emission reduction from LVT compliance with the standard. Among the many leak monitoring requirements in Subpart BBBBBB (at 40 CFR 63.11092(a)(1)(i)) is a requirement for the source to conduct vapor collection leak monitoring during a performance test on the vapor recovery system using Method 21, with a 500 ppm threshold for doing maintenance and repair. DAQ finds that using EPA Method 21 to monitor for leaks and repairing leaks with readings at or above 500 ppm (as methane) represent RACT for this equipment.

6.0 ELECTRIC UTILITY NO_x AND VOC RACT

6.1 INTRODUCTION

This section explains DAQ's case-by-case RACT determinations for NO_x and VOC for the two major sources in the electric utility sector. DAQ relied on information provided in the proposed RACT analyses for NV Energy (Appendix 7) and Saguaro Power Company (Appendix 8), supplementing these analyses where appropriate. Where the analyses provided cost estimates, DAQ adjusted calculation methodologies as needed, including equipment life and cost components, to assure a consistent approach.

This section does not repeat all the information from each source's proposed RACT analysis but highlights key information critical to the decision-making process. Refer to Appendices 7 and 8 (and supporting documentation) for the full scope of information considered in making the RACT determinations.

6.2 POTENTIALLY AVAILABLE CONTROL TECHNOLOGIES

Emission units at the affected electric utility sources include simple cycle combustion turbines (CTs), combined cycle units (CCUs), package boilers, cooling towers, emergency engines, and storage tanks; however, the only units that meet the VOC or NO_x RACT applicability thresholds are CTs, CCUs, and boilers. This section will thus be limited to NO_x and VOC control options for CTs and CCUs. With the exception of boilers, all other sources were below the DAQ applicability criteria (Section 4 provides a detailed discussion of boiler control technologies considered).

DAQ did not consider operating restrictions a viable control technology in identifying RACT because they do not usually control NO_x or VOC emissions during emission unit operations. They can, however, can be used to avoid applicability, including RACT requirements.

6.2.1 NO_x Control Technologies

6.2.1.1 Selective Non-Catalytic Reduction

In an SNCR control system, urea or ammonia is injected into boilers where the flue gas temperature is approximately 1,600°F to 2,100°F. At these temperatures, urea [$CO(NH_2)_2$] or ammonia [NH_3] reacts with NO_x, forming elemental nitrogen [N_2] and water without the need for a catalyst. Overall NO_x reduction reactions are similar to those for SCR. Multiple injection points are required to thoroughly mix the reagent into the boiler furnace. The limiting factor for a SNCR system is the ability to contact the NO_x with the reagent as the concentration decreases without resulting in excessive ammonia slip and without excessive ammonia decomposition before NO_x emissions can be reduced. SNCR is widely used in various types of boilers; however, the required residence time and temperature range is incompatible with gas turbines. DAQ is not aware of SNCR application to any gas turbine in the U.S. or worldwide; therefore, it is not a technically feasible control technology for any of the CTs or CCUs.

6.2.1.2 Selective Catalytic Reduction

SCR is a post-combustion treatment of the flue gas that involves the injection of ammonia into the system in the presence of a catalyst to convert NO_x emissions to nitrogen and water. SCR on boilers and CTs/CCUs works in essentially the same manner. "The catalyst allows the ammonia to reduce NO_X levels at lower exhaust temperatures than an alternative control technology called selective noncatalytic reduction (SNCR). Unlike SNCR, where the exhaust gases must be approximately 1400-1600°F, SCR can be utilized where exhaust gases are between 500°F and 1200°F, depending on the catalyst used" (Appendix 3, p. 2).

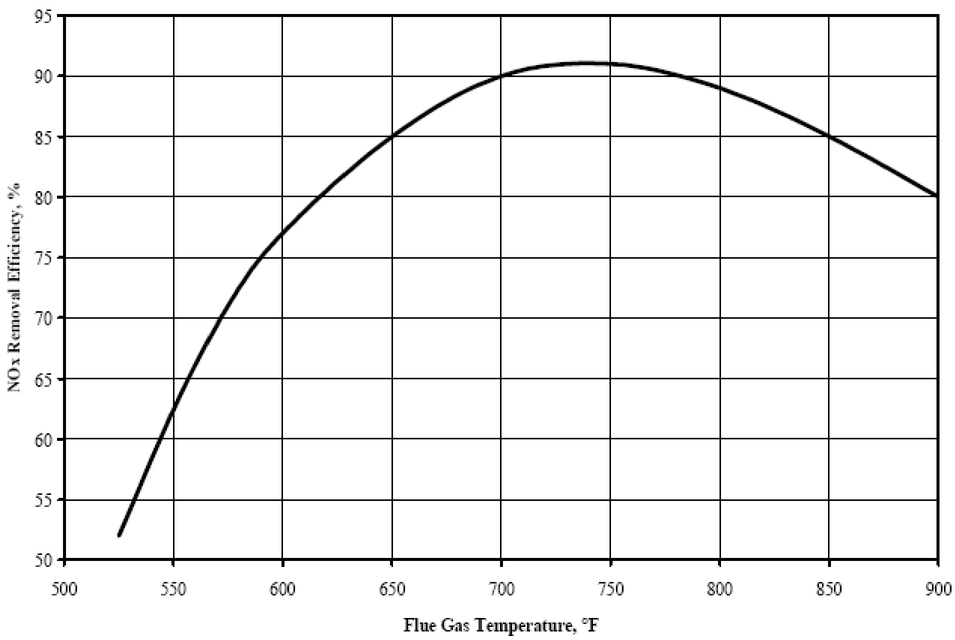

Figure 6-1. SCR-NO_X Removal versus Temperature[194]

6.2.1.3 Non-Selective Catalytic Reduction

NSCR is a post-combustion treatment of the flue gas that uses a catalyst (typically platinum) to convert NO_x, CO, and HC to water, CO_2, and nitrogen. Unlike SCR, which requires ammonia, NSCR utilizes unburnt hydrocarbons as a reducing agent. For NO_x removal, oxygen concentration is limited to less than 0.5% because the oxidation reactions tend to favor CO and HC. Because the oxygen concentration in turbine exhaust is significantly higher (12–18% vol),[195] NSCR is not considered feasible for any of the CTs or CCUs.

6.2.1.4 Catalytic Combustion

Catalytic combustion uses a specially designed combustor equipped with a catalyst to increase fuel oxidation rates, which enables lower combustion temperatures and reduced thermal NO_x

[194] *Selective Catalytic Reduction*, Chapter 2. June 2019. J. Sorrels, D. Randall, K. Schaffner, and C. Fry.
[195] "GE Turbine Emission Control," R. Pavri and G. Moore. Document GER-4211, GE Energy Services.

formation. Two vendors have produced catalytic combustor products designed for turbine applications:

- Rich Catalytic Lean (RCL) catalytic combustor (Precision Combustion, Inc.).
- Xonon Cool Combustion (SCR-Tech, LLC).[196]

The catalytic combustion technology owned by SCR-Tech is not currently being marketed or produced. While Precision Combustion actively markets the RCL combustor, DAQ could find no gas-fired CTs or CCUs (> 50 MW) installed with it; therefore, this technology is not considered feasible for any of the CTs or CCUs.

6.2.1.5 Catalytic Absorption/Oxidation

EMx™ Catalytic Absorption/Oxidation (the second generation of the SCONO$_x$™ NO$_x$ Absorber technology), owned by Miratech Corporation, is based on a proprietary catalytic oxidation and absorption technology. EMx™ uses a potassium carbonate (K_2CO_3) coated catalyst to reduce NO$_x$ and CO emissions from natural gas-fired gas turbines. The catalyst oxidizes CO to CO_2 and NO to NO_2. The NO_2 absorbs onto the catalyst to form potassium nitrite (KNO_2) and potassium nitrate (KNO_3). Dilute hydrogen gas is periodically passed across the surface of the catalyst to regenerate the K_2CO_3 coating. The regeneration cycle converts KNO_2 and KNO_3 to K_2CO_3, water, and elemental nitrogen. This makes the K_2CO_3 available for further absorption.

EMx™ technology is no longer being installed on new units; Miratech indicated it is strictly being serviced on units already equipped with this technology.[197] EMx™ was eliminated from consideration because it is not commercially available.

6.2.1.6 Water/Steam Injection

The mechanism of using water or steam injection for NO$_x$ reduction in turbines is similar to that of boilers. Water or steam injection into the combustion zone lowers the flame temperature, which reduces thermal NO$_x$ formation. However, because steam is not as effective as water in reducing thermal NO$_x$,[198] DAQ has eliminated steam injection from this evaluation.

Water injection can achieve a 70–80% reduction from uncontrolled levels for utility and large turbines. The typical range in the water-to-fuel ratio (WFR) is 0.33–2.48, although the optimal WFR for a gas-fired turbine is 1.0.[199] Actual reduction will depend on combustor geometry, injection nozzle design, and fuel-bound nitrogen content.

Water injection can be installed as a retrofit on many existing turbines, depending on combustor design and the availability of high-purity, filtered water. Compared with other NO$_x$ control

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[196] Xonon Cool Combustion technology was developed by Catalytica Energy Systems, which merged with NZ Legacy to form Renergy in 2007. In 2007, the SCR technology services were sold to SCR-Tech LLC.
[197] Appendix 8
[198] Water injection is more effective because “the high latent heat of water acts as a strong thermal sink in reducing flame temperature” (GE, *ibid*).
[199] *CAM Technical Guidance Document, Water/Steam Injection*, Chapter B.17. EPA 1998.

technologies, capital costs are lower and operating costs are generally higher due to the need for a water treatment system.[200]

Units with WSI may sometimes be able to further reduce NO_x emissions by increasing rates of steam or water injection, depending on combustor design. Increasing the injection rate reduces thermodynamic efficiency, which generally results in an increase in CO and VOC emissions, although this effect depends on turbine inlet temperature: the higher the inlet temperature, the greater the tolerance for increased injection without substantial increases in CO. Certain combustor designs may allow up to 1.4% compressor inlet water concentration at 1,900°F before CO increases.[201] However, all combustor designs are limited in the usability of WSI for NO_x control because increased injection rates reduce combustor operating stability and may eventually cause the combustor to flame out.

6.2.1.7 Dry Low NO_x Combustion

DLNC, also referred to as "Dry Low Emissions" (DLE) systems and LNB, generally refers to a turbine combustor design in which thermal NO_x is reduced by a combination of premixing air and fuel prior to combustion and then staging combustion to achieve optimal air/fuel mixing at all operating loads. Many existing CTs and CCUs can be retrofit with DLNC, although the combustors take up more space than conventional annular combustors and may not be feasible on all turbines. DLNC retrofits can achieve NO_x emissions of 9–25 ppm, depending on existing combustor design, although newer designs with additional staging (i.e., ULNB) can achieve even lower levels of emissions.

6.2.1.8 Good Combustion and Maintenance Practices

GCP and GMP involve operating the turbine to maximize energy output or thermal efficiency while maintaining optimized oxygen levels to assure complete combustion. GCP can also involve running in accordance with the manufacturer's recommended settings and preventative maintenance schedules (Appendix 4, p. 2-2; Appendix 5, p. 2-3).

6.2.2 Potentially Available VOC Control Technologies

6.2.2.1 Oxidation Catalysts

For natural gas turbine applications, the lowest CO and VOC emission levels are achieved using oxidation catalysts (OC) installed as post-combustion control systems. The typical OC is a rhodium or platinum (i.e., noble metal) catalyst on an alumina support material. The catalyst is typically installed in a reactor with flue gas inlet and outlet distribution plates. CO and VOC react with O_2 in the presence of the catalyst to form CO_2 and water according to the following equations:

Eq. 1. $$2CO + O_2 \rightarrow 2CO_2$$
Eq. 2. $$2C_nH_{2n+2} + (3n + 1)O_2 \rightarrow 2nCO_2 + (2n+2)$$

[200] "Combustion Turbine NO_X Control Technologies Memo," January 2022. Project No. 13527-002, EPA.
[201] "Gas Turbine Emissions and Control," R. Pavri and G. Moore. GER-4211, GE Energy Services.

Acceptable catalyst operating temperatures range from 400–1,250°F, with an optimum temperature range of 850–1,100°F. Below approximately 400°F, catalyst activity (and oxidation potential) is negligible. This temperature range is generally achievable with simple cycle GTs except at low-load startup and shutdown conditions. Oxidation catalysts have the potential to achieve approximately 90% reductions in "uncontrolled" emissions at steady-state operation.

6.2.2.2 Dry Low NO_x Combustion

The installation of DLNC is not generally considered an effective VOC control option, since the reduction in combustion temperature typically increases both CO and VOC emissions. However, a DLNC retrofit may reduce NO_x, CO, and VOC on some older turbines due to increased combustion efficiency.

6.2.2.3 Good Combustion Practices/Good Maintenance Practices

GCP and GMP involve operating the turbine to maximize energy output or thermal efficiency while maintaining optimized oxygen levels to assure complete combustion. GCP can also involve running the equipment in accordance with the manufacturer's recommended settings and preventative maintenance schedules (Appendix 4, p. 2-2; Appendix 5, p. 2-3).

6.3 CLARK GENERATING STATION

6.3.1 Background

NV Energy owns and operates the CGS (Source ID: 7) in Whitney, NV. CGS is an electric power generating facility (SIC code 4911, NAICS code 221112) consisting of four natural gas-fired combined cycle combustion turbines (no supplemental firing)[202] and thirteen natural-gas fired simple cycle combustion turbines. Other emissions sources include two cooling towers, a diesel-powered emergency generator, a diesel-powered emergency fire pump, and gasoline dispensing operations. Table 6.3-1 summarizes affected units, current control equipment, and NO_x and VOC emission limits.

[202] Turbine vintage is approximately 1980.

Table 6.3-1. CGS RACT-Affected Units

Emission unit		Description	Date of Commercial Operation	Control(s)	Emission Limits	
					NO_X	VOC
A00704D (Unit 4)		Natural gas-fired CT (60 MW)	1973	None	1732.6 tpy	None
Unit 10	A00701A (Unit 5)	Natural gas-fired CCU (85 MW)	~1980	LNB	360 tpy 5 ppm@15% O_2 (1-hour) 19.11 lb/hr	
	A00702B (Unit 6)					
Unit 9	A00705 (Unit 7)	Natural gas-fired CCU (85 MW)	~1980	LNB		
	A00708 (Unit 8)					
A27–A38 (Units 11–22)		Natural gas-fired CTs (57.9 MW)	2008	SCR/water injection Oxidation catalyst	30.96 tpy 5 ppm @ 15% O_2 (1-hour) 11.01 lb/hr	

CGS currently operates as a major source under the conditions in its Title V OP (Source ID: 257), issued by DAQ. Since the 40 CFR Part 70 major-source classification is the same as the moderate attainment area major-source classification, RACT is required only if the permitted PTE for either VOC or NO_x exceeds the Part 70 major source threshold. According to the source PTE summary in its current Title V OP, the facility's NO_x PTE is 2,467 tpy and its VOC PTE is 217 tpy. The only units with a VOC PTE greater than 5 tpy are Units 4 and Units 5–8; the only units with a NO_x PTE greater than 5 tpy are Units 4, 5–8, and 11–22 (all CTs/CCUs). The PTE for both NO_x and VOC for all other sources is below 5 tpy. CGS is therefore subject to RACT for NO_x for all turbines and VOC for Units 4 and 5–8.

6.3.2 RACT Analysis

DAQ conducted the following RACT analysis for NO_x and VOC using data and information provided by NV Energy[203] as noted and where applicable.

6.3.2.1 <u>NO_x RACT Analysis</u>

6.3.2.1.1 Baseline Emissions

Baseline emissions establish the basis for the cost-effectiveness of each control option. DAQ used emissions data provided by NV Energy in this determination. For Unit 4, the baseline emissions were selected as the highest two-year average in the 2017–2021 period.[204] Because Units 5–8 are identical units with similar dispatch, the baseline emissions for these were selected as the highest two-year average in the 2017–2021 period for a single unit.[205] The baseline emissions for Units 11–22 also were selected as the highest two-year average in the 2017–2021 period for a

[203] Appendix 7

[204] The highest two-year average NO_X emissions for Unit 4 is 37.65 tpy (2020–2021).

[205] The highest two-year average NO_X emissions for Units 5–8 is 14.30 tpy (Unit 7, 2020–2021).

single unit.[206, 207] Actual emissions data were used for the cost evaluation of all units because total emissions for the facility were well below 70% of PTE.

6.3.2.1.2 Potential Control Technologies

Table 6.3-2 lists the potential control technologies considered for each unit. These technologies are consistent with the potential retrofit options in EPA guidance for combustion turbines.[208] Certain technologies were not considered technically feasible so were eliminated from consideration, as discussed below.

Table 6.3-2. Technical Feasibility of NO_X Control Technologies (CGS)

Control Technology	Unit 4	Units 5–8	Units 11–22
SCR	Yes	Yes	Already equipped; increased ammonia injection is not technically feasible
DLNC	No	Already equipped	Yes
Water Injection	Possibly	No	Already equipped; increased water injection is not technically feasible
GCP	Yes	Yes	Yes

For Unit 4, DLNC was eliminated from consideration because the vendor indicated[209] that the only retrofit option (GE 7B DLN1+) for this unit has never been implemented on this turbine frame. The addition of water injection was considered technically feasible for this evaluation, although further investigation would be required to confirm whether the retrofit has been demonstrated in practice on similar turbines.[210]

For Units 5–8, the addition of water injection was eliminated from consideration because the existing combustors were not designed for water injection and would have to be replaced.[211]

For Units 11–22, the use of increased ammonia injection rates with the existing SCR configuration was eliminated from consideration. The vendor indicated that adding ammonia beyond current design specifications would flood the catalyst with ammonia and reduce NO_x removal.[212] Installation of DLNC is considered a feasible retrofit option, although the new combustor would not incorporate WSI.

[206] The highest two-year average NO_X emission for Units 11–22 is 4.37 tpy (Unit 14, 2017–2018).
[207] DAQ also reviewed the 10-year forecasted dispatch of each unit and compared that to the highest two-year average operation in the preceding five years (2017–2021) using data provided by NV Energy. Because forecasted operation is significantly less than the maximum two-year annual average for each unit, use of the maximum two-year annual average NO_X emissions is a conservative assumption (Appendix 7).
[208] "Alternative Control Techniques Document–NO_X Emissions from Stationary Gas Turbines," January 1993. EPA.
[209] Appendix 7
[210] GE provides a water injection kit for MS7001B (Frame 7B) turbines, but more information is needed to determine whether it has been successfully installed and operated on other turbines.
[211] Appendix 7b
[212] Appendix 7b

6.3.2.1.3 Control Equipment Costs

All control equipment costs are based on vendor estimates provided by NV Energy except as noted. Estimates have been modified as follows to provide consistency between RACT determinations for the various units:

- Total capital investment (TCI) includes initial capital investment (equipment cost only) and direct costs (direct installation cost only).
- Annualized TCI is calculated using the estimated equipment life of the various control options as specified in EPA's Cost Strategy Tool (CoST).[213] DAQ assumed an interest rate of 7.14% based on justification provided by NV Energy.[214]
- Annual operating costs include catalyst replacement cost only (for SCR options).

Potential energy impacts for certain upgrade options and several of the cost components described in the *EPA Air Pollution Control Cost Manual* were not included in order to simplify the analysis. Estimated costs are thus considered conservative and likely understate the actual costs associated with each control option; see Appendix 9 for detailed cost-effectiveness calculations.

For Unit 4, the SCR equipment, installation, and catalyst costs are based on a vendor estimate provided by NV Energy.[215] Estimated costs for a water injection retrofit are based on CoST,[216] adjusted for inflation. No additional costs are associated with the implementation of GCP.

For Units 5–8, SCR equipment, installation, and catalyst costs are based on the Unit 4 SCR cost estimate, scaled according to the "six-tenths factor" methodology.[217]

For Units 11–22, total installed LNB costs were estimated based on a vendor cost estimate for Unit 4 provided by NV Energy.

6.3.2.1.4 Control Equipment Performance

For Unit 4, the achievable emissions level for the SCR retrofit option (4 ppm @ 15% O_2) is based on vendor data provided by NV Energy. The achievable emissions level for installation of water injection is based on the lowest RBLC determination for a similarly equipped unit (25 ppm @ 15% O_2).[218] The achievable emissions level for GCP assumes the current level of emissions will be maintained (~120 ppm @ 15% O_2).

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[213] CoST version 4.1

[214] Appendix 7

[215] Appendix 9

[216] EPA CoST version 4.1

[217] The rule of 'six-tenths' refers to a cost scaling method that can be used to estimate the cost of a similar item of different size or capacity based on the equation: $Cost_1/Cost_2 = (MW_1/MW_2)^{0.6}$

[218] The lowest RBLC determination for the period 2012–2022 for CTs equipped with water injection is 25 ppm@15% O_2 (see Appendix 10). Further investigation would be required to determine if this level of performance has been achieved on a similar turbine retrofit.

For Units 5–8, the achievable emissions level for the addition of SCR with the existing DLNC (DLNC/SCR) is based on the lowest RBLC determination (2 ppm at 15% O_2) for a similarly equipped unit.[219]

For Units 11–22, the achievable emissions level for the installation of DLNC with the existing SCR system (DLNC/SCR) is based on the lowest RBLC determination (2 ppm at 15% O_2) for a similarly equipped unit.[220]

6.3.2.1.5 Benefits/Disbenefits

SCR. SCR converts NO_x (NO and NO_2) to nitrogen and oxygen by reacting the NO_x compounds with ammonia in the presence of a catalyst. However, excess ammonia ("ammonia slip") is required to account for non-uniform distribution of gases across the catalyst bed. The amount of slip required to maintain NO_x removal efficiency also increases over time due to catalyst deactivation. Because ammonia is a contributor to atmospheric fine particle formation, excess ammonia presents an adverse environmental impact. Other environmental concerns include accidental release of stored ammonia and the disposal of spent catalyst, which contains vanadium and/or titanium. SCR also presents an adverse energy impact, as the increased pressure drop across the catalyst bed reduces turbine efficiency.

DLNC. Maximum reduction in NO_x is typically achievable only at higher load conditions with premixed operation (< 75% load). A significant lack of turn-down capability may be an issue for peaking units or units with variable demand. In addition, decreasing the firing temperature may increase CO and VOC emissions.

DLNCs have a lower combustion efficiency than conventional combustors, which adversely affects fuel efficiency for these units. The source would have to purchase additional generating capacity elsewhere to maintain total system generating capacity. Units equipped with water injection would incur an energy penalty due to the loss of power augmentation.[221]

Water Injection. Water injection increases power output due to the increased mass flow needed to maintain the turbine inlet temperature. However, it also reduces combustion efficiency, as some of the energy from the combustion gases is needed to overcome the latent heat of vaporization of the water, which can result in emissions increases of CO and VOC. It also causes non-uniform heat release within the combustor, which can create pressure oscillations that induce turbine vibration. Although combustor modifications can reduce the effects of these oscillations, they are not completely eliminated, which may affect equipment life.

[219] RBLC determinations for the period 2012–2022 for CCUs equipped with SCR/DLN range from 2–3 ppm @ 15% O_2 (see Appendix 10)
[220] RBLC determinations for the period 2012–2022 for simple cycle CT equipped with SCR/DLN range from 2-3.1 ppm @ 15% O_2 (see Appendix 10)
[221] Appendix 7

6.3.2.1.6 RACT Determination

Table 6.3-3 provides a summary of the incremental control efficiency, achievable level of emissions, and cost-effectiveness of each control option used in the RACT determination for each unit. Additional supporting calculations are provided in Appendix 9.

Table 6.3-3. NO_x RACT Summary (CGS)

Control Equipment	Incremental Control Efficiency (%)	Achievable Emissions (ppm@15% O_2)	Cost Effectiveness ($/ton)
Unit 4			
SCR	97%	4	$56,000
Water Injection	79%	25	$114,000
GCP	N/A	~120	N/A
Unit 5 – 8			
SCR/LNB	60%	2	$294,000
LNB (existing controls)	N/A	5	N/A
Units 11 – 28			
SCR/LNB	60%	2	$803,000
SCR with WSI (existing controls)	N/A	5	N/A

Table 6.3-4 summarizes the RACT determination for each unit. For Unit 4, DAQ determines that the existing use of GCP represents RACT. The annual NO_x limit of 1,732.6 tpy (including startup, shutdown, and testing/tuning operation) does not require any specific control, so by itself does not establish RACT; DAQ has thus determined that RACT for NO_x consists of an emissions limit of 120 ppm @ 15% O_2[222] during normal operation, with compliance to be determined by adhering to GCP. RACT during startup, shutdown, and other non-normal operation is also determined to be adherence to GCP during each of those modes of operation; emissions are considered too variable to establish an emissions limit, so the work practice standard of GCP is RACT. All other technically feasible upgrade options were rejected due to excessive cost ($56,000–$114,000/ ton).

Table 6.3-4. Proposed RACT-Based NO_x Emission Limitations/Work Practices (CGS)

Emission Unit	Emission Limitation/Work Practice		Monitoring Requirements
	Normal Operation	Startup/Shutdown	
Unit 4	120 ppm @ 15% O_2 GCP	GCP	Follow existing permit conditions
Units 5–8	5 ppm @ 15% O_2 (one-hour average)	GCP	CEMS (follow existing permit conditions)
Units 11–22			

For Units 5–8 and 11–22, DAQ determines that the existing NO_x limits of 5 ppm @ 15% O_2 represent RACT for all units (excluding startup and shutdown). All technically feasible upgrade options were rejected due to excessive cost (> $294,000/ton for all units). Compliance shall be

[222] Based on existing PTE of 1,732.6 tpy, heat input limit of 899 MMBtu/hr, and continuous annual operation (8,760 hr/yr).

demonstrated using the existing continuous emission monitoring system (CEMS) on each unit based on a one-hour average. RACT during startup, shutdown, and other non-normal operation is also determined to be adherence to GCP during each of those modes of operation; emissions are considered too variable to establish an emissions limit, so the work practice standard of GCP is RACT. NV Energy shall also follow the compliance requirements during startup and shutdown operation for each unit outlined in the source's current OP.[223]

Since the current OP does not adequately reflect the monitoring, recordkeeping, and reporting requirements needed to ensure compliance with GCP, the permit will be revised to require that the permittee (1) develop a best operating practices document that includes manufacturer's recommended O&M procedures (or other industry-accepted standards) and (2) provide adequate recordkeeping to ensure the procedures are being implemented.

6.3.2.2 VOC RACT Analysis

The VOC RACT analysis includes Units 4–8, which are not currently equipped with any VOC controls. Units 11–22 are already equipped with oxidation catalyst limiting VOC PTE to less than 5 tpy and have therefore been excluded from the analysis.

6.3.2.2.1 Baseline Emissions

DAQ applied the same approach as the NO_x RACT evaluation to establish baseline emissions.[224] For Unit 4, the baseline emissions were selected as the highest two-year average in the 2017–2021 period.[225] Because Units 5–8 are identical units with similar dispatch, the baseline emissions for these were selected as the highest two-year average in the 2017–2021 period for a single unit.[226] The baseline emissions for Units 11–22 also were selected as the highest two-year average in the 2017–2021 period for a single unit.[227, 228] Actual emissions data were used for the cost evaluation of all units because total emissions for the facility were well below 70% of PTE.

6.3.2.2.2 Potential Control Technologies

Table 6.3-5 lists the potential control technologies considered for each unit. These technologies are consistent with the potential retrofit options identified in EPA guidance for combustion turbines.[229] Certain technologies were not considered technically feasible and eliminated from consideration, as discussed below.

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[223] Part 70 Operating Permit, Source ID 7, Clark Generating Station, Issued on October 5, 2020.
[224] Appendix 7
[225] The highest two-year average VOC emissions for Unit 4 is 2.05 tpy (2020-2021).
[226] The highest two-year average VOC emissions for Units 5–8 is 4.57 tpy (Unit 7 - 2020-2021).
[227] The highest two-year average VOC emissions for Units 11–22 is 0.48 tpy (Unit 14 - 2017-2018).
[228] DAQ also reviewed the 10-year forecasted dispatch of each unit and compared that to the highest two-year average operation in the preceding five years (2017–2021) using data provided by NV Energy. Because forecasted operation is significantly less than the maximum two-year annual average for each unit, the use of the maximum two-year annual average NO_X emissions is a conservative assumption (see Appendix 7).
[229] *Air Pollution Control Cost Manual (6th edition),* Chapter 3.2 (VOC Destruction Controls). January 2002, EPA.

Table 6.3-5. Technical Feasibility of VOC Control Technologies (CGS)

Control Technology	Unit 4	Units 5–8
DLNC	No	Already equipped
OC	Yes	Yes
GCP	Yes	Yes

The only option considered technically infeasible was a DLNC upgrade for Unit 4. Improved combustion efficiency may reduce VOC emissions, although (as discussed above) a DLNC retrofit for this turbine frame has not been demonstrated in practice.

6.3.2.2.3 Control Equipment Costs

DAQ applied the same methodology for estimating costs as the NO_x RACT analysis. As noted above (Section 6.3.2.1.3), energy impacts and certain cost components described in the *EPA Air Pollution Control Cost Manual* were not included in order to simplify the analysis, which may understate actual costs associated with each control option (Appendix 9).

For Units 5–8, equipment, installation, and catalyst costs are based on a vendor estimate provided by NV Energy.[230] For Unit 4, oxidation catalyst (OC) costs are based on the Unit 4 vendor estimate and scaled using the "six-tenths factor" methodology. No additional costs are associated with the implementation of GCP.

6.3.2.2.4 Control Equipment Performance

For Unit 4, OC control effectiveness is based on a vendor estimate of 80% removal efficiency provided by NV Energy. For Units 5–8, OC control effectiveness is based on a vendor estimate of 2 ppm @ 15% O_2 provided by NV Energy.[231] Control effectiveness resulting from implementation of GCP is based on maintaining the current level of VOC emissions.

6.3.2.2.5 Benefits/Disbenefits

Oxidation Catalysts. The environmental impact of OC use includes potential increases of NO_x from oxidation of NO and SO_3 formation resulting from oxidation of SO_2, both of which are precursors to formation of acid rain. Energy impacts include a reduction in turbine efficiency caused by an increase in exhaust back pressure across the catalyst bed.

6.3.2.2.6 RACT Determination

Table 6.3-6 provides a summary of the incremental control efficiency, achievable level of emissions, and cost-effectiveness of each control option used in the RACT determination for each unit. Additional supporting calculations can be found in Appendix 9.

[230] Appendix 7a

[231] See Appendix 7b. DAQ considered applying a more conservative removal efficiency assumption of 95% for Units 4–8, although cost effectiveness would be well above the acceptable cost threshold. The vendor would have to provide further justification of the feasibility of achieving such levels of emissions reduction.

Table 6.3-6. CGS VOC RACT Summary

Control Equipment	Incremental Control Efficiency (%)	Achievable Emissions (tpy)	Cost Effectiveness ($/ton)
Unit 4			
Oxidation Catalyst	80%	0.41	$318,000
Good Combustion Practices	N/A	2.05	N/A
Units 5 – 8			
Oxidation Catalyst	88%	0.57	$143,000
Good Combustion Practices	N/A	4.57	N/A

Table 6.3-7 summarizes the RACT determination for each unit. For Unit 4, DAQ determines that the existing requirement to use GCP represents RACT. The VOC limit of 94.5 tpy (including startup, shutdown, and testing/tuning operation) does not require any specific control, so by itself does not establish RACT. DAQ has thus determined that RACT for VOC consists of an emissions limit of 21.6 lb/hr[232] during normal operation, with compliance to be determined by adhering to GCP. RACT during startup, shutdown, and other non-normal operation is also determined to be adherence to GCP during each of those modes of operation; emissions are considered too variable to establish an emissions limit, so the work practice standard of GCP is RACT. The use of oxidation catalyst has been eliminated due to excessive cost (~$318,000/ton).

Table 6.3-7. Proposed RACT-Based VOC Emission Limitations (CGS)

<table>
<tr><th rowspan="2">Emission unit</th><th colspan="2">Emission Limitation/Work Practice</th><th rowspan="2">Monitoring Requirements</th></tr>
<tr><th>Normal Operation</th><th>Startup/Shutdown</th></tr>
<tr><td>Unit 4</td><td colspan="2">21.6 lb/hr
GCP</td><td rowspan="2">Unit 4</td></tr>
<tr><td>Units 5–8</td><td>5.01 lb/hr
GCP</td><td>GCP</td></tr>
</table>

For Units 5–8, DAQ determines that the existing VOC limit of 5.01 lb/hr (excluding startup, shutdown, and testing/tuning operation) represents RACT based on the application of GCP. OC use was eliminated due to excessive cost (> $143,000/ton for all units). RACT during startup, shutdown, and other non-normal operation is also determined to be adherence to GCP during each of those modes of operation; emissions are considered too variable to establish an emissions limit, so the work practice standard of GCP is RACT. NV Energy shall also follow the compliance requirements during startup and shutdown operation for each unit outlined in the source's current OP.[233]

Since the current OP does not adequately reflect the monitoring, recordkeeping, and reporting requirements needed to ensure compliance with GCP, the permit will be revised to require that the permittee (1) develop a best operating practices document that includes manufacturer's recommended O&M procedures (or other industry-accepted standards) and (2) provide adequate recordkeeping to ensure the procedures are being implemented.

[232] Based on existing PTE of 94.5 tpy continuous annual operation (8,760 hr/yr).
[233] Title V OP, issued October 5, 2020.

6.4 SUN PEAK GENERATING STATION, LAS VEGAS

6.4.1 Background

NV Energy owns and operates the SPGS (Source ID: 423). SPGS is an electric power generating facility (SIC code 4911, NAICS code 221112) consisting of three natural gas-fired simple cycle combustion turbines, and one 81-hp diesel power emergency generator with a diesel storage tank. Table 6.4-1 provides a summary of the affected units, current control equipment, and NO_x and VOC emission limits.

Table 6.4-1. SPGS RACT-Affected Units

Emission Unit	Description	Date of Commercial Operation	Control(s)	Emission Limits (all 3 units combined)	
				NO_x	VOC
A01 (Unit 3)	Natural gas/oil-fired CT (84.5 MW)	1991	Water injection	**Natural Gas**[234] 249.11 tpy 143.00 lb/hr 42 ppmvd@15% O_2 **#2 Oil**[235] 249.02 tpy 227.00 lb/hr 65 ppmvd@15% O_2	**Natural Gas**[236] 3.59 tpy 2.06 lb/hr **#2 Oil**[237] 4.94 tpy 4.50 lb/hr
A02 (Unit 4)	Natural gas/oil- fired CT (84.5 MW)	1991	Water injection		
A03 (Unit 5)	Natural gas/oil-fired CT (84.5 MW)	1991	Water injection		

SPGS is a Part 70 major stationary source for NO_x, a synthetic minor source for SO_2, and a minor source for all other pollutants. It currently operates as a major source under the conditions in its Title V OP (Source ID: 423), issued by DAQ. Since the 40 CFR Part 70 major-source classification is the same as the moderate attainment area major-source classification, RACT is required only if the permitted PTE for either VOC or NO_x exceeds the Part 70 major source threshold. According to the source PTE summary in its current Title V OP, the facility's NO_x PTE is 249 tpy (gas- or oil-firing) and its VOC PTE is 7.26 tpy. The source is subject to NO_x or VOC RACT for any emission units whose NO_x or VOC PTE is at least 5 tpy. For the turbines, NO_x PTE is 249 tpy (oil or gas combustion); VOC PTE is 3.59 tpy for natural gas combustion and 4.94 tpy for oil combustion. Therefore, the turbines are subject to NO_x RACT but not VOC RACT. The PTE for both NO_x and VOC for the emergency generator is below 5 tpy, so it is not subject to RACT. SPGS is subject to RACT for NO_x for all turbines only, since NO_x and VOC emissions for all other sources are below the DAQ guidelines for RACT applicability (5 tpy).

6.4.2 NO_x RACT Analysis

DAQ conducted the following analysis using data and information in the RACT analysis provided by NV Energy[238] as noted and where applicable.

[234] NSR ATC Modification 1, Revision 2 (04/29/10), AQR 12.5.2.6(b)
[235] NSR ATC Modification 1, Revision 2 (04/29/10), AQR 12.5.2.6(b)
[236] Title V Operating Permit (08/24/22), AQR 12.5.2.6(b)
[237] NSR ATC Modification 1, Revision 2 (04/29/10), AQR 12.5.2.6(b)
[238] Appendix 7

6.4.2.1 Baseline Emissions

Baseline emissions establish the basis for the cost-effectiveness of each control option. DAQ used emission data provided by NV Energy for this determination. Because Units 3–5 are identical units with similar dispatch, the baseline emissions were selected as the highest two-year average in the 2017–2021 period for a single unit.[239] Actual emissions data were used for the cost evaluation because total emissions for the facility were well below 70% of PTE.

6.4.2.2 Potential Control Technologies

Table 6.4-2 lists the potential control technologies considered for each unit. These are consistent with the potential retrofit options identified in EPA guidance for combustion turbines.[240] Certain technologies were not considered technically feasible so were eliminated from consideration, as discussed below.

Table 6.4-2. Technical Feasibility of NO_X Control Technologies (SPGS)

Control Technology	Units 3–5
SCR	Yes
DLNC	Yes
SCR + DLNC	Yes
Increased water injection	No
GCP	Yes

Installation of DLNC is considered a feasible option, but water injection would have to be eliminated because the new burners would not support it. DAQ also considered the use of increased water injection as a relatively inexpensive method of further NO_X reductions, with the possibility of achieving a RACT level of 25 ppmv 15% O_2. However, this option was eliminated from consideration based on vendor information indicating these units are not capable of meeting this level of emissions with the current combustors.[241] The combination of DLNC and SCR is considered technically feasible, but it was eliminated from further consideration because the vendor performance estimate for SCR is comparable to the performance of DLNC with SCR based on the lowest RBLC determinations for similar equipped units (see discussion below in Section 6.4.3.2.1).

6.4.2.3 Control Equipment Costs

All control equipment costs are based on vendor estimates provided by NV Energy except as noted. Estimates have been modified as follows to provide consistency between RACT determinations for the various units:

239 The highest two-year average for NO_X emissions for Units 3–5 is 32.19 tpy (Unit 3, 2020–2021).
240 "Alternative Control Techniques Document–NO_X Emissions from Stationary Gas Turbines," January 1993. EPA.
241 Appendix 7b

- TCI includes initial capital investment (equipment cost only) and direct costs (direct installation cost only).
- Annualized TCI is based on the estimated equipment life of the various control options using CoST.[242] DAQ assumed an interest rate of 7.14% based on justification provided by NV Energy.[243]
- Annual operating costs include catalyst replacement cost only (for SCR options).

Potential energy impacts for certain upgrade options and several of the cost components described in the *EPA Air Pollution Control Cost Manual* were not included in order to simplify the analysis. Estimated costs are thus considered conservative and likely understate the actual costs associated with each control option (Appendix 9).

Total installed SCR costs are based on a vendor estimate provided by NV Energy. SCR catalyst replacement cost is based on estimated catalyst costs for CGS Unit 4.[244] LNB total installed cost is based on a vendor estimate for CGS Unit 4 and was scaled using the “six-tenths factor” methodology.

6.4.2.3.1 Control Equipment Performance

The achievable emissions level for the SCR (2 ppm @ 15% O_2) and DLNC (9 ppm @ 15% O_2) options are based on vendor data provided by NV Energy.[245] The achievable emissions level for the combination of SCR and DLNC is comparable to performance with SCR only, based on the vendor data. The lowest RBLC determination for a gas-fired simple cycle CT with SCR and DLNC is 2 ppm @ 15% O_2.[246]

6.4.2.3.2 Benefits/Disbenefits

SCR. SCR converts NO_x to nitrogen and oxygen by reacting the NO_x compounds with ammonia in the presence of a catalyst. However, ammonia slip is required to account for non-uniform distribution of gases across the catalyst bed. The amount of slip required to maintain NO_x removal efficiency also increases over time due to catalyst deactivation. Because ammonia is a contributor to atmospheric fine particle formation, excess ammonia presents an adverse environmental impact. Other environmental concerns include accidental release of stored ammonia and disposal of spent catalyst, which may contain vanadium and/or titanium. SCR also presents an adverse energy impact, as the increased pressure drop across the catalyst bed reduces turbine efficiency.

DLNC. Maximum reduction in NO_x is typically achievable only at higher load conditions with premixed operation (< 75% load). A significant lack of turn-down capability may be an issue for

[242] *CoST* version 4.1
[243] Appendix 7
[244] Appendix 7a
[245] Appendix 7
[246] RBLC determinations for the period 2012–2022 for CTs equipped with SCR/DLNC range from 2-3.1 ppm @ 15% O_2 (see Appendix 10).

peaking units or units with variable demand. In addition, decreasing the firing temperature may increase CO and VOC emissions.

DLNC have lower combustion efficiency than conventional combustors, which adversely affects fuel efficiency for these units. The source would need to purchase additional generating capacity elsewhere to maintain total system generating capacity. Units equipped with water injection would incur an energy penalty due to the loss of power augmentation.[247]

6.4.3 RACT Determination

Table 6.4-3 lists the incremental control efficiency, achievable level of emissions, and cost-effectiveness of each control option used in the RACT determination for each unit. Additional supporting calculations are in Appendix 9.

Table 6.4-3. NO_x RACT Summary (SPGS)

Control Equipment	Incremental Control Efficiency (%)	Achievable Emissions (ppm @ 15% O_2)	Cost Effectiveness ($/ton)
Units 3-5			
SCR	95%	2	82,700
LNB	76%	9	47,700
Water Injection (existing controls)	N/A	42	N/A

Table 6.4-4 summarizes the RACT determination for each unit.

Table 6.4-4. Proposed RACT-Based NO_x Emission Limitations (SPGS)

Emission unit	Emission Limitation/Work Practice		Monitoring Requirements
	Normal Operation	Startup/Shutdown	
Unit 3–5	42 ppm @ 15% O2 (three-hour average)	GCP	CEMS (follow existing permit requirements)

DAQ determines that the existing NO_x limit of 42 ppmvd @ 15% O_2 (3-hr average) while firing natural gas (excluding startup, shutdown, and testing/tuning operation) represents RACT based on the use of existing NO_x controls. All upgrade options have been eliminated due to excessive cost (> $48,000/ton for all options/units). Compliance shall be demonstrated using CEMS, according to the monitoring and reporting procedures in the source's current OP. RACT during startup, shutdown, and other non-normal operation is also determined to be adherence to GCP during each of those modes of operation; emissions are considered too variable to establish an emissions limit, so the work practice standard of GCP is RACT. NV Energy shall also follow the compliance requirements during startup and shutdown operation for each unit outlined in the source's OP.

Since the current OP does not adequately reflect the monitoring, recordkeeping, and reporting requirements needed to ensure compliance with GCP, the permit will be revised to require that the permittee (1) develop a best operating practices document that includes manufacturer's

[247] See Appendix 7. Energy impacts were not accounted for in DAQ's cost effectiveness calculations.

recommended O&M procedures (or other industry-accepted standards) and (2) provide adequate recordkeeping to ensure the procedures are being implemented.

6.5 SAGUARO POWER COMPANY, HENDERSON

6.5.1 Background

Saguaro Power Company (SPC) (Source ID: 393) is an electric power generating facility (SIC code 4931, NAICS code 221112) that consists of two natural gas-/oil-fired CCTs (GE PG6541), each equipped with two 25 MMBtu/hr duct burners, two diesel starter engines, two natural gas-fired auxiliary boilers, and a cooling tower.

SPC is a major stationary source for NO_x and a minor source for all other pollutants. SPC operates according to the conditions contained in the Title V OP issued by DAQ. Since the 40 CFR Part 70 major-source classification is the same as the moderate attainment area major-source classification, RACT is required only if the permitted PTE for either VOC or NO_x exceeds the Part 70 major source threshold. According to the source PTE summary contained in the facility's current Title V OP, the facility's NO_x PTE is 163.77 tpy and its VOC PTE is 13.36 tpy. For the turbines, the NO_x PTE is 69.24 tpy and the VOC PTE is 4.29 tpy. Both limits include duct burner operation. The PTE for Auxiliary Boiler #1 is 13.94 tpy for NO_x and 4.47 tpy for VOC. The PTE for Auxiliary Boiler #2 is 9.33 tpy for NO_x and 0.15 tpy for VOC. The PTE for both NO_x and VOC for each diesel starter engine is below 5 tpy.

Based on DAQ's RACT applicability guidelines, SPC is subject to RACT for NO_x for both turbines and the auxiliary boilers. NO_x and VOC emissions for all other sources are below the RACT applicability threshold (5 tpy). Table 6.5-1 provides a summary of the affected units, current control equipment, and NO_x and VOC emission limits.

Table 6.5-1. SPC RACT-Affected Units

Emission Unit	Description	Date of Commercial Operation	Control(s)	Emission Limits	
				NO_x	VOC
A01 (Unit 1)	Combustion Turbine Generator #1 (35 MW) with two fired HRSG (F05/05a)	1991	Steam Injection / SCR	Natural Gas: 15.20 lb/hr 10 ppm @ 15% O_2 (includes duct burners)	Natural Gas: 0.92 lb/hr
A02 (Unit 2)	Combustion Turbine Generator #2 (35 MW) with two fired HRSG (F06/06a)	1991			
F05	Supplemental Duct Burner (25 MMBtu/hr), Skid #1	1991			
F05a	Supplemental Duct Burner (25 MMBtu/hr), Skid #1	1991			
F06	Supplemental Duct Burner (25 MMBtu/hr), Skid #2	1991			
F06a	Supplemental Duct Burner (25 MMBtu/hr), Skid #2	1991			
A05 (Unit 5)	Auxiliary Boiler #1 (natural gas/hydrogen-fired, 218 MMBtu/hr)	1997	LNB / FGR / OC	13.94 tpy 3.18 lb/hr 12 ppm @ 3% O_2	4.47 tpy 1.02 lb/hr
A06 (Unit 6)	Auxiliary Boiler #2 (natural gas-fired, 86 MMBtu/hr)	1991	LNB	9.33 tpy 3.11 lb/hr 30 ppm @ 3% O_2	0.15 tpy 0.05 lb/hr

6.5.2 NO_x RACT Analysis

The following RACT analysis for NO_x was conducted using data and information in the RACT analysis provided by SPC,[248] as noted and where applicable.

6.5.2.1 Baseline Emissions

Baseline emissions establish the basis for the cost-effectiveness of each control option. Because Units 1 and 2 are identical units with similar dispatch, the baseline emissions were selected as the highest two-year average in the 2017–2021 period for a single unit.[249] Actual emissions data were used to determine the cost-effectiveness for all units because total emissions for the facility were well below 70% of PTE.

[248] Appendix 8

[249] Data provided by SPC for 2019-2021 by SPC. DAQ estimated 2017-2018 based on average NO_X emissions for 2019-2021 multiplied by the ratio of fuel usage as reported to EPA Mandatory Greenhouse Gas Reporting Program. The highest two-year average NO_X emissions for Units 1 and 2 is 54.60 tpy (Unit 27 - 2020-2021).

6.5.2.2 Combined Cycle Units (Units 1 and 2)

The analysis for the CCUs is based on natural gas combustion only. Both units were previously permitted to burn #2 oil in the event of natural gas curtailment. However, the plant does not currently have the capability to burn oil in either unit because the fuel oil storage tanks have been repurposed. The operating permit was revised on September 18, 2023 to remove the option of #2 oil as a fuel. If SPC elects to burn oil in the future, the facility must submit a revised RACT evaluation.

6.5.2.2.1 Control Equipment Evaluation

Table 6.5-2 shows the potential control technologies considered for each unit. These technologies are consistent with the potential retrofit options identified in EPA guidance for combustion turbines.[250] Certain technologies were not considered technically feasible so were eliminated from consideration, as discussed below.

Table 6.5-2. Technical Feasibility of NO_X Control Technologies (SPC)

Control Technology	Units 1 and 2
DLNC (with existing SCR)	Yes
SCR	Already equipped
SCR catalyst replacement	Yes
Steam injection	Already equipped
GCP	Yes

The installation of DLNC is considered a feasible option for both units, although it would require the elimination of steam injection, which cannot be used simultaneously with DNLC. SPC included an SCR catalyst replacement option in their analysis. Details on the scope of this option are limited; the ability to meet the proposed emission limit (6 ppm @ 15% O_2 or lower) cannot be determined without further investigation. SPC included an additional ammonia cost component in the annual operating cost evaluation, which suggests that the replacement may include a new catalyst or catalyst bed design that allows higher levels of ammonia injection. DAQ considers this option technically feasible based on this assumption. DAQ used the cost and performance estimates provided by SPC, although further investigation may be required.

6.5.2.2.2 Control Equipment Costs

All control equipment costs are based on vendor estimates provided by SPC[251] except as noted below. Estimates have been modified as follows to provide consistency between RACT determinations for the various units:

- TCI includes initial capital investment (equipment cost only) and direct costs (direct installation cost only).

[250] *Alternative Control Techniques Document – NO_X Emissions from Stationary Gas Turbines*, EPA, January 1993.
[251] Appendix 8

- Annualized TCI for DLNC is based on CoST.[252]
- Annualized TCI for the catalyst replacement assumes a five-year catalyst replacement cycle.

Potential energy impacts for certain upgrade options and several of the cost components described in the *EPA Air Pollution Control Cost Manual* were not included in order to simplify the analysis.[253] Estimated costs are thus considered conservative and likely understate actual costs associated with each control option (Appendix 9).

6.5.2.2.3 Control Equipment Performance

The achievable emissions level for the DLNC retrofit is based on the lowest RBLC determination for a similarly equipped unit (2 ppm @ 15% O_2).[254] The achievable emissions level for the SCR catalyst replacement is based on the highest RBLC determination for a similarly equipped unit (3 ppm @ 15% O_2).[255] DAQ assumed the highest level of emissions in this case to account for the uncertainty in the scope and performance of the catalyst replacement project.

6.5.2.2.4 Disbenefits

SCR. SCR converts NO_x to nitrogen and oxygen by reacting the NO_x compounds with ammonia in the presence of a catalyst. However, ammonia slip is required to account for non-uniform distribution of gases across the catalyst bed. The amount of slip required to maintain NO_x removal efficiency also increases over time due to catalyst deactivation. Because ammonia is a contributor to atmospheric fine particle formation, excess ammonia presents an adverse environmental impact. Other environmental concerns include accidental release of stored ammonia and disposal of spent catalyst, which may contain vanadium and/or titanium. SCR also presents an adverse energy impact, since the increased pressure drop across the catalyst bed reduces turbine efficiency.

DLNC. Maximum reduction in NO_x is typically achievable only at higher load conditions with premixed operation (< 75% load). A significant lack of turn-down capability may be an issue for peaking units or units with variable demand. In addition, decreasing the firing temperature may increase CO and VOC emissions.

DLNC have lower combustion efficiency than conventional combustors, which adversely affects fuel efficiency for these units. The source would have to purchase additional generating capacity

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[252] EPA *CoST* Version 4.1 Software (11/2022), https://www.cmascenter.org/cost/

[253] SPC also included annual remote tuning costs in their DLNC evaluation. DAQ excluded this cost from the evaluation for consistency with other DLNC evaluations.

[254] RBLC determinations for NO_X for the period 2012 – 2022 for CCUs equipped with SCR/LNB range from 2 - 3 ppm@15% O_2 (see Appendix 10) This is lower than the estimated level of performance (4 ppm@15% O_2) provided in the SPC RACT Analysis. Further investigation would be required to determine if this level of performance can be achieved as a retrofit on these units.

[255] RBLC determinations for NO_X for the period 2012 – 2022 for CCUs equipped with SCR (with and without water/steam injection) range from 2 - 3 ppm@15% O_2 (see Appendix 10). This is lower than the estimated level of performance (6 ppm@15% O_2) provided in the SPC RACT Analysis. Further investigation would be required to determine if this level of performance can be achieved as a retrofit on these units.

elsewhere to maintain total system generating capacity. Units equipped with water or steam injection would incur an energy penalty due to the loss of power augmentation.

6.5.2.2.5 RACT Determination

Table 6.5-3 lists the incremental control efficiency, achievable level of emissions, and cost-effectiveness of each control option used in the RACT determination for each unit. Additional supporting calculations can be found in Appendix 9.

Table 6.5-3. NO_x RACT Summary (SPC CCUs)

Control Equipment	Incremental Control Efficiency (%)	Achievable Emissions (ppm @ 15% O_2)	Cost Effectiveness ($/ton)
Units 1 and 2			
DLNC (with existing SCR)	80%	2	9,650
SCR catalyst replacement	70%	3	9,360
SCR/steam injection (existing controls)	N/A	10	N/A

Table 6.5-4 summarizes the RACT determination for each unit.

Table 6.5-4. Proposed RACT-Based NO_x Emission Limitations (SPC CCUs)

Emission unit	Emission Limitation/Work Practice		Monitoring Requirements
	Normal Operation	Startup/Shutdown	
Units 1 & 2	10 ppm @ 15% O_2 (four-hour average)	Follow good combustion practices	CEMS (follow existing permit requirements)

DAQ determines that the existing NO_x limit of 10 ppmvd @ 15% O_2 (4-hr average) while firing natural gas (excluding startup, shutdown, and malfunction) represents RACT based on the use of existing NO_x controls. All other technically feasible control options were eliminated due to excessive cost (> $9,400/ton for both units). Compliance will be demonstrated using CEMS according to the monitoring and reporting procedures in the source's current Title V OP. RACT during startup, shutdown, and other non-normal operation is determined to be adherence to GCP during each of those modes of operation; emissions are considered too variable to establish an emissions limit, so the work practice standard of GCP is RACT.

Since the current permit does not adequately reflect the monitoring, recordkeeping, and reporting requirements needed to ensure compliance with GCP, the permit will need to be revised to require that the permittee (1) develop a best operating practices document that includes manufacturer's recommended O&M procedures (or other industry-accepted standards) and (2) provide adequate recordkeeping to ensure these procedures are being implemented.

6.5.2.3 Auxiliary Boiler (Unit 5)

Unit 5 is an Indeck/Volcano (Model O-7-2000) watertube package boiler with a heat input rating of 218 MMBtu/hr. This boiler provides backup steam to nearby chemical manufacturing and food processing plants when the primary steam supply is offline. The boiler is permitted to fire natural gas and hydrogen from a nearby processing plant. Annual heat input is limited to 1,909,680 MMBtu/year. The hydrogen supply is variable, so the boiler must continuously adjust natural gas flow to maintain firing rate. The boiler was retrofit in 2014 with a Cleaver Brooks Natcom LNB with FGR and an OC system as part of the plant's cogeneration project to meet a NO_x emission limit of 12 ppm @ 3% O_2 and LAER CO emission limit of 1.2 ppm @ 3% O_2 while firing natural gas.

6.5.2.3.1 Control Equipment Evaluation

Section 4 provides an extensive list of potential boiler NO_x control technologies. These technologies can be generally classified as combustion or post-combustion controls. Most of the available control technologies are combustion controls that reduce NO_x formation using a variety of methods to optimize combustion air and/or improve fuel/air mixing. While NO_x reduction is the primary goal of these technologies, their implementation typically reduces combustion efficiency, which can cause increases of CO and VOC emissions. In this case, even minor increases in CO may cause Unit 5 to exceed the LAER CO emission limit, depending on the ability of the OC system to offset additional CO formation. Further evaluation is required to determine which technology may be technically feasible.

Two additional combustion-related control technologies were considered but deemed to be technically infeasible: installation of CFB and BOOS operation. However, the installation of CFB is not commercially available for a watertube boiler of this size,[256] and BOOS requires multiple burners but Unit 5 is equipped with only a single burner.

DAQ also considered the installation of SCR and SNCR on this boiler. However, the exhaust temperature (~325°F) is below the minimum temperature required for either technology.

Table 6.5-5 lists the technical feasibility of NO_x control technologies for SPC Unit 5, including whether it's possible to implement the technology and whether it's already equipped with the technology.

[256] Appendix 8a – Saguaro RACT Analysis- DAQ Supporting Documentation

Table 6.5-5. Technical Feasibility of NO_X Control Technologies (SPC Unit 5)

Control Technology	Unit 5
SNCR	No
SCR	No
CFB	No
BOOS	No
Other Combustion-Related Controls: • LNB upgrade • SCA • EAR / LEA • GFM	Possibly. Technical feasibility would require further evaluation of additional CO formation associated with each control technology and capabilities of existing CO OC system.
FGR	Already equipped
LNB	Already equipped
GCP	Already implemented

6.5.2.3.2 RACT Determination

DAQ was unable to identify any technically feasible upgrade operations without further analysis of combustion-related modifications and their effects on CO emissions. Although additional modifications may be possible, none of the technologies would be considered cost-effective due to the boiler's limited operation.[257]

DAQ concludes that the existing NO_x emission limit of 12 ppmvd @ 3% O_2 (4-hr average) while firing natural gas (excluding startup and shutdown operation) represents RACT based on the use of existing controls. Compliance shall be demonstrated using CEMS according to the current monitoring, recordkeeping, and reporting procedures in the source's current OP. RACT during startup, shutdown, and other non-normal operation is determined to be adherence to GCP during each of those modes of operation; emissions are considered too variable to establish an emissions limit, so the work practice standard of GCP is RACT. While the source is already required to follow good combustion practices and maintain the boiler in accordance with the manufacturer's O&M manual,[258] the permittee shall ensure these procedures also address periods of startup, shutdown, and other non-normal operation.

Table 6.5-6 lists the proposed RACT-based NO_x emission limit for Unit 5 during normal and startup/shutdown modes of operation, and the corresponding monitoring requirements.

[257] Assuming a best-case scenario where the retrofit results in RACT-level NO_X emissions of 8.2 ppm @ 3% O_2 (based on lowest RBLC determination for combustion-related upgrades), the estimated total capital investment cost would need to be less than $6,500 in order for the retrofit to be considered cost effective based on the cost effectiveness threshold ($5,500/ton). There are no available technologies that can achieve such reductions for that cost (see Appendix 9).
[258] Condition E(1)(l) of Title V OP.

Table 6.5-6. Proposed RACT-Based NO_x Emission Limitations (SPC Unit 5)

Emission unit	Emission Limitation/Work Practice		Monitoring Requirements
	Normal Operation	Startup/Shutdown	
Unit 5	12 ppm @ 3% O_2 (4-hr average)	GCP	CEMS (follow existing permit requirements)

6.5.2.4 Auxiliary Boiler (Unit 6)

Unit 6 is a Nebraska watertube package boiler (Model NOS 2A/S-55) with a heat input rating of 86 MMBtu/hr. This boiler provides steam to the nearby Ocean Spray® manufacturing facility. The boiler is permitted to fire natural gas with an annual heat input limitation of 510,000 MMBtu/year and an annual operating limit of 6,000 hours in any consecutive 12 months. The unit is currently equipped with an LNB designed to meet a NO_x emission limit of 30 ppm @ 3% O_2.

6.5.2.4.1 Control Equipment Evaluation

The Unit 6 control equipment evaluation is based on the potential NO_x control technologies for boilers described in Section 4 of this report. Table 6.5-7 lists control technologies and an assessment of the technical feasibility of each.

Table 6.5-7. Technical Feasibility of NO_x Control Technologies (SPC Unit 6)

Control Technology	Technical Feasibility	Comments
SNCR	No	Boiler exhaust temperature is lower than required (500–200°F).
SCR	No	Boiler exhaust temperature is lower than required (1,400–1,600°F).
LNB Upgrade / FGR	Yes	
EAR / LEA	No	Boiler is already equipped with LNB and the plant conducts routine boiler tuning to optimize excess air flow.
ARA	No	Boiler is not currently equipped with OFA.
CFB / RCB	Yes	
GFFM	No	A literature search did not find articles or reports on the use of gas fuel flow modifiers on a gas-fired package boiler equipped with LNB. Since Unit 6 is already equipped with LNB, which incorporates air-fuel mixing strategies, this option likely will have little or no effect in reducing emissions.
WSI	No	A literature search did not find articles or reports suggesting addition of water or steam injection to boilers already equipped with LNB is technically feasible.
OFA	No	Unit 6 is a relatively small boiler that likely does not provide sufficient space to benefit from the use of OFA.[259]

[259] *NO_x Emissions Control from Stationary Sources Student Manual*, p. 6-10: "Overfire air combustion modifications require the penetration of the boiler wall by new air ducts and usually requires changes to the air handling system in order to deliver the air to the secondary combustion zone. Furthermore, there must be sufficient space above the burners and before the heat exchange area of the boiler to provide sufficient time for the combustion reactions. Because of this limitation, this approach is not possible on some existing coal-, oil-, and gas-fired suspension-type boilers." 2009. PLAN361-CI (formerly APTI Course 418), EPA.

Control Technology	Technical Feasibility	Comments
FIR	Possibly	FIR burners are commercially available for packaged watertube boilers from John Zink/Coen. For this evaluation, DAQ assumed that a FIR burner retrofit is technically feasible, although further investigation is required to confirm.
FIR2	Possibly	FIR2 has been demonstrated commercially in an industrial boiler, achieving NO_x emissions of 17 ppm, although this study is dated.[260] A literature search did not find articles or reports on this study, or any information suggesting FIR2 is a technically feasible retrofit option for this boiler, or whether this technology is even still commercially available. For this evaluation, DAQ assumed that FIR2 is technically feasible, but further investigation is required to confirm.
BT / OT	Already implemented	SPC required to conduct semiannual boiler inspections and tune-ups.[261]
NGR	No	NGR for industrial boilers has previously been limited to some coal- and municipal solid waste-fired boilers.[262] A literature search did not find articles or reports on NGR use in natural gas-fired, packaged watertube boilers, so this technology is not considered technically feasible.
CCB	No	CCB is considered an inferior technology compared with other LNBs. Available performance data shows NO_x emissions were reduced from 70 ppm to less than 20 ppm with a 5% boiler efficiency loss due to the injection of steam into the combustion zone; other LNB can achieve 9–10 ppm without using steam injection.
BOOS	No	This approach requires multiple burners. Unit 6 is equipped with only a single burner.
FGR	Possibly	DAQ will consider adding FGR to the existing LNB, although further investigation would be required to determine whether the existing burner would support it. DAQ will also consider replacing the existing LNB with a newer design that incorporates FGR.
GCP	Already implemented	SPC is required to conduct semiannual boiler inspections and tune-ups, and to follow manufacturer's O&M manual for GCP.[263]

6.5.2.4.2 Control Equipment Costs

Table 6.5-8 provides a summary of the cost assumptions associated with each technically feasible upgrade option. Control equipment costs include the following general assumptions:

- TCI includes initial capital investment (equipment cost only) and direct costs (direct installation cost only).
- Annualized TCI for all control operations is based on an estimated equipment life of 15 years (except as noted).[264]
- Interest rate used for calculating annualized TCI is based on DAQ RACT guidelines.

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[260] "Alternative Control Techniques Document–NO_X Emissions from Industrial/Commercial/Institutional (ICI) Boilers," March 1994. EPA-453/R-94-022.
[261] Condition F(3)(g) of Title V OP.
[262] *Guide to Low Emission Boiler and Combustion Equipment Selection*, April 2002. ORNL/TM-2002/19.
[263] Condition F(3)(g) of Title V OP.
[264] Estimated equipment life for combustion-related upgrades = 15 years based on CoST version 4.1.

Cost estimates for certain options are based on vendor estimates provided by SPC. These estimates have been modified to reflect DAQ's cost assumptions for consistency with other RACT analyses. Potential energy impacts for certain upgrade options and several of the cost components described in the *EPA Air Pollution Control Cost Manual* were not included to simplify the analysis. Estimated costs are considered conservative and likely understate actual costs associated with each control option (Appendix 9).

Table 6.5-8. Control Equipment Costs (SPC Unit 6)

Control Technology	Comments
LNB Upgrade / FGR	Cost of LNB upgrade with FGR based on vendor estimate for ultra-low NO_x burner utilizing metal-fiber, surface-stabilized combustion technology.[265]
CFB	Capital cost ($0.78/1000 Btu (2011$)) based on a white paper.[266] In calculating annualized TCI, DAQ assumed a 10-year equipment life, which is shorter than other combustion options because the CFB are easily damaged.
FIR	Cost information was not readily available for FIR burner retrofit. DAQ assumed costs are similar to LNB replacement without FGR based on vendor estimate for LNB+FGR modified to reflect LNB replacement only.[267]
FIR2	Cost information was not readily available for FIR2 retrofit. DAQ assumed cost is the same as for an FGR retrofit with no burner replacement.
FGR	Cost of adding FGR to existing burner based on vendor estimate for LNB+FGR modified to reflect FGR only.[268]

6.5.2.4.3 Control Equipment Performance

Table 6.5-9 lists the assumptions used to determine the achievable emissions level for each of the technically feasible upgrade options. To the extent possible, DAQ applied the same performance assumptions used in the other boiler RACT analyses in this report.

Table 6.5-9. Control Equipment Performance (SPC Unit 6)

Control Technology	Comments
LNB Upgrade / FGR	Achievable emissions level of 5 ppm @ 3% O_2 based on vendor performance guarantee.[269]
CFB	Achievable emissions level of 15 ppm @ 3% O_2 based on vendor white paper.[270]
FIR	FIR vendor literature states that burners are capable of reaching single-digit NO_x concentrations and that performance is similar to LNB equipped with FGR. DAQ assumed an achievable emissions level of 9 ppm @ 3% O_2 based on vendor performance guarantee for LNB upgrade option with FGR.
FIR2	Limited information was available for NO_x control efficiency using FIR2. DAQ assumed a 58% incremental removal efficiency (13 ppm @ 3% O_2) based on the average removal

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265 Estimate provided was for a 35 MMBtu/hr fire-tube boiler burner that was modified based on the Unit 6 heat input rating. The cost estimate was based on a burner without FGR and, therefore, is considered conservative (see Appendix 8a).

266 *Characterizing Costs, Savings, and Benefits of a Selection of Energy Efficient Emerging Technologies in the United States*, Xu, T., Lawrence Berkeley National Laboratory, 3/31/2011.

267 Appendix 9

268 Appendix 9

269 Appendix 8a

270 *Radiant Fiber Burners for Gas-Fired Appliances and Equipment*, John P. Kesselring, Robert M. Kendall, and Richard J. Schreiber, Alzeta Corporation.

Control Technology	Comments
	efficiency demonstrated in a utility boiler study.[271]
FGR	The achievable emissions level for the addition of FGR to the existing LNB is estimated to be 15 ppm @ 3% O_2. This assumes an incremental reduction of 50% from baseline emissions based on upper range of expected performance from other installations (i.e., 40–50% using 20–30% FGR).[272]

6.5.2.4.4 RACT Determination

Table 6.5-10 lists the incremental control efficiency, achievable level of emissions, and cost-effectiveness of each control option used in the RACT determination for Unit 6. Additional supporting calculations are in Appendix 9.

Table 6.5-10. NO_X RACT Summary (SPC Unit 6)

Control Equipment	Incremental Control Efficiency (%)	Achievable Emissions (ppm @ 3% O_2)	Cost Effectiveness ($/ton)
LNB Upgrade/FGR	83%	5	34,300
FIR	70%	9	53,700
FIR2	58%	13	19,200
CFB	50%	15	18,500
FGR	50%	19	15,400
LNB (existing controls)	N/A	30	N/A

Table 6.5-11 summarizes the RACT determination for Unit 6. DAQ determines that the existing NO_x limit of 30 ppmvd @ 3% O_2 (excluding startup and shutdown operation) represents RACT based on the use of existing NO_x controls. All other technically feasible control options were eliminated due to excessive cost ($15,400–$53,700/ton). Compliance will be demonstrated by following the existing monitoring and recordkeeping requirements and operating restrictions in the current Title V OP. RACT during startup, shutdown, and other non-normal operation is determined to be adherence to GCP during each of those modes of operation; emissions are considered too variable to establish an emissions limit, so the work practice standard of GCP is RACT. While the source is already required to follow good combustion practices and maintain the boiler in accordance with the manufacturer's O&M manual,[273] the permittee shall ensure these procedures also address periods of startup, shutdown, and other non-normal operation.

Table 6.5-11. Proposed RACT-Based NO_X Emission Limitations (SPC Unit 6)

Emission Unit	Emission Limitation/Work Practice		Monitoring Requirements
	Normal Operation	Startup/Shutdown	
Unit 6	30 ppmvd @ 3% O2	Follow good combustion practices	Follow existing permit conditions

[271] *Demonstration of Fuel Injection Recirculation (FIR) for NO_X Emissions Control*, Reese, James L., et al., 1994.

[272] APTI 418, Control of Nitrogen Oxides Emissions, p. 6-18. 2000.

[273] See Condition E(1)(l) of the current Title V operating permit.

Appendix 1

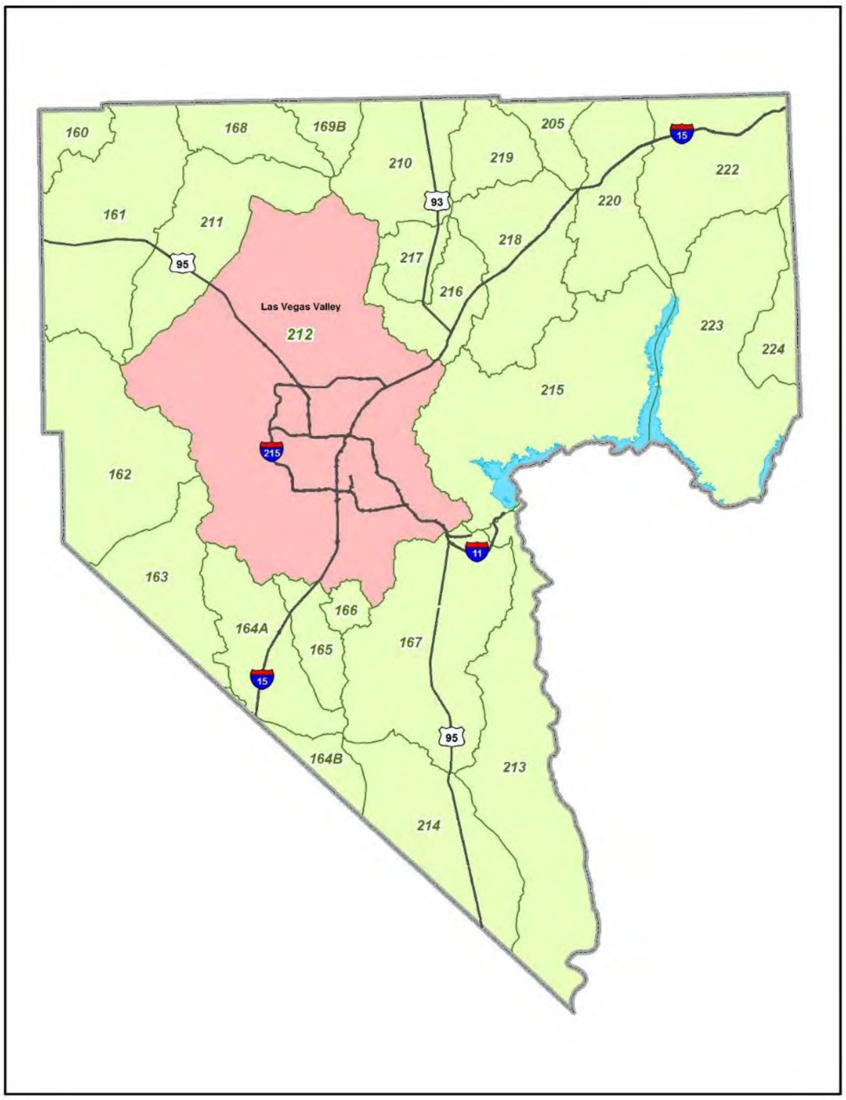
Final RACT Methodology for
HA 212 2015 8-hour Ozone NAAQS

FINAL RACT METHODOLOGY FOR HA 212 2015 8-HOUR OZONE NAAQS

I. INTRODUCTION

On June 4, 2018, EPA designated a portion of Clark County (hydrographic area 212) as a marginal nonattainment for the 2015 8-hour ozone National Ambient Air Quality Standards (NAAQS) based on a design value that exceeded the 0.07 ppm NAAQS. (83 FR 25776). HA 212 is located in a central location within Clark County and includes the Las Vegas Valley. *See* Figure 1.

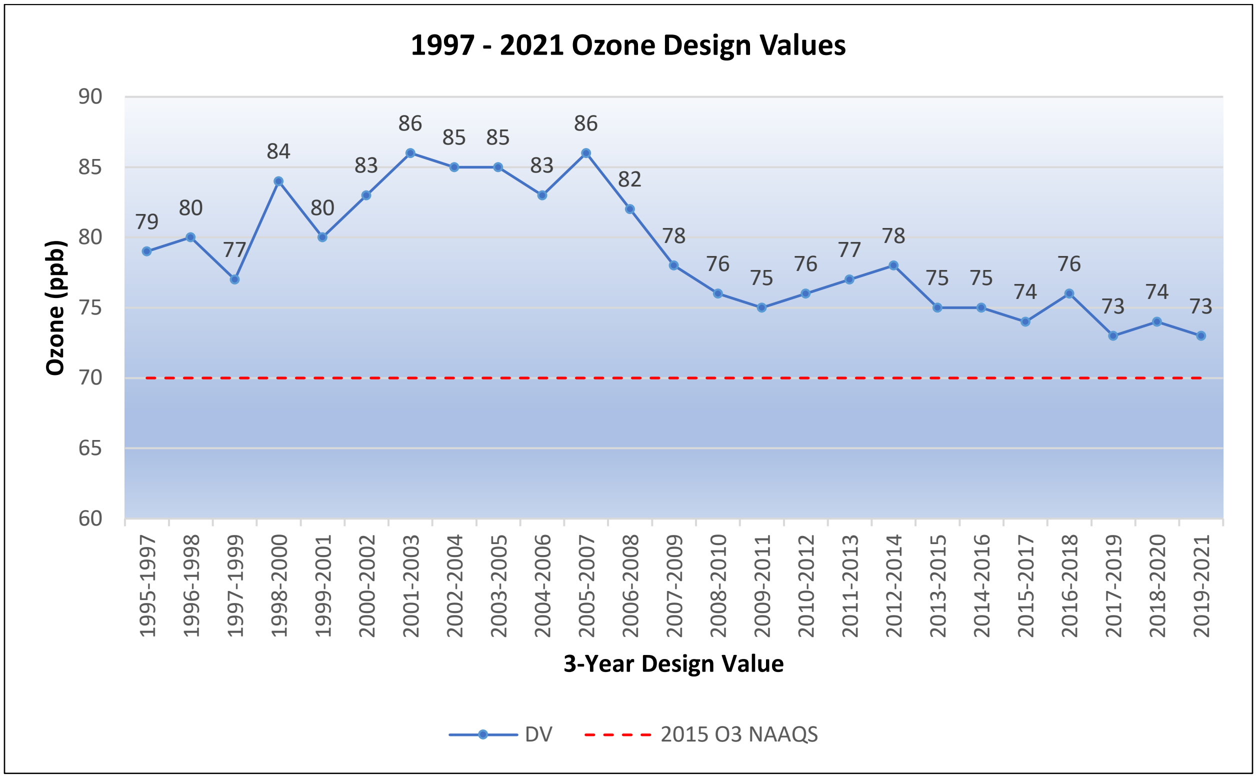
Figure 1. Nonattainment Area (Hydrographic Area 212) in Clark County, Nevada



II. OZONE IN CLARK COUNTY

The predominant source of NOx emissions in Clark County are from on-road mobile sources, while the predominant source of VOC emissions are biogenic. Point Sources of both NOx and VOC emissions comprise a very small portion of the total emissions inventory. In 2017, NO_x point sources contributed 1033 tons to the NO_x emissions inventory, while VOC point sources contributed a total of 447 tons to the VOC emissions inventory. Of these total point source emissions, NOx major sources represent only one third of the total inventory, while the VOC major sources comprise less than five percent (5%). During a typical summer day in 2017, NO_x major stationary sources collectively emitted less than 1 ton of NO_x, while VOCs major sources are below a tenth of a ton. This means that there may be fewer opportunities to implement cost-effective emissions controls on major sources.

Figure 2 – Ozone Trends in Clark County HA 212



III. ATTAINMENT DATE REQUIREMENTS

The effective date of the nonattainment designation for HA 212 occurred on August 3, 2018. EPA's implementation rule for the 2015 ozone NAAQS (40 CFR Part 51, Subpart CC) provides that a marginal nonattainment area must achieve attainment within three (3) years of the effective date of the nonattainment designation. Accordingly, HA 212's was required to achieve attainment of the 2015 8-hour Ozone NAAQS by August 3, 2021.

Whether HA 212 achieved attainment by this date is based on the 2018-2020 design value. DAQ identified 28 exceedance days at area monitors during this period that were likely caused by exceptional events such as wildfires or stratospheric ozone intrusions. In accordance with EPA's exceptional events rule (40 CFR 40 CFR §50.14), DAQ submitted 17 exceptional event demonstrations that included data, modeling, and other information to U.S. Environmental Protection Agency (EPA) Region 9 to support excluding monitoring data for these 28 event days from calculation of HA 212's ozone design value for the 2018-2020 ozone seasons.

After reviewing the data, Region 9 found that the weight of evidence did not support a finding that emissions from exceptional events caused exceedances of the ozone NAAQS in HA 212 on June 19-20, 2018, May 6, 2020, May 9, 2020, June 22, 2020, and June 26, 2020. Region 9 deferred reviewing the request for excluding monitoring data for other requested dates, because the Region determined that a finding on those dates would not affect a decision on HA 212's attainment status or qualification for a one-year extension for demonstrating attainment. Without excluding monitoring data for these dates from the design value calculation, HA 212's 2018-2020 design value equals 0.074 ppm. This value is above the 0.07 ppm design value required to demonstrate attainment of the 2015 8-hour ozone NAAQS (as required by 40 CFR §50.19) by HA 212's attainment date.

Under CAA Section 181(b), the EPA generally is required to reclassify a nonattainment area to the next higher ozone classification if the ozone nonattainment area fails to meet its attainment date. Thus, DAQ expects EPA to reclassify HA 212 from a marginal to a moderate nonattainment area for the 2015 8-hour ozone NAAQS (if EPA finalizes Region 9's nonoccurrence on DAQ's request to exclude certain dates of monitoring data from the 2018-2020 ozone design value calculation).

This redesignation will trigger additional state implementation plan (SIP) requirements for HA 212, including a requirement to impose reasonably available control technology requirements on certain stationary sources.

IV. RACT UNDER EXISTING DAQ REGULATIONS VS. NONATTAINMENT AREA RACT

DAQ's rules already require stationary sources to comply with RACT under Sections 12.1.3.6 and 12.4.3 of the permitting rules. DAQ defines RACT in Section 12.0 as

> the lowest emissions limitation that a particular source is capable of meeting by the application of control technology that is reasonably available, considering technological and economical feasibility...

This RACT requirement applies when a stationary source proposes to construct or modify an emissions unit and increase potential emissions at a minor stationary source by greater than significant and at a major stationary source by greater than the minor NSR Significant Level for a pollutant. For NO_x and VOC emissions increase, the significance levels are 20 tpy. (*See* Sections 12.1.1 and 12.4.2.1).

Although the DAQ's and EPA's definitions for "RACT" are consistent [1], the applicability of RACT to stationary sources under DAQ's current rules differs from the required applicability for RACT based on an area's nonattainment classification. The requirements for nonattainment areas are in Part D of the Clean Air Act. Section 172(c)(1) of Part D requires a nonattainment area to adopt reasonably available control measures including reasonably available control technology requirements for stationary sources.

CAA Section 182(b) adds additional information on meeting RACT requirements for moderate ozone nonattainment areas. Under Section 182, a moderate nonattainment area must apply RACT for VOC emissions to each source category for which EPA issued a control technology guideline (CTG). CTGs provide the "presumptive norm" for minimum VOC control requirements for specific categories of sources.[2] Sources falling into a source category for which EPA has published a CTG are referred to as "CTG sources." EPA recommends that air pollution control agencies adopt regulations that are consistent with the applicability thresholds and control level in these CTGs. Air pollution control agencies may, however, "judge the feasibility of imposing the recommended controls on particular sources, and adjust the controls accordingly."[3]

EPA has not issued CTGs for NO_x emissions from source categories, thus no RACT requirements apply to NO_x source categories by virtue of an EPA issued CTG. Instead, EPA issues Alternative Control Techniques (ACT) guidance for NO_x source categories. These guidance documents do not establish a presumptive level of emissions control, rather the documents provide information on potential control measures and costs. They provide a resource for determining RACT for individual major sources and for Reasonably Available Control Measure (RACM) requirements.

CAA Section 182(b)(1)(A)(ii)(II) also requires RACT for all major sources of ozone precursors, and Section 182(f) extends this major source requirement to NOx major sources. For a moderate nonattainment area such as HA 212, "major source" is defined as a stationary source that emits, or has the potential to emit at least 100 tons per year of either VOC or NO_x.

EPA codified these requirements for the 2015 ozone National Ambient Air Quality Standard (NAAQS) in its Ozone Implementation Rule found in 40 CFR Part 51, Subpart CC.[4]

The following outlines DAQ's process for satisfying CAA Sections 172(c)'s and 182(b)'s RACT requirements for CTG Sources and VOC and NOx major sources.

[1] Neither the CAA nor EPA's rules contain a codified definition of reasonably available control technology for purposes of implementing the CAA Part D RACT requirements. Instead, EPA has defined RACT in numerous guidance statements as "the lowest emissions limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." EPA first set forth this definition in Memorandum from Roger Strelow, Assistant Administrator for Air and Waste Management to Regional Administrators, "Guidance for Determining Acceptability of SIP Regulations in Non-attainment Areas," (Dec. 9, 1976).

[2] 44 *Fed. Reg.* 53761 (Sept. 17, 1979)
[3] *Id.*
[4] 88 *Fed. Reg.* 62998 (

V. PROCESS FOR CTG SOURCES

Step 1 – Identify RACT CTG Sources

Attachment 2 includes a list of EPA's current VOC CTG source categories. DAQ will determine whether any stationary source within the source category is operating in the Clark County nonattainment area. DAQ will employ several search methods to identify whether CTG sources operate within the nonattainment area. These search methods may include, but are not necessarily limited to:

1. Review national emissions inventory information
2. Perform internet search using key terms from source category
3. Consult permitting and enforcement staff
4. Search business licenses issued through the Secretary of State
5. Public Outreach

Step 2 – Compare existing emission control requirements to CTG presumptive norm.

For each VOC CTG source category with an operating source in the HA 212 nonattainment area, DAQ will review EPA's CTG for that source category. Then, DAQ will review permits for the stationary source(s) and applicable Federal and SIP regulations to determine whether the permit or regulations already require a level of VOC emissions reduction consistent with EPA's presumptive norm for the CTG source category. As explained above, under DAQ's SIP-approved permitting program, sources may be subject to a VOC RACT requirement under Section 12.1.3.6 and 12.4.3 of DAQ's rules. In addition, CTG sources may be subject to VOC BACT or LAER requirements imposed under the requirements of Section 12.2 or 12.3, or a State SIP requirement or federal emissions standards such as New Source Performance Standards and National Emissions Standards for Hazardous Air Pollutants.

If a CTG source is subject to a RACT, BACT or LAER or federal or SIP requirement, DAQ will evaluate the required control level to determine if the control level satisfies EPA's presumptive norm for the source category. DAQ anticipates that one of four findings may result from this evaluation:

1. There is no operating CTG sources in a source category in the HA 212 nonattainment area;
2. CTG Source is subject to a RACT, BACT, LAER or federal or SIP requirements that is consistent with the emissions reduction achievable through application of the presumptive norm;
3. CTG Source is subject to RACT, BACT, LAER or federal or SIP requirement that is less stringent than the presumptive norm;
4. CTG Source is currently not subject to RACT, BACT, LAER or a federal or SIP rule.

Step 3 –Negative Declaration or Establish RACT

For any CTG source category for which DAQ fails to identify an operating source within the Clark County nonattainment area, DAQ will issue a negative declaration for the source category in its SIP submittal.

If the CTG source category currently is subject to a federal or SIP-approved regulation that is consistent with the emissions reductions that would be expected through application of EPA's presumptive norm, then DAQ will determine whether that rule is already part of the SIP. If that rule is not already adopted into the SIP, then DAQ will adopt the rule into the SIP to satisfy RACT requirements. In conducting this assessment, DAQ will also evaluate coverage of startup, shutdown, and malfunction (SSM) emissions under the existing rule. If the current rule includes an exemption for SSM emissions, then DAQ will consider separate regulations to establish RACT requirements for SSM emissions from the source category.

If a CTG source(s) is already subject to a permit-based, control requirement that is consistent with the presumptive norm, then DAQ will either submit the existing permits as a source-specific SIP requirement, or develop a SIP-approvable regulation specifying these applicable emission limitations for the CTG source through rule.

If one or more VOC CTG sources currently are subject to a permit or regulatory requirement, but the required VOC control level does not meet EPA's presumptive norm for the CTG source category, or if the CTG source(s) are not currently subject to VOC emissions control requirements, then DAQ will codify a regulation for that source category to satisfy VOC RACT requirements, or require a permit application submission for the CTG sources to establish case by case RACT in a permit. DAQ would likely use the permitting mechanism to establish RACT only if there are few CTG sources in a source category.

In establishing a categorical CTG source category regulation, or issuing a case-by-case RACT through issuance of a permit, DAQ will consider EPA's CTG for the source category as guidance for developing the RACT regulation, and also may consider regulations imposed by other states on the particular source category. DAQ envisions that any RACT requirement will be consistent with the applicability thresholds and control levels of the presumptive norm in the CTG unless DAQ finds that the presumptive norm is technically or economically infeasible for one or more CTG sources operating in the HA 212 nonattainment area.

VI. RACT FOR VOC AND NO_X MAJOR SOURCES RACT

As explained above, Section 182(b) requires DAQ to require RACT for all major stationary sources of VOC, and Section 182(f) requires DAQ to also apply RACT requirements to major stationary sources of NOx. EPA's guidance allows an air pollution control agency to establish a general RACT rule that applies to a category of stationary sources, or determine RACT for each emissions unit at a stationary source on a case-by-case basis. EPA also allows averaging between emissions units to demonstrate that, on whole, a RACT level of control is achieved by the emissions units. DAQ will consult with EPA before approving any averaging approach to satisfy BACT requirements.

Through a review of the 2017 National Emissions Inventory, DAQ preliminarily identified the following major sources that could be subject to the VOC or NOx RACT requirements. Table 1 identifies the major sources, and an inventory of emissions units for these major sources is contained in Attachment 1.

Table 1. Major Sources in HA 212 Nonattainment Areas

NOx Major Sources				
Facility ID	**Facility Name**	**Total Facility NOx PTE (tpy)**	**2017 NEI Emissions tpy**	**2017 NEI Emissions (tpd)**
7	Clark Generating Station	2465.9	115.40	0.32
114	Nellis AFB	199.0	19.81	0.05
257	Caesars Consolidated Properties	370.1	19.9	0.05
393	Saguaro Power Company	164.1	102.79	0.28
423	Sun Peak Generating Station	249.4	15.89	0.04
825	MGM Resorts International	767.1	65.07	0.18
16304	Switch, Ltd.	246.18	33.23	0.09
VOC Major Sources				
Facility ID	**Facility Name**	**Total Facility VOC PTE (tpy)**	**2017 NEI Emissions tpy**	**2017 NEI Emissions (tpd)**
13	Calnev Pipeline LLC	187.4	59.31	0.16
7	Clark Generating Station	216.5	14.12	0.04

Based on the limited number of major sources in HA 212's emissions inventory, DAQ believes that it is most appropriate to determine RACT for existing sources on a case-by-case basis for each major stationary source. DAQ does not believe it is necessary to determine RACT for all future new or replaced emissions units at this time. As explained above, DAQ rules already require RACT, BACT or LAER determinations for stationary sources that construct or modify above the minor NSR significant levels. Should a major source propose to construct a new VOC and NOx emissions unit above the RACT applicability threshold in the nonattainment area, then DAQ will request a RACT analysis with the construction permit application, and establish RACT requirements in the issued permit to the extent there are available emissions controls that are both technically and economically feasible.

Step 1 – Information Collection

As a first step in the case-by-case RACT process, DAQ will provide each major source the opportunity to submit a control technology analysis with a proposed RACT demonstration for its emissions units. Given the short period of time for DAQ to identify and implement RACT, it is important that DAQ focus both our major source resources and DAQ's resources on identifying opportunities for meaningful emissions reductions. To that end, DAQ advised major sources to submit RACT analysis information on each of their emissions units having a PTE equal to or greater than 5 tpy.

DAQ believes that 5 tpy represents an appropriate applicability threshold for evaluating potential RACT requirements and that excluding emissions units below this level from the information request represents a reasonable *de minimis* level. EPA allows states to establish a *de minimis* level for purposes of implementing RACT.[5]

A review of the individual emissions units located at our eight major sources (See Attachment 1) shows that applying this *de minimis* threshold would allow only small natural gas boilers (1-< 25 MMbtu/hr heat input); some emergency generators with actual emissions far below the emissions unit's PTE; and smaller emitting emissions units such as natural gas water heaters to avoid RACT applicability (0.01 tpy). The major contributors to each major source's actual emissions would be subject to the RACT review.

DAQ believes it is not cost-effective to regulate emissions from these smaller emissions units, because there are a lack of available, cost-effective control measures for these smaller emissions. The cost-effectiveness is further challenged by the reduced yearly emissions of the major source. As evident from the Table 1, the majority of major sources in HA 212 are emitting at orders of magnitude below the major source's PTE.

In addition, DAQ reviewed several existing State RACT requirements and found applicability thresholds for RACT requirements for industrial and commercial boilers, process heaters, and steam generators generally applied at greater than 50 mmBtu/hr heat input. San Diego County recently showed that applying lower applicability thresholds to these types of emissions units resulted in cost effectiveness values exceeding $12,000/ton. San Diego County, an area with air quality more impaired than HA 212, does not consider this cost per ton cost value cost-effective, and DAQ concurs in that finding.[6] DAQ believes that costs for major sources in HA 212 will be similar to those in San Diego County. Thus, we believe it will likely not be cost-effective to control emissions units with heat inputs lower than 50 mmBtu/hr. Nonetheless, we requested information and cost calculations at a value half of this amount. Likewise, we expect that emissions controls on smaller emergency generators, which operate infrequently, and water heaters that have negligible actual emissions would not be cost-effective.

Step 2 Information Needs

DAQ issued an invitation to major sources to submit information relative to a case-by-case RACT requirement. DAQ requested the following information:

1. Information sources relied on to identify available control options
2. Ranking of available control options based on control effectiveness
3. Evaluation of technical feasibility
4. Annual and incremental cost effectiveness ($/ton)
5. Baseline and controlled tpy emissions estimates (and basis)

[5] *See* Memorandum from G.T. Helms, Group Leader Ozone Policy and Strategies Group to Air Branch Chief, Region 1-X, "De Minimis Values for NOx RACT," (Jan. 1, 1995)
[6] "2020 Reasonably Available Control Technology Demonstration for the National Ambient Air Quality Standards for Ozone in San Dieago County," County of San Diego Air Pollution Control District (October 2020).

6. Environmental, energy and other impacts (benefits and disbenefits); GHG, HAP or other
7. pollutants
8. Proposed RACT emissions limitation or averaging approach
9. Schedule for installing and operating the emissions control
10. Proposed testing, monitoring, recordkeeping, and reporting meeting periodic or CAM monitoring requirements.

To assure uniformity in the cost estimates between major sources, DAQ asked major sources to submit cost information using a 6% interest rate and the remaining useful life of the emissions unit (assuming an original useful life of 30 years unless the major source submits information justifying a different useful life.) The major source may also provide information on actual interest rates available to the major source, and DAQ will consider this information in determining RACT for the major source.

DAQ advised major sources that the baseline emissions for the cost effectiveness calculations should be based on the emissions unit's potential to emit (PTE) including consideration of existing, enforceable control technologies. Alternatively, if either the major source, or a particular emissions unit's actual emissions over a representative period of operations are less than 70% of the PTE, then the major source can elect to provide cost effectiveness information based on use of actual emissions. Actual emissions may be used as a baseline for all emissions units if the major source's actual emissions are 70% below its potential to emit, or for individual emissions units if a particular emissions unit's actual emissions are 70% below that emission unit's PTE.

Step 3 Information Verification

After receiving information from major sources, DAQ will review the information for thoroughness and reliability. DAQ will then determine whether it agrees with the major source's RACT recommendation.

In determining the suitability of a given control option for RACT, DAQ will be guided by cost effectiveness values DAQ approved in past control technology determinations, cost effectiveness guidance provided by EPA, and cost thresholds found acceptable by other states.

Step 4 Establish RACT Requirements

Once DAQ determines the appropriate control measures that qualify as RACT, it will determine the RACT emissions limitation. If DAQ determines that no control measure is cost-effective because of a reduced life expectancy, then DAQ will consider requiring the emissions unit to shutdown by a date certain. DAQ will also consider whether any interim measures are available to reduce emissions before the mandated shutdown date.

The RACT emissions limitation will represent the lowest achievable emissions level with which the emissions unit(s) can continuously comply using the proposed RACT control option. The proposed emissions limitation will also include requirements for startup, shutdown and malfunction periods (SSM) (with a proposed definition of SSM to govern these operations). The SSM provisions may be included in a single RACT emission limitation recommendation, or as a separate emissions limitation recommendation when including these SSM emissions in a generally applicability emission limitation would cause the proposed emissions limitation to be too lax during times of normal operations. DAQ will also consider work practice requirements when a numerical emissions limitation is not feasible.

DAQ will assess whether to issue the RACT determinations for the major sources through source category specific RACT regulations, or through individual permits for each major source. DAQ will then submit the rule or permit for EPA's approval into the SIP.

ATTACHMENT 1 – VOC and NOx EMISSIONS UNITS IN HA 212

This is a list of emissions units located at NOx and VOC major sources in HA 212. This list may be incomplete.

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
BA01	Natural Gas Boiler	16.8 MMBtu/hr	Kewanee	8,760 hr/yr	2.24	
BA02	Natural Gas Boiler	16.8 MMBtu/hr	Kewanee	8,760 hr/yr	2.24	
BA03	Natural Gas Boiler	25.106 MMBtu/hr	Kewanee	8,760 hr/yr	3.34	
BA04	Emergency Generator (#1) DOM: Pre- 2006	1,000 kW	Magna One	500 hr/yr	8.04	
		1,340 hp	Detroit Diesel			
BA05	Emergency Generator (#2) DOM: Pre- 2006	1,000 kW	Magna One	500 hr/yr	8.04	
		1,340 hp	Detroit Diesel			
BA06	Emergency Generator DOM: Pre- 2006	500 kW	Magna One	500 hr/yr	4.02	
		670 hp	Detroit Diesel			
BA07	Emergency Generator DOM: Pre- 2006	155 kW	Magna One	500 hr/yr	1.55	
		200 hp	Detroit Diesel			
BA11	Emergency Generator (#3) DOM: Pre- 2006	1,000 kW	Detroit	500 hr/yr	8.04	
		1,340 hp				
BA12	Emergency Generator (#4) DOM: Pre- 2006	1,000 kW	Detroit	500 hr/yr	8.04	
		1,340 hp				
BA17	Emergency Fire Pump DOM: 06/2011	526 hp	Clarke Fire Pump	500 hr/yr	0.76	
			John Deere Engine			
BA18	Emergency Fire Pump DOM: 04/2011	526 hp	Clarke Fire Pump	500 hr/yr	0.76	

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
			John Deere Engine			
BA19	Cooling tower – 3 cells	18,000 GPM	Evapco	8,760 hr/yr	0.00	
BA20	Cooling tower – 3 cells	18,000 GPM	Evapco	8,760 hr/yr	0.00	
CR01	Natural Gas Boiler	3.0 MMBtu/hr	Lochinvar	8,760 hr/yr	0.16	
CR02	Natural Gas Boiler	3.0 MMBtu/hr	Lochinvar	8,760 hr/yr	0.16	
CR03	Natural Gas Boiler	3.0 MMBtu/hr	Lochinvar	8,760 hr/yr	0.16	
CR04	Natural Gas Boiler	3.0 MMBtu/hr	Lochinvar	8,760 hr/yr	0.16	
CR05	Natural Gas Boiler	3.0 MMBtu/hr	Lochinvar	8,760 hr/yr	0.16	
CR06	Natural Gas Boiler	3.0 MMBtu/hr	Lochinvar	8,760 hr/yr	0.16	
CR07	Diesel Engine Emergency Generator DOM: 2013	1,500 kW	Caterpillar	500 hr/yr	10.18	
		3,634 hp	Caterpillar			
CR08	Diesel Engine Emergency Generator DOM: 2013	150 kW	Caterpillar	500 hr/yr	0.43	
		275 hp	Caterpillar			
CR09	Cooling Tower, 3-cell	5,400 gpm	Evapco	8,760 hr/yr	0.00	
PA12	Natural Gas Boiler #4	3.5 MMBtu/hr	Bryan	8,760 hr/yr	0.48	
PA13	Natural Gas Boiler #5	3.5 MMBtu/hr	Bryan	8,760 hr/yr	0.48	
PA14	Natural Gas Boiler #3	17.0 MMBtu/hr	Bryan	8,760 hr/yr	2.72	
PA15	Natural Gas Boiler #1	21.0 MMBtu/hr	Bryan	8,760 hr/yr	3.36	

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
PA16	Natural Gas Boiler #2	21.0 MMBtu/hr	Bryan	8,760 hr/yr	3.36	
PA17	Emergency Generator #1 DOM: 03/25/1998	2,100kW	Cummins	500 hr/yr	16.90	
		2,816 hp				
PA18	Emergency Generator #2 DOM: 02/26/1998	2,100kW	Cummins	500 hr/yr	16.90	
		2,816 hp				
PA19	2-Cell Cooling Tower #1	4,725 gpm	Baltimore Aircoil	8,760 hr/yr	0.00	
PA20	2-Cell Cooling Tower #2	4,725 gpm	Baltimore Aircoil	8,760 hr/yr	0.00	
PA21	2-Cell Cooling Tower #3	4,725 gpm	Baltimore Aircoil	8,760 hr/yr	0.00	
PA22	2-Cell Cooling Tower #4	4,725 gpm	Baltimore Aircoil	8,760 hr/yr	0.00	
PA23	2-Cell Cooling Tower #5	4,725 gpm	Baltimore Aircoil	8,760 hr/yr	0.00	
PA28	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	8,760 hr/yr	0.10	
PA29	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	8,760 hr/yr	0.10	
PA30	Natural Gas Pool Heater	1.95 MMBtu/hr	RBI Futera II	8,760 hr/yr	0.10	
PA31	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	8,760 hr/yr	0.10	
PA32	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	8,760 hr/yr	0.10	
PA33	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	8,760 hr/yr	0.10	
PA34	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	8,760 hr/yr	0.10	

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
PA35	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	8,760 hr/yr	0.10	
PA36	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	8,760 hr/yr	0.84	
IP01	Natural Gas Boiler	1.25 MMBtu/hr	Ajax	8,760 hr/yr	0.27	
IP02	Natural Gas Boiler	1.25 MMBtu/hr	Ajax	8,760 hr/yr	0.27	
IP03	Natural Gas Boiler	1.25 MMBtu/hr	Ajax	8,760 hr/yr	0.27	
IP04	Natural Gas Boiler	16.738 MMBtu/hr	Kewanee	8,760 hr/yr	3.59	
IP05	Natural Gas Boiler	16.738 MMBtu/hr	Kewanee	8,760 hr/yr	3.59	
IP06	Emergency Generator DOM: Pre-2006	470 kW	Caterpillar	500 hr/yr	4.08	
		680 hp				
IP07	Emergency Generator DOM: Pre-2006	500 kW	Caterpillar	500 hr/yr	4.53	
		755 hp				
IP08	Emergency Generator DOM: Pre-2006	600 kW	Caterpillar	500 hr/yr	5.34	
		890 hp				
IP09	Emergency Generator DOM: Pre-2006	600 kW	Caterpillar	500 hr/yr	5.34	
		890 hp				
IP10	Emergency Generator DOM: Pre-2006	280 kW	E.M. Generator	500 hr/yr	2.91	
		375 hp	Detroit			
IP11	Emergency Generator DOM: Pre-2006	500 kW	Marathon Electric	500 hr/yr	4.02	
		670 hp	Detroit			

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
IP38	Emergency Generator DOM: 2019	500 kW	Caterpillar	500 hr/yr	2.07	
PH07	Natural Gas Boiler	23.65 MMBtu/hr	Unilux	8,760 hr/yr	3.78	
PH08	Natural Gas Boiler	23.65 MMBtu/hr	Unilux	8,760 hr/yr	3.78	
PH09	Natural Gas Boiler	23.65 MMBtu/hr	Unilux	8,760 hr/yr	3.78	
PH10	Genset – Emergency	1,750 kW	Spectrum			
	Engine – Diesel DOM: 1999	2,550 hp	MTU/Detroit Diesel	500 hr/yr	15.30	
PH11	Genset – Emergency	1,750 kW	Spectrum			
	Engine – Diesel DOM: 1999	2,550 hp	MTU/Detroit Diesel	500 hr/yr	15.30	
PH12	Genset – Emergency	1,750 kW	Spectrum			
	Engine – Diesel DOM: 1999	2,550 hp	MTU/Detroit Diesel	500 hr/yr	15.30	
PH13	Genset – Emergency	1,750 kW	MTU			
	Engine – Diesel DOM: 2008	2,561 hp	MTU/Detroit Diesel	500 hr/yr	6.40	
PH14	6-Cell Cooling Tower	33,360 gpm	Baltimore Aircoil Company	8,760 hr/yr	0.00	
LI01	Natural Gas Boiler	5.0 MMBtu/hr	CAMUS	8,760 hr/yr	0.24	
LI02	Natural Gas Boiler	5.0 MMBtu/hr	CAMUS	8,760 hr/yr	0.24	
LI03	Natural Gas Boiler	5.0 MMBtu/hr	CAMUS	8,760 hr/yr	0.24	
LI04	Natural Gas Boiler	5.0 MMBtu/hr	CAMUS	8,760 hr/yr	0.24	
LI05	Natural Gas Boiler	5.0 MMBtu/hr	CAMUS	8,760 hr/yr	0.24	
LI06	Emergency Generator DOM: 2012	2,000 kW	Caterpillar	500 hr/yr	10.80	

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
		3,634 hp				
LI07	Emergency Generator DOM: 2012	2,000 kW	Caterpillar	500 hr/yr	10.80	
		3,634 hp				
LI08	Cooling Tower, 2 cell	6,000 gpm	Marley	8,760 hr/yr	0.00	
LI09	Cooling Tower, 2 cell	6,000 gpm	Marley	8,760 hr/yr	0.00	
LI10	Cooling Tower, 2 cell	6,000 gpm	Marley	8,760 hr/yr	0.00	
LI11	Natural Gas Water Heater	0.150 MMBtu/hr	AO Smith	8,760 hr/yr	0.01	
LI12	Emergency Engine DOM: 11/2012	180 kW	Deutz	500 hr/yr	0.20	
		241 hp				
LI13	Emergency Engine DOM: 11/2012	180 kW	Deutz	500 hr/yr	0.20	
		241 hp				
FMC01	Boiler	6.00 MMBtu/hr	Lochinvar	8,760 hr/yr	0.29	
FMC02	Boiler	6.00 MMBtu/hr	Lochinvar	8,760 hr/yr	0.29	
FMC03	Boiler	6.00 MMBtu/hr	Lochinvar	8,760 hr/yr	0.29	
FMC04	Boiler	6.00 MMBtu/hr	Lochinvar	8,760 hr/yr	0.29	
FMC05	Emergency Generator DOM: 1/21/2019	1,000 kW	Cummins	500 hr/yr	3.61	
		1,490 hp				
FMC06	Cooling Tower, 2-Cell	2,400 gpm/cell	Evapco	8,760 hr/yr	0.00	
FMC07	Cooling Tower, 2-Cell	2,400 gpm/cell	Evapco	8,760 hr/yr	0.00	
HA06	Natural Gas Boiler	4.50 MMBtu/hr	Bryan	8,760 hr/yr	0.22	

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
HA07	Natural Gas Boiler	9.0 MMBtu/hr	Bryan	8,760 hr/yr	1.44	
HA08	Natural Gas Boiler	8.369 MMBtu/hr	Cleaver Brooks	8,760 hr/yr	0.54	
HA09	Natural Gas Boiler	8.369 MMBtu/hr	Cleaver Brooks	8,760 hr/yr	0.54	
HA10	Natural Gas Boiler	8.369 MMBtu/hr	Cleaver Brooks	8,760 hr/yr	0.54	
HA11	Natural Gas Boiler	4.80 MMBtu/hr	Universal Energy	8,760 hr/yr	0.77	
HA12	Emergency Fire Pump DOM: Pre-2006	276 kW	Fairbanks Morse Pump	500 hr/yr	2.87	
		370 hp	Caterpillar Engine			
HA13	Emergency Generator DOM: Pre-2006	800 kW	Marathon Electric Generator	500 hr/yr	7.39	
		1,232 hp	Detroit Diesel Engine			
HA14	Emergency Generator DOM: Pre-2006	600 kW	Caterpillar	500 hr/yr	5.34	
		890 hp				
HA15	Emergency Generator DOM: Pre-2006	400 kW	Magna One Generator	500 hr/yr	4.16	
		536 hp	Detroit Diesel Engine			
HA16	Emergency Generator DOM: Pre-2006	400 kW	Magna One Generator	500 hr/yr	4.16	
		536 hp	Detroit Diesel Engine	500 hr/yr	4.16	
HA17	Emergency Generator DOM: Pre-2006	400 kW	Magna One Generator			
		536 hp	Detroit Diesel Engine			

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
HA18	Emergency Generator DOM: 1996	800 kW	Caterpillar	500 hr/yr	7.08	
		1,180 hp		8,760 hr/yr	0	
HA26	Cooling Tower, 2-Cells	4,200 gpm	Evapco			
HA27	Cooling Tower, 2-Cells	4,200 gpm	Evapco	8,760 hr/yr	0	
HA28	Cooling Tower, 2-Cells	4,200 gpm	Evapco	8,760 hr/yr	0	
FL01	Natural Gas Boiler	14.343 MMBtu/hr	Johnston	8,760 hr/yr	2.22	
FL02	Natural Gas Boiler	14.645 MMBtu/hr	Kewanee	8,760 hr/yr	3.13	
FL03	Natural Gas Boiler	14.645 MMBtu/hr	Kewanee	8,760 hr/yr	3.13	
FL04	Natural Gas Boiler	14.645 MMBtu/hr	Kewanee	8,760 hr/yr	3.13	
FL05	Natural Gas Boiler	8.165 MMBtu/hr	Cleaver Brooks	8,760 hr/yr	1.27	
FL06	Emergency Fire Pump DOM: Pre-2006	313 kW	Fairbanks Morse Pump	500 hr/yr	3.26	
		420 hp	Caterpillar Engine			
FL09	Emergency Generator DOM: 1999	750 kW	Caterpillar	500 hr/yr	6.66	
		1,109 hp				
FL10	Emergency Generator DOM: 1999	750 kW	Caterpillar	500 hr/yr	6.66	
		1,109 hp				
FL11	Emergency Generator DOM: Pre-2006	475 kW	Caterpillar	500 hr/yr	4.35	
		724 hp				
FL26	Emergency Generator DOM: 2010	600 kW	Caterpillar	500 hr/yr	3.13	
		923 hp				

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
FL28	Cooling Tower, 4-cells	9,600 gpm	Marley	8,760 hr/yr	0.00	
FL29	Cooling Tower, 2-Cells	3,800 gpm	Evapco	8,760 hr/yr	0.00	
FL30	Cooling Tower, 2-Cells	3,800 gpm	Evapco	8,760 hr/yr	0.00	
FL31	Cooling Tower, 2-Cells	3,800 gpm	Evapco	8,760 hr/yr	0.00	
CP01	Natural Gas Boiler	35.40 MMBtu/hr	Hurst	8,760 hr/yr	5.46	
CP02	Natural Gas Boiler	35.40 MMBtu/hr	Hurst	8,760 hr/yr	5.46	
CP03	Natural Gas Boiler	33.475 MMBtu/hr	Burnham	8,760 hr/yr	5.35	
CP04	Natural Gas Boiler	33.475 MMBtu/hr	Burnham	8,760 hr/yr	5.35	
CP05	Natural Gas Boiler	33.475 MMBtu/hr	Burnham	8,760 hr/yr	5.35	
CP07	Natural Gas Boiler	1.0 MMBtu/hr	Gasmaster	8,760 hr/yr	0.07	
CP13	Emergency Generator DOM: 3/5/1997	2,000 kW	Caterpillar	500 hr/yr	17.26	
		2,876 hp				
CP14	Emergency Generator DOM: 3/3/1997	2,000 kW	Caterpillar	500 hr/yr	17.26	
		2,876 hp				
CP15	Emergency Generator DOM: 08/14/1996	1,750 kW	Caterpillar	500 hr/yr	15.12	
		2,520 hp				
CP16	Emergency Generator DOM: 04/18/1995	1,250 kW	Caterpillar	500 hr/yr	10.91	
		1,818 hp				
CP17	Emergency Generator DOM: 12/10/1997	2,000 kW	Caterpillar	500 hr/yr	17.26	
		2,876 hp				

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
CP19a	Cooling Tower, Cell 1 of 3	9,000 gpm	Baltimore Aircoil	8,760 hr/yr	0.00	
CP19b	Cooling Tower, Cell 2 of 3	9,000 gpm	Baltimore Aircoil	8,760 hr/yr	0.00	
CP19c	Cooling Tower, Cell 3 of 3	9,000 gpm	Baltimore Aircoil	8,760 hr/yr	0.00	
CP20	Cooling Tower	5,750 gpm	Baltimore Aircoil	8,760 hr/yr	0.00	
CP21	Cooling Tower	5,750 gpm	Baltimore Aircoil	8,760 hr/yr	0.00	
CP22	Cooling Tower	5,750 gpm	Baltimore Aircoil	8,760 hr/yr	0.00	
CP24	Natural Gas Boiler	1.5 MMBtu/hr	RBI Futera	8,760 hr/yr	0.08	
CP25	Natural Gas Boiler	1.5 MMBtu/hr	RBI Futera	8,760 hr/yr	0.08	
CP26	Natural Gas Boiler	24.0 MMBtu/hr	Unilux	8,760 hr/yr	1.16	
CP27	Natural Gas Boiler	24.0 MMBtu/hr	Unilux	8,760 hr/yr	1.16	
CP28	Emergency Generator DOM: 2008	2,000 kW	Caterpillar	500 hr/yr	10.47	
		3,634 hp				
CP29	Emergency Generator DOM: 2008	2,000 kW	Caterpillar	500 hr/yr	10.47	
		3,634 hp				
CP30a	Cooling Tower	5,600 gpm	Composite Cooling Solutions	8,760 hr/yr	0.00	
CP30b	Cooling Tower	5,600 gpm	Composite Cooling Solutions	8,760 hr/yr	0.00	
CP32	GDO with an AST and nozzles	1,000-gallon	Fireguard	18,000 gal/yr	0.00	
CP34	Diesel Fire Pump DOM: Post-2006	525 hp	Clarke Fire Pump	500 hr/yr	1.35	
			John Deere			

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
CP35	Diesel Fire Pump DOM: Post-2006	525 hp	Clarke Fire Pump	500 hr/yr	1.35	
			John Deere			
CP37	Natural Gas Pool Heater	1.5 MMBtu/hr	RBI Futera II	8,760 hr/yr	0.08	
CP41	Natural Gas Water Heater	0.25 MMBtu/hr	A.O. Smith	8,760 hr/yr	0.10	
CP42	Natural Gas Water Heater	0.25 MMBtu/hr	A.O. Smith	8,760 hr/yr	0.10	
CP44	Natural Gas Water Heater	0.999 MMBtu/hr	Lochinvar	8,760 hr/yr	0.43	
A00704 D	Natural Gas-Fired Turbine (Unit 4); Simple Cycle	60 MW	General Electric		1,732.6	
A00701 A	Natural Gas-Fired Turbine (Unit 5); Combined Cycle	85 MW	Westinghouse		360[1]	
A00702 B	Natural Gas-Fired Turbine (Unit 6); Combined Cycle	85 MW	Westinghouse			
A00705	Natural Gas-Fired Turbine (Unit 7); Combined Cycle	85 MW	Westinghouse			
A00708	Natural Gas-Fired Turbine (Unit 8); Combined Cycle	85 MW	Westinghouse			
A00709	Lime Silo	3,700 cubic feet			--	
A00710	Soda Ash Silo (A)	4,160 cubic feet			--	
A00711	Soda Ash Silo (B)	4,160 cubic feet			--	
A00712	Cooling Tower; for Unit 9 Steam Turbine Generator	54,000 gpm			--	

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
A00713	Cooling Tower; for Unit 10 Steam Turbine Generator	54,000 gpm			--	
A21	Emergency Genset	474 hp	Kohler		2.48	
	Diesel Engine; DOM: pre-1993		Detroit Diesel			
A27	Two (2) Natural Gas-Fired Turbines (Unit 11); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney		30.96	
A28	Two (2) Natural Gas-Fired Turbines (Unit 12); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney		30.96	
A29	Two (2) Natural Gas-Fired Turbines (Unit 13); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney		30.96	
A30	Two (2) Natural Gas-Fired Turbines (Unit 14); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney		30.96	
A31	Two (2) Natural Gas-Fired Turbines (Unit 15); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney		30.96	
A32	Two (2) Natural Gas-Fired Turbines (Unit 16); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney		30.96	
A33	Two (2) Natural Gas-Fired Turbines (Unit 17); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney		30.96	
A34	Two (2) Natural Gas-Fired Turbines (Unit 18); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney		30.96	
A35	Two (2) Natural Gas-Fired Turbines (Unit 19); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney		30.96	

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
A36	Two (2) Natural Gas-Fired Turbines (Unit 20); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney		30.96	
A37	Two (2) Natural Gas-Fired Turbines (Unit 21); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney		30.96	
A38	Two (2) Natural Gas-Fired Turbines (Unit 22); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney		30.96	
A43	Gasoline Dispensing Operation; Aboveground Storage Tank; One Product Nozzle; Regular Unleaded Gasoline	1,200 Gallon			0.00	
A45	Emergency Fire Pump	460 hp	Aurora		0.62	
	Diesel Engine; DOM: 2009		Cummins			
A01	Combustion Turbine Generator #1 with a fired HRSG	35 MW	GE	8,760 hr/yr combined fuel	69.24	
A02	Combustion Turbine Generator #2 with a fired HRSG	35 MW	GE			
A03	Detroit Diesel Starter Engine, Combustion Turbine Generator #1	520 hp	Detroit	8.760 hr/yr combined fuel	69.24	
A04	Detroit Diesel Starter Engine, Combustion Turbine Generator #2	520 hp	Detroit			
A05	Auxiliary Boiler #1	218 MMBtu/h	Indeck/ Volcano	125 hr/yr	1.01	
F05	Supplemental Duct Burner, Skid #1	25 MMBtu/hr	John Zink	125 hr/yr	1.01	

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
F05a	Supplemental Duct Burner, Skid #1	25 MMBtu/hr	John Zink	8,760 hr/yr	13.94	
F06	Supplemental Duct Burner, Skid #2	25 MMBtu/hr	John Zink	6,000 hr/yr	9.33	
F06a	Supplemental Duct Burner, Skid #2	25 MMBtu/hr	John Zink			
A06	Auxiliary Boiler #2	86 MMBtu/hr	Nebraska			
A09a	Cooling Tower, 3 cells	7,666 gpm each	Thermal-Dynamics Towers Inc.			
A09b				8,760 hr/yr	0	
A09c						
A01	Gas-Fired Turbine (#3); Simple Cycle; natural gas fired; MEQ = 11.20	84.5 MW	General Electric	Natural Gas 3484 hr/yr Diesel Oil 2194 hr/yr	ng 249.11 oil 249.02	
	Gas-Fired Turbine (#3); Simple Cycle; #2 diesel oil fired; MEQ = 7.05					
A02	Gas-Fired Turbine (#4); Simple Cycle; natural gas fired; MEQ = 11.20	84.5 MW	General Electric			
	Gas-Fired Turbine (#4); Simple Cycle; #2 diesel oil fired; MEQ = 7.05					
A03	Gas-Fired Turbine (#5); Simple Cycle; natural gas fired; MEQ = 11.20	84.5 MW	General Electric			

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
	Gas-Fired Turbine (#5); Simple Cycle; #2 diesel oil fired; MEQ = 7.05					
B01	Emergency Genset	50 kW	Taylor Power	0.32		
	Diesel Engine; DOM: 1991	81 hp	Perkins			
T01	Diesel Tank, AST	5,064,081-gallon capacity	Chicago Bridge and Iron Co.	0		
B11	Air Compressor	48hp	Ingersoll Rand			
	Diesel Engine; DOM: 2000		John Deer			
D02	Fire pump	208 hp	Peerless			
	Diesel Engine; DOM 1990		Cummins			
B10	Flare					
SR04	SVE and GW Treatment					
RB004a		1.5 MMBtu/hr	Patterson-Kelley			
RB004a	External Combustion	1.5	Patterson-Kelley	225 Million cfu natural gas/year	11.94	0.66
RB004b	External Combustion	1.5	Patterson-Kelley			
RB198	External Combustion	2.40	LAARS			
RB650	External Combustion	2.00	AERCO			
RB013a	External Combustion	2.5	Patterson-Kelley			
RB013b	External Combustion	2.5	Patterson-Kelley			
RB016	External Combustion	1.05	Rite			
RB024	External Combustion	1.75	RBI			

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
RB389	External Combustion	1.5	Patterson-Kelley			
RB390	External Combustion	1.5	Patterson-Kelley			
RB655	External Combustion	4.50	Weather-Rite			
RB656	External Combustion	4.50	Weather-Rite			
RB657	External Combustion	4.77	Weather-Rite			
RB658	External Combustion	4.77	Weather-Rite			
RB036	External Combustion	3.30	Weather-Rite			
RB037	External Combustion	3.30	Weather-Rite			
RB396	External Combustion	1.5	Patterson-Kelley			
RB397	External Combustion	1.5	Patterson-Kelley			
RB558	External Combustion	2.365	JBI			
RB559	External Combustion	2.365	JBI			
RB651	External Combustion	1.500	Raypak			
RB402	External Combustion	2	Raypak			
RB403	External Combustion	2	Raypak			
RB040	External Combustion	2	Patterson-Kelley			
RB406	External Combustion	2	Patterson-Kelley			
RB049	External Combustion	2	Parker			
RB414	External Combustion	1.5	Patterson Kelley			
RB419	External Combustion	1.5	Patterson-Kelley			
RB421	External Combustion	1.8	Rite			
RB149	External Combustion	1.35	RBI			
RB426	External Combustion	1.75	RBI			

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
RB427	External Combustion	1.75	RBI			
RB581	External Combustion	1.15	Modine			
RB065a	External Combustion	4	Patterson-Kelley			
RB659	External Combustion	4.00	Patterson Kelly			
RB144	External Combustion	1.25	Patterson-Kelley			
RB439	External Combustion	1.50	Patterson-Kelley			
RB440	External Combustion	1.05	Patterson-Kelley			
RB077a	External Combustion	3	Patterson Kelley			
RB078a	External Combustion	3	Patterson Kelley			
RB079a	External Combustion	3	Patterson Kelley			
RB080	External Combustion	1.5	Patterson-Kelley			
RB081	External Combustion	1.5	Patterson-Kelley			
RB086	External Combustion	2	Patterson- Kelly			
RB094	External Combustion	1.6	Camus			
RB456	External Combustion	1.05	Patterson-Kelley			
RB457	External Combustion	1.05	Patterson-Kelley			
RB236	External Combustion	1.2205	Raypak			
RB460	External Combustion	1.63	Raypak			
RB466	External Combustion	1.7	Lochinvar			
RB467	External Combustion	1.7	Lochinvar			
RB471	External Combustion	1.65	RBI			

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
RB473	External Combustion	1.5	Patterson-Kelley			
RB482	External Combustion	3.025	Rupp Industries			
RB493	External Combustion	1.5	Thermal Solutions			
RB494	External Combustion	1.5	Thermal Solutions			
RB495	External Combustion	2	Thermal Solutions			
RB496	External Combustion	2	Thermal Solutions			
RB112[1]	External Combustion	2.392	Fulton			
RB113[1]	External Combustion	2.392	Fulton			
RB114[1]	External Combustion	2.392	Fulton			
RB620	External Combustion	1	Raypak			
RB621	External Combustion	2	Patterson Kelly			
RB622	External Combustion	2	Patterson Kelly			
RB623	External Combustion	2	Patterson Kelly			
RB660	External Combustion	1.728	Rupp Air			
RB135	External Combustion	1.8	Lochinvar			
RB136	External Combustion	1.8	Lochinvar			
RB150	External Combustion	1.26	Raypak			
RB652	External Combustion	1.050	Patterson Kelley			
RB653	External Combustion	1.680	Parker			
RB516	External Combustion	1.05	Patterson-Kelley			
RB654[2]	Various	<1.00	Various			
G001	Generator or Fire Pump	68	Cummins	10/2001	0.28	0.01
	Generator or Fire Pump					

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
G002	Generator or Fire Pump	317	Cummins	6/2003	0.64	0.01
G003	Generator or Fire Pump	99	Cummins	3/2004	0.50	0.01
	Generator or Fire Pump					
G139	Generator or Fire Pump	896	MTU	12/2015	2.51	0.01
G004	Generator or Fire Pump	287	Caterpillar	3/1989	2.22	0.01
G005	Generator or Fire Pump	535	Cummins	10/1995	2.73	0.01
G006	Generator or Fire Pump	535	Cummins	4/1996	2.73	0.01
G007	Generator or Fire Pump	535	Cummins	8/2003	2.73	0.01
G008	Generator or Fire Pump	1750	Detroit Diesel	6/1995	10.50	0.01
G009	Generator or Fire Pump	1635	Energy Now		9.81	0.01
	Generator or Fire Pump		Mitsubishi			
G090	Generator or Fire Pump	324	Cummins	5/2012	0.66	0.01
	Generator or Fire Pump					
G010	Generator or Fire Pump	1350	Cummins	3/2003	5.64	0.01
G011	Generator or Fire Pump	380	Cummins	8/1997	1.95	0.01
G012	Generator or Fire Pump	535	Cummins	10/2002	2.73	0.01
G121	Generator or Fire Pump	260	Patterson	2010	2.02	0.01
	Generator or Fire Pump		Cummins			
G014	Generator or Fire Pump	676	Caterpillar	8/1993	4.06	0.01
G091	Generator or Fire Pump	145	Cummins	4/2011	0.19	0.01
G092	Generator or Fire Pump	145	Cummins	10/2010	0.19	0.01
G085	Generator or Fire Pump	27	Kubota	11/2011	0.05	0.01
G081	Generator or Fire Pump	149	Clarke	2/2010	0.41	0.01
G130	Generator or Fire Pump	324	Cummins	4/2013	0.35	0.01
G131	Generator or Fire Pump	755	Cummins	8/2012	2.02	0.01
G017	Generator or Fire Pump	91	Detroit Diesel	9/1995	0.71	0.01
	Generator or Fire Pump					
G021	Generator or Fire Pump	317	Cummins	2/2004	0.64	0.01
G064	Generator or Fire Pump	755	Cummins	7/2008	2.02	0.01

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
G095	Generator or Fire Pump	99	Cummins	10/2005	0.50	0.01
G140	Generator or Fire Pump	20 kW	Cummins		0.14	0.01
	Generator or Fire Pump	27 hp	Kubota			
G122	Generator or Fire Pump	44.8	Kubota	9/1999	0.35	0.01
G167	Generator or Fire Pump	25 kW	Cummins	2/2019	0.13	0.01
	Generator or Fire Pump	69 hp	Cummins			
G094	Generator or Fire Pump	1,490	Cummins	11/2010	3.28	0.01
	Generator or Fire Pump					
G022a	Generator or Fire Pump	45	Kubota	5/2001	0.35	0.01
G086	Generator or Fire Pump	27	Kubota	1/2011	0.05	0.01
G165	Generator or Fire Pump	250 kW	Cummins	2009	0.53	0.01
	Generator or Fire Pump	399	Cummins			
G024	Generator or Fire Pump	56	Cummins	4/2002	0.12	0.01
G025	Generator or Fire Pump	35 kW	Cummins	6/2001		
	Generator or Fire Pump	68			0.28	0.01
G077	Generator or Fire Pump	145	Cummins	9/2008	0.16	0.01
G103	Generator or Fire Pump	130	Cummins	1/2006	1.01	0.01
G028	Generator or Fire Pump	102	Cummins	12/2000	0.51	0.01
G084	Generator or Fire Pump	27	Kubota	11/2011	0.05	0.01
G029	Generator or Fire Pump	99	Cummins	7/2004	0.50	0.01
G142	Generator or Fire Pump	350 kW	Cummins	11/2009	1.70	0.01
	Generator or Fire Pump	755 hp				
G069	Generator or Fire Pump	399	Cummins	12/2007	1.25	
G124	Generator or Fire Pump	27	Kubota	2013	0.21	
G102	Generator or Fire Pump	27	Kubota	11/2011	0.06	
G032	Generator or Fire Pump	1586	Caterpillar	2/1992	7.80	
G033	Generator or Fire Pump	1586	Caterpillar	2/1992	7.80	
G034	Generator or Fire Pump	68	Cummins	9/1998	0.28	
G035a	Generator or Fire Pump	145	Cummins	8/2010	0.16	

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
G132	Generator or Fire Pump	250	Cummins	1/2011	0.27	
G125	Generator or Fire Pump	37	Kubota	7/1999	0.29	
G120	Generator or Fire Pump	27	Kubota	8/2004	0.21	
	Generator or Fire Pump					
G097	Generator or Fire Pump	157	Caterpillar	12/2010	1.22	
G080	Generator or Fire Pump	250	Cummins	6/2008	0.41	
G036	Generator or Fire Pump	67	Waukesha	9/1981	0.52	
G126	Generator or Fire Pump	27.7	Kubota	1/1999	0.21	
G038	Generator or Fire Pump	207	Cummins	6/2006	1.60	
G067	Generator or Fire Pump	364	Cummins	9/2007	2.82	
G127	Generator or Fire Pump	27	Kubota	6/2004	0.21	
G040	Generator or Fire Pump	102	Cummins	2/2000	0.51	
G068	Generator or Fire Pump	399	Cummins	12/2007	1.25	
G137	Generator or Fire Pump	755	Cummins	8/2011	3.57	
G128	Generator or Fire Pump	27	Kubota	1/2006	0.05	
G129	Generator or Fire Pump	27	Kubota	6/2006	0.05	
G154	Generator or Fire Pump	145	Cummins	6/2016	0.19	
G166	Generator or Fire Pump	15 kW	Cummins	2019	0.51	
	Generator or Fire Pump	324	Cummins			
G135	Generator or Fire Pump	27	Kubota	9/2004	0.21	
G169	Generator or Fire Pump	100 kw	Cummins	TBD	0.25	
	Generator or Fire Pump	173 hp	Cummins			
G073	Generator or Fire Pump	364	Cummins	12/2008	0.74	
G136	Generator or Fire Pump	50 kw	Cummins	11/2012	0.17	
	Generator or Fire Pump	145				
G041	Generator or Fire Pump	1,220	Cummins	11/1991	8.07	
G149	Generator or Fire Pump	157	John Deere	2016	0.25	
	Generator or Fire Pump					
A033[3]	Generator or Fire Pump	250 kW	Olympian	2002	1.79	

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
	Generator or Fire Pump	325 bhp	International			
G141	Generator or Fire Pump	1,200	Cummins	11/2005	5.08	
G046	Generator or Fire Pump	170	Cummins	6/2004	0.84	
G047	Generator or Fire Pump	364	Cummins	8/2010	0.66	
G048	Generator or Fire Pump	182	Cummins	12/1993	0.61	
G049	Generator or Fire Pump	208	Cummins	4/2005	1.61	
G157	Generator or Fire Pump	86	Clarke	6/2014	0.26	
	Generator or Fire Pump		John Deere			
G050	Generator or Fire Pump	380	Cummins	10/2003	1.95	
G099	Generator or Fire Pump	105	John Deere	1/2004	0.29	
G160[3]	Generator or Fire Pump	150 hp (Diesel, Tier 4)	Caterpillar	2/2018	0.98	
G161[3]	Generator or Fire Pump	520 hp	Caterpillar	2018	0.16	
G162[3]	Generator or Fire Pump	111.3 hp	Caterpillar	2018	0.73	
G158[2]	Generator or Fire Pump	7.9 hp	Honda Motor Company	2014	0.38	
A032[3]	Generator or Fire Pump	250	Cummins	2013	8.06	
A076	Generator or Fire Pump	150 kW	CAT	8/2010	0.39	
	Generator or Fire Pump	201 hp	Perkins			
G164[2]	Generator or Fire Pump	16 hp	Briggs & Stratton	2016	0.77	
G159[2]	Generator or Fire Pump	16 hp	Briggs & Stratton	pre-2006	0.77	
A053	Generator or Fire Pump	581	Caterpillar	2012	0.96	
G155[1]	Generator or Fire Pump	64.5	Deutz	8/2016	0.05	
G156[1]	Generator or Fire Pump	64.5	Deutz	8/2016	0.05	
G051	Generator or Fire Pump	536	Caterpillar	2005	4.15	
G143[1]	Generator or Fire Pump	64.5	Deutz	11/2014	0.05	
G144[1]	Generator or Fire Pump	64.5	Deutz	11/2014	0.05	
G063[1,2]	Generator or Fire Pump	65	Wisconsin	8/2010	0.08	

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
G062[1,2]	Generator or Fire Pump	65	Wisconsin	N/A	0.08	
G104[1]	Generator or Fire Pump	64.5	Deutz	11/2012	0.05	
G150[1]	Generator or Fire Pump	64.5	Deutz	4/2015	0.05	
G105[1]	Generator or Fire Pump	64.5	Deutz	11/2012	0.05	
G151[1]	Generator or Fire Pump	64.5	Deutz	4/2015	0.05	
G145[1]	Generator or Fire Pump	64.5	Deutz	11/2014	0.05	
G148[1]	Generator or Fire Pump	64.5	Deutz	11/2014	0.05	
G152[1]	Generator or Fire Pump	64.5	Deutz	4/2015	0.05	
G153[1]	Generator or Fire Pump	64.5	Deutz	4/2015	0.05	
G117[1,2]	Generator or Fire Pump	65	Wisconsin	N/A	0.08	
G058[1,2]	Generator or Fire Pump	65	Wisconsin	10/2002	0.08	
G147[1]	Generator or Fire Pump	64.5	Deutz	11/2014	0.05	
G146[1]	Generator or Fire Pump	64.5	Deutz	11/2014	0.05	
G163	Generator or Fire Pump	350 kW	Caterpillar	2017	1.28	
	Generator or Fire Pump	531 hp	Caterpillar			
G168	Generator or Fire Pump	100 kW	Caterpillar		0.16	
		111.3 hp	Caterpillar			
A01	Tank 530	11,200 bbl	External Floating Roof AST w/Primary and Secondary Seal	28,560,000		
A02	Tank 531	12,890 bbl	External Floating Roof AST w/Primary and Secondary Seal	32,460,000		
A03	Tank 532	8,080 bbl	External Floating Roof AST w/Primary and Secondary Seal	20,340,000		

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
A04	Tank 533	11,330 bbl	External Floating Roof AST w/Primary and Secondary Seal	28,560,000		
A05	Tank 534	8,080 bbl	External Floating Roof AST w/Primary and Secondary Seal	20,340,000		
A06	Tank 535	8,080 bbl	External Floating Roof AST w/Primary and Secondary Seal	20,340,000		
A07	Tank 536	17,550 bbl	External Floating Roof AST w/Primary and Secondary Seal	44,220,000		
A08	Tank 537	22,250 bbl	External Floating Roof AST w/Primary and Secondary Seal	90,000,000		
A09	Tank 538	11,330 bbl	External Floating Roof AST w/Primary and Secondary Seal	28,560,000		
A10	Tank 539	11,330 bbl	External Floating Roof AST w/Primary and Secondary Seal	50,000,000		

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
A11	Tank 540	16,320 bbl	Internal Floating Roof AST w/Primary and Secondary Seal	137,000,000		
A12	Tank 541	25,100 bbl	Domed External Floating Roof AST w/Primary and Secondary Seal	864,000,000		
A13	Tank 524	18,000 bbl	Internal Floating Roof AST w/Primary and Secondary Seal	50,760,000		
A14	Tank 542	45,000 bbl	Internal Floating Roof AST w/Primary Seal	118,500,000		
A15	Tank 543	35,000 bbl	Internal Floating Roof AST w/Primary Seal	114,660,000		
A16	Tank 545	37,000 bbl	Internal Floating Roof AST w/Primary and Secondary Seal	88,200,000		
A17	Tank 546	40,000 bbl	Internal Floating Roof AST w/Primary and Secondary Seal	100,800,000		
A18	Tank 522	4,000 bbl	Internal Floating Roof AST w/Primary and Secondary Seal	9,000,000		
A19	Tank 525	50,000 bbl	Fixed Roof AST	350,000,000		

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
A20	Tank 526	50,000 bbl	Fixed Roof AST	220,500,000		
A21	Tank 547	50,000 bbl	Internal Floating Roof AST w/Primary and Secondary Seal	100,800,000		
A22	Tank 512	50,000 bbl	Fixed Roof AST	126,000,000		
A23	Tank 510	40,000 bbl	External Floating Roof AST w/Primary Seal	100,800,000		
A24	Tank 511	40,000 bbl	External Floating Roof AST w/Primary Seal	100,800,000		
A25	ASA Conductivity Improver	1.3 bbl	Fixed Roof AST	5,040		
A26	Tank 500AIA	252 bbl	Fixed Roof AST	95,949		
A27	Tank 501	4,000 bbl	Internal Floating Roof AST w/Primary and Secondary Seal	9,540,000		
A28	Tank 523	10,000 bbl	Internal Floating Roof AST w/Primary and Secondary Seal	23,580,000		
A29	Tank 544	11,000 bbl	Internal Floating Roof AST w/Primary and Secondary Seal	27,720,000		
A30	Tank 533A	252 bbl	Fixed Roof AST	95,949		
A31	Tank 537A	464 bbl	Fixed Roof AST	95,949		

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
A32	Tank 541A	380 bbl	Fixed Roof AST	148,050		
A33	Tank 541B	380 bbl	Fixed Roof AST	148,050		
A34	Tank 542D	215 bbl	Fixed Roof AST	81,207		
A35	Tank 542A	143 bbl	Fixed Roof AST	79,286		
A36	Tank 531A	143 bbl	Fixed Roof AST	55,661		
A37	Tank 542C	12 bbl	Fixed Roof AST	5,040		
A38	Tank 537B	447 bbl	Fixed Roof AST	95,949		
A39	Tank 531B	119 bbl	Fixed Roof AST	44,100		
A45	Tank 548	12,890 bbl	Domed External Floating Roof AST w/Primary and Secondary Seal	32,460,000		
A46	Tank 549	12,890 bbl	Domed External Floating Roof AST w/Primary and Secondary Seal	32,460,000		
A47	Tank 550	20,000 bbl	Internal Floating Roof AST w/Primary and Secondary Seal	70,000,000		
A48	Tank 551	10,100 bbl	Internal Floating Roof AST w/Primary and Secondary Seal	50,400,000		
A49	Tank 542B	4 bbl	Fixed Roof AST	5,040		
A53	Tank 548B	238 bbl	Fixed Roof AST	57,519		
A54	Tank 548A	238 bbl	Fixed Roof AST	95,949		
A56	Tank 513	50,000 bbl	Internal Floating Roof AST	189,000,000		

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
			w/Primary and Secondary Seal			
A57	Tank 514	50,000 bbl	Internal Floating Roof AST w/Primary and Secondary Seal	189,000,000		
A58	Tank 553	80,000 bbl	Internal Floating Roof AST w/Primary and Secondary Seal	302,400,000		
A59	Tank 554	80,000 bbl	Internal Floating Roof AST w/Primary and Secondary Seal	604,800,000		
A60	Tank 555	80,000 bbl	Internal Floating Roof AST w/Primary and Secondary Seal	604,800,000		
A61	Tank 552	40,000 bbl	Internal Floating Roof AST w/Primary and Secondary Seal	126,000,000		
B01	Loading Racks	35,379,927 bbl per year	15 Loading Lanes			
B04	Tank 500	3,000 bbl	Internal Floating Roof AST w/Primary and Secondary Seal	7,560,000		

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
B05	Tank 521	5,000 bbl	Internal Floating Roof AST w/Primary and Secondary Seal	12,720,000		
B01A	B-100	147,168,000 gallons/yr	Biodiesel Offloading Rack			
B02	John Zink VRU		Vapor control unit; loading lanes			
B06	Piping and Fittings		Misc. Losses/Leaks from Valves, Flanges, Pumps and VCU			
B10	Flare Processing		Vapor control unit for loading lanes (includes saturator and vapor holding tank)			
B11		48 hp				
D01	Tank DG	250 gal	Fixed Roof AST	25,000		
D02		208 hp				
H02	Mainline Sump	1,000 gal	Mainline Sump UST	302,400		
H03	Rack Sump	3,000 gal	Rack Sump UST	806,400		
H04	Mainline Sump	4,200 gal	New Mainline Sump UST	100,800		
H05	Cooling Tower	220 gpm	Baltimore Aircoil; M/N: F2841KE; S/N:			

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
			U013422001MAD			
H06	Nellis Sump	2,000 gal	Nellis Delivery System Sump, UST	75,600		
H07	Rack Sump	1,000 gal	Rack 6 Sump, UST	36,000		
H08	QC Sump	100 gal	Quality Control Lab Sump UST			
H09	Ethanol	76,104,000 gal/year	Ethanol unloading system			
H10	Tank 500B	10,000 gal	Fixed Roof vertical AST	132,000		
H11	OWS Tank		Oil-water separator tank	15,768,000		
H12	OST-100- DW	1,000 gal	Fixed Roof Horizontal AST w/Dual Wall	365,000		
H14	ASA Tote	350 gal	Fixed Roof Rectangular AST	390		
H15	CI Tote	350 gal	Fixed Roof Rectangular AST	3,300		
H16	Lane 7 Red Dye Tote	350 gal	Fixed Roof Rectangular AST	6,150		
H17	Lane 12 Red Dye Tote	350 gal	Fixed Roof Rectangular AST	6,150		
SR04	SVE and GW Treatment System		Soil Vapor Extraction and Groundwater Treatment			

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
			System (includes control units)			

ATTACHMENT 2 EPA CTG DOCUMENT

Pollutant	EPA Report	Description
Control Techniques Guidelines (CTG)		
VOC	EPA-450/R-75-102 *1975/11*	Design Criteria for Stage I Vapor Control Systems – Gasoline Service Stations (PDF 15 pp, 766KB) *Note – This document is regarded as a CTG although it was never published with an EPA document number.*
VOC	EPA-450/2-76-028 *1976/11*	Control of Volatile Organic Emissions from Existing Stationary Sources – Volume I: Control Methods for Surface Coating Operations (PDF 174 pp, 4.6MB) *Note – Although often listed with the CTGs for historical reasons, this document does not define RACT for any source. It is a compilation of control techniques.*
VOC	EPA-450/2-77-008 *1977/05*	Control of Volatile Organic Emissions from Existing Stationary Sources – Volume II: Surface Coating of Cans, Coils, Paper, Fabrics, Automobiles, and Light-Duty Trucks (PDF 232 pp, 2.7MB)
VOC	EPA-450/2-77-022 *1977/11*	Control of Volatile Organic Emissions from Solvent Metal Cleaning (PDF 229 pp, 7.0MB)
VOC	EPA-450/2-77-025 *1977/10*	Control of Refinery Vacuum Producing Systems, Wastewater Separators, and Process Unit Turnarounds (PDF 50 pp, 1.3MB)
VOC	EPA-450/2-77-026 *1977/10*	Control of Hydrocarbons from Tank Truck Gasoline Loading Terminals (PDF 62 pp, 1.6MB)
VOC	EPA-450/2-77-032 *1977/12*	Control of Volatile Organic Emissions from Existing Stationary Sources – Volume III: Surface Coating of Metal Furniture (PDF 66 pp, 1.9MB)
VOC	EPA-450/2-77-033 *1977/12*	Control of Volatile Organic Emissions from Existing Stationary Sources – Volume IV: Surface Coating of Insulation of Magnet Wire (PDF 44 pp, 1.1MB)

Pollutant	EPA Report	Description
VOC	EPA-450/2-77-034 *1977/12*	Control of Volatile Organic Emissions from Existing Stationary Sources – Volume V: Surface Coating of Large Appliances (PDF 70 pp, 2.1MB)
VOC	EPA-450/2-77-035 *1977/12*	Control of Volatile Organic Emissions from Bulk Gasoline Plants (PDF 49 pp, 1.3MB)
VOC	EPA-450/2-77-036 *1977/12*	Control of Volatile Organic Emissions from Storage of Petroleum Liquids in Fixed-Roof Tanks (PDF 43 pp, 1.1MB)
VOC	EPA-450/2-77-037 *1977/12*	Control of Volatile Organic Emissions from Use of Cutback Asphalt (PDF 18 pp, 481KB)
VOC	EPA-450/2-78-022 *1978/05*	Control Techniques for Volatile Organic Emissions from Stationary Sources (PDF 580 pp, 21.9MB) *Note – This document is often listed with CTGs, but it does not define RACT for any particular source*
VOC	EPA-450/2-78-015 *1978/06*	Control of Volatile Organic Emissions from Existing Stationary Sources – Volume VI: Surface Coating of Miscellaneous Metal Parts and Products (PDF 82 pp, 2.6MB)
VOC	EPA-450/2-78-032 *1978/06*	Control of Volatile Organic Emissions from Existing Stationary Sources – Volume VII: Factory Surface Coating of Flat Wood Paneling (PDF 66 pp, 2.0MB)
VOC	EPA-450/2-78-036 *1978/06*	Control of Volatile Organic Compound Leaks from Petroleum Refinery Equipment (PDF 78 pp, 6.0MB)
VOC	EPA-450/2-78-029 *1978/12*	Control of Volatile Organic Emissions from Manufacture of Synthesized Pharmaceutical Products (PDF 134 pp, 3.8MB)
VOC	EPA-450/2-78-030 *1978/12*	Control of Volatile Organic Emissions from Manufacture of Pneumatic Rubber Tires (PDF 72 pp, 1.6MB)
VOC	EPA-450/2-78-033 *1978/12*	Control of Volatile Organic Emissions from Existing Stationary Sources – Volume VIII: Graphic Arts-Rotogravure and Flexography (PDF 64 pp, 1.9MB)
VOC	EPA-450/2-78-047 *1978/12*	Control of Volatile Organic Emissions from Petroleum Liquid Storage in External Floating Roof Tanks (PDF 66 pp, 2.0MB)

Pollutant	EPA Report	Description
VOC	EPA-450/2-78-050 *1978/12*	Control of Volatile Organic Emissions from Perchloroethylene Dry Cleaning Systems (PDF 76 pp, 2.5MB) *Note – Perchloroethylene has been exempted as a VOC, so this CTG is no longer relevant. However, there is a MACT standard for perchloroethylene dry cleaners.*
VOC	EPA-450/2-78-051 *1978/12*	Control of Volatile Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems (PDF 32 pp, 887KB)
VOC	EPA-450/3-82-009 *1982/09*	Control of Volatile Organic Compound Emissions from Large Petroleum Dry Cleaners (PDF 174 pp, 5.0MB)
VOC	EPA-450/3-83-008 *1983/11*	Control of Volatile Organic Compound Emissions from Manufacture of High-Density Polyethylene, Polypropylene, and Polystyrene Resins (PDF 308 pp, 14.0MB)
VOC	EPA-450/3-83-007 *1983/12*	Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants (PDF 194 pp, 6.3MB)
VOC	EPA-450/3-83-006 *1984/03*	Control of Volatile Organic Compound Leaks from Synthetic Organic Chemical Polymer and Resin Manufacturing Equipment (PDF 148 pp, 6.2MB)
VOC	EPA-450/3-84-015 *1984/12*	Control of Volatile Organic Compound Emissions from Air Oxidation Processes in Synthetic Organic Chemical Manufacturing Industry (PDF 259 pp, 9.4MB)
VOC	EPA-450/4-91-031 *1993/08*	Control of Volatile Organic Compound Emissions from Reactor Processes and Distillation Operations in Synthetic Organic Chemical Manufacturing Industry (PDF 277 pp, 8.7MB)
VOC	EPA-453/R-96-007 *1996/04*	Control of Volatile Organic Compound Emissions from Wood Furniture Manufacturing Operations (PDF 288 pp, 13.8MB) *Note – Wood Furniture (CTG-MACT) – Draft MACT out 5-1994; Final CTG issued 4-1996. See also 61 FR-25223, May 20, 1996 and 61 FR-50823, September 27, 1996.*
VOC	EPA-453/R-94-032 *1994/04*	Alternative Control Technology Document – Surface Coating Operations at Shipbuilding and Ship Repair Facilities (PDF 217 pp,

Pollutant	EPA Report	Description
		9.8MB) *Note – For CTG, see 61 FR-44050, August 27,1996*
VOC	61 FR-44050 8/27/96 *1996/08*	Control Techniques Guidelines for Shipbuilding and Ship Repair Operations (Surface Coating) (PDF 30 pp, 4.0MB) *Note – See also EPA-453/R-94-032.*
VOC	59 FR-29216 6/06/94 *1994/06*	Aerospace MACT (PDF 37 pp, 6MB) *Note – See also EPA-453/R-97-004.*
VOC	EPA-453/R-97-004 *1997/12*	Aerospace (CTG & MACT) (PDF 62 pp, 288KB) *Note – See also 59 FR-29216, June 6, 1994.*
VOC	EPA-453/R-06-001 *2006/09*	Control Techniques Guidelines for Industrial Cleaning Solvents (PDF 290 pp, 7.6MB)
VOC	EPA-453/R-06-002 *2006/09*	Control Techniques Guidelines for Offset Lithographic Printing and Letterpress Printing (PDF 52 pp, 349KB)
VOC	EPA-453/R-06-003 *2006/09*	Control Techniques Guidelines for Flexible Package Printing (PDF 33 pp, 216KB)
VOC	EPA-453/R-06-004 *2006/09*	Control Techniques Guidelines for Flat Wood Paneling Coatings (PDF 27 pp, 212KB)
VOC	EPA 453/R-07-003 *2007/09*	Control Techniques Guidelines for Paper, Film, and Foil Coatings (PDF 102 pp, 488KB)
VOC	EPA 453/R-07-004 *2007/09*	Control Techniques Guidelines for Large Appliance Coatings (PDF 44 pp, 374KB)
VOC	EPA 453/R-07-005 *2007/09*	Control Techniques Guidelines for Metal Furniture Coatings (PDF 100 pp, 293KB)
VOC	EPA 453/R-08-003 *2008/09*	Control Techniques Guidelines for Miscellaneous Metal and Plastic Parts Coatings (PDF 143 pp, 897KB)
VOC	EPA 453/R-08-004 *2008/09*	Control Techniques Guidelines for Fiberglass Boat Manufacturing Materials (PDF 41 pp, 336KB)
VOC	EPA 453/R-08-005 *2008/09*	Control Techniques Guidelines for Miscellaneous Industrial Adhesives (PDF 47 pp, 350KB)

Pollutant	EPA Report	Description
VOC	EPA 453/R-08-006 *2008/09*	Control Techniques Guidelines for Automobile and Light-Duty Truck Assembly Coatings (PDF 44 pp, 2.64MB) *Note – See also EPA-453/R-08-002.*
VOC	EPA 453/R-08-002 *2008/09*	Protocol for Determining the Daily Volatile Organic Compound Emission Rate of Automobile and Light-Duty Truck Primer-Surfacer and Topcoat Operations (PDF 129 pp, 450KB) *Note – See also EPA-453/R-08-006.*
VOC	EPA-453/B-16-001 *2016/10*	Control Techniques Guidelines for the Oil and Natural Gas Industry (343 pp, 1.6 MB)

Appendix 2

NAFB RACT Analysis

NELLIS AIR FORCE BASE, NEVADA
SOURCE 114

REASONABLY AVAILABLE CONTROL TECHNOLOGY (RACT) ANALYSIS

September 2022

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List of Appendices

Acronyms and Abbreviations

<	less than
≤	less than or equal to
AFB	Air Force Base
AFR	air-to-fuel ratio
AP-42	Compilation of Air Emission Factors
application	Authority to Construct Permit Application
ATC	Authority to Construct
BACT	Best Available Control Technology
CARB	California Air Resources Board
CFR	Code of Federal Regulations
CO	carbon monoxide
DAQ	(Clark County) Division of Air Quality
DLN	Dry Low NOx
EF	emission factor
EGR	Exhaust Gas Recirculation
EPA	U.S. Environmental Protection Agency
EU	emission unit
g	gram(s)
GHG	greenhouse gas
HA	hydrographic area
HAP	hazardous air pollutant
HC	Hydrocarbons
hp	horsepower
hr/yr	hour(s) per year
IC	internal combustion
ITR	Injection Timing Retard
kW	kilowatt(s)
LAER	Lowest Achievable Emission Rate
lb	pound(s)
lb/hp-hr	pound(s) per horsepower-hour
N/A	not applicable
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NOx	nitrogen oxide
NSPS	New Source Performance Standards
PCC	Pre-ignition Chamber Combustion
permit	Source 114 Part 70 Operating Permit
PM	particulate matter
ppm	parts per million
PTE	potential to emit
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
RICE	Reciprocating Internal Combustion Engine
SCC	Source Classification Code
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan

SLN	SoLoNOx
SNCR	Selective Non-Catalytic Reduction
TBD	to be determined
tpy	ton(s) per year

I. Introduction

A. Purpose

In 2018, the U.S. Environmental Protection Agency (EPA) designated hydrographic area (HA) 212 in Clark County, Nevada, as nonattainment for the 2015 ozone National Ambient Air Quality Standards (NAAQS) and assigned a classification of "marginal" to the area. Under the marginal classification, HA 212 was required to reach attainment of the 2015 ozone NAAQS by 03 August 2021. In 2021, the Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ) submitted data requesting exclusion of certain monitored data from calculation of HA 212's design value based on exceptional events (wildfires and stratospheric intrusions). In July 2022, EPA proposed not to approve those demonstrations and to find that HA 212 failed to meet its attainment date based on a 2018-2020 design value of 0.074 parts per million (ppm). As a result, EPA also proposed to reclassify (bump-up) HA 212's classification to "moderate." The new classification would require HA 212 to achieve attainment by 03 August 2024 and require DAQ to establish emissions control requirements in its State Implementation Plan (SIP), including Reasonably Available Control Technology (RACT).

EPA has not defined the term, RACT, by rule, but in guidance it describes the requirement as the lowest emissions an industrial source is capable of emitting through use of control technology that is reasonably available considering technological and economic feasibility. Currently, the DAQ has identified seven nitrogen oxide (NOx) major sources that could be subject to major source RACT requirements, including Nellis Air Force Base (Nellis). DAQ requests that these sources conduct a case-specific, initial evaluation to identify potential control options, evaluate feasibility and costs, and recommend emissions limitations that might satisfy the RACT requirement.

The DAQ has requested that Nellis submit an initial evaluation and recommend emissions limitations that might satisfy the RACT requirement for NOx control for specific sources no later than 03 October 2022.

The RACT-specific information requested includes:

- Information sources relied on to identify available control options;
- Ranking of available control options based on control effectiveness;
- Evaluation of technical feasibility;
- Annual and incremental cost effectiveness ($/ton);
- Baseline and controlled tons-per-year (tpy) emissions estimates (and basis);
- Environmental, energy, and other impacts (benefits and disbenefits); greenhouse gases (GHGs), hazardous air pollutants (HAPs), or other pollutants;
- Proposed RACT emissions limitation or averaging approach;
- Schedule for installing and operating the emissions controls; and
- Proposed testing, monitoring, recordkeeping, and reporting meeting periodic monitoring requirements.

B. Resources Consulted

Nellis resources used to develop this document include the Nellis Title V Operating Permit issued 15 June 2021 and revised 24 February 2022 and potential to emit (PTE) calculations. Many additional resources and references were consulted; see appendices for additional details.

C. Emission Units Evaluated

The emission units that met the evaluation criteria of having a NOx PTE greater than 5tpy are eight emergency engines, one non-emergency engine, and one aircraft engine test cell. All three of these groups of sources are included in the Nellis Part 70 Operating Permit. **Table 1-1** provides permitted maximum-potential operations and NOx emissions.

Table 1-1 Nellis Air Force Base (AFB), NOx from RACT Analysis Sources

Source	Building Number	EU	EPA Engine Tier Rating	HP Rating	Potential Annual Hours of Operation (hr/yr)	NOx Potential to Emit (PTE) (tons/yr)
Non-Emergency Engine	Aggregate Plant	A032	Tier 2	250	2,080	8.06
Emergency Engine	202	G009	Tier 1	1,635	500	9.81
	217	G010	Tier 1	1,350	500	5.64
	1301	G032	Tier 1	1,586	500	7.80
	1301	G033	Tier 1	1,586	500	7.80
	10307	G041	Tier 1	1,220	500	8.07
	10706-1	G141	Tier 1	1,200	500	5.08
	201	G176	Tier 2	2,220	500	5.90
	1771	New	Tier 2	2,922	500	8.54
Aircraft Engine Test Cell	Hush House	N001&N002	N/A	61633/61637	-	46.42

EPA = Environmental Protection Agency
EU = emission unit
HP = horsepower
hr = hours
yr = year

The remainder of this document is organized as follows:

- Section II, Non-Emergency Stationary Engines, presents the RACT analysis for the one non-emergency engine;
- Section III, Emergency Engines, presents the RACT analysis for the eight emergency engines; and

- Section IV, Aircraft Engine Test Cell, presents the RACT analysis for one aircraft engine test cell

II. Non-Emergency Stationary Engines

A. Background Information on Source and Emission Point

EU A032 is a non-emergency generator which supports the aggregate plant. The engine specification for this unit is listed below in **Table 2-1.** The aggregate plant did not utilize this generator in 2021 and has no plans to operate it in 2022.

Table 2-1 Non-Emergency Generator Engine Data

Building Number	EU	Engine Data						
		Manufacturer	Model Number	Serial Number	Capacity (hp)	Date of Manufacture		Fuel Type
						Month	Year	
Aggregate Plant	A032	Cummins	M11	60425136	250	Unknown	2013	Diesel

The tables below (**Table 2-2** and **Table2-3**) show the actual NOx emissions and hourly usage for the last five years. As shown, A032 actual NOx emissions are well below the projected PTE emissions.

Table 2-2 Non-Emergency Generator NOx Emissions

EU	Actual NOx Emissions (tons/yr)							
	2017	2018	2019	2020	2021	Average	Max	Total
A032	0.31	0.39	0.19	0.17	0	0.21	0.39	1.06

Table 2-3 Non- Emergency Generator Usage

EU	Usage (hr/yr)				
	2017	2018	2019	2020	2021
A032	80	102	49	46	0

Existing NOx controls are:

- Annual operating limitations by permit (2,080 hr/yr);
- Good combustion practices based on manufacturer specifications; and
- Good maintenance practices

B. Review of Available Control Technologies

<u>Potential Control Technologies</u>

Potential NOx control retrofit technologies to consider are as follows:

- Selective Catalytic Reduction (SCR)
- Turbocharging
- Pre-stratified charge
- Exhaust Gas Recirculation (EGR)
- Injection Timing Retard (ITR)
- Air-to-Fuel Ratio (AFR) adjustments
- Reduction in potential maximum allowable hours of operation
- Conversion to natural gas
- Conversion to dual fuel (diesel/natural gas)
- Derating
- Replacement with Tier 4 diesel engines
- Replacement with natural gas engines
- Replacement with battery backup power
- Removal
- Selective Non-Catalytic Reduction (SNCR)
- Intake air cooling adjustment/aftercooler
- Water injection
- Water/fuel emulsions
- Alternative fuels
- Dry Low NOx (DLN) and SoLoNOx (SLN)
- Engine performance management system
- High-pressure fuel injection

An EPA RACT/BACT/LAER Clearinghouse (RBLC) search was conducted on 01 September 2022, for similar engines – both emergency and non-emergency units burning diesel fuel. Database review line items are provided in Appendix A.

<u>Potential Control Technologies Removed from Further Evaluation – Not Available/Practical</u>

From the list above, some items were removed from consideration. Controls removed are listed below:

- The unit is already equipped with turbocharging.
- The Air Force confirmed that the engine needs to remain in place for mission requirements, so removal is not an option.
- Air-to-fuel ratio adjustments were removed because manufacturer guidance indicated this adjustment is not available for these engines.
- Engine derating was removed because it was determined by engine manufacturers to not be technically beneficial in terms of grams NOx per hp-hr output for these particular engines.
- The purpose of this unit precludes any reliance on natural gas. An excerpt from the Air Force directive prohibiting use of natural gas for standby generation is provided in Appendix B. This standby generator directive is being used in this case due to the limited operation of A032 which is more in ordnance with standby generator operations.
- The utilization of battery backup power is not allowed by the mission.
- Engine performance management systems were not found to substantially reduce NOx, and the operators utilize good maintenance and operations practices as established by the manufacturer. Intake air cooling could be adjusted (i.e., by way of an after-cooler), along

with other parameters, which may improve engine performance, but no quantifiable benefit to NOx was found for intake air cooling alone.

- Water injection, which could theoretically reduce peak combustion temperatures, adversely impacts the oil film protecting the walls of the cylinders. Water/fuel emulsions, as with water injection, attack the cylinders and also the fuel system, and therefore were not considered viable by any engine manufacturers in the literature review conducted. High-pressure fuel injection was not found in any related examples to have quantifiable impact on potential NOx emissions in this study.

The following controls and processes were removed from consideration and further analysis due to non-availability:

- SNCR applies to external combustion and was noted in EPA literature as being possibly feasible for compression ignition engines, but this could not be quantified with any examples, nor was it found to be implemented with any available results during the research for this report. Therefore, SNCR was removed.
- Alternative fuels including methanol were not identified as demonstrated or available for these engines.
- DLN and SLN combustors apply primarily to turbines and utilize multistage premix combustors where the air and fuel are mixed at a lean fuel-to-air ratio. The excess air in the lean mixture acts as a heat sink, which lowers peak combustion temperatures and also ensures a more homogeneous mixture, both resulting in greatly reduced NOx formation rates. No examples could be found of applying this technology to these types of units.
- Generally, retrofits with EGR on low-load mobile diesels have been shown in research to reduce NOx by up to 40%. (MECA, 2009). No application of EGR to units similar to A032 was found. The conclusion was that EGR is not readily available, and it was removed from consideration.
- Pre-stratified charge is not applicable to or available for these units, according to the manufacturer.
- Typically, ignition timing retard generally carries penalties of increased particulates, carbon monoxide (CO), Hydrocarbons (HC), and fuel consumption, and degrades engine performance and longevity if not incorporated with electronic engine control. However, ITR was also removed from consideration because it was determined by the manufacturer to not be applicable to or available for these engines, and no vendor offerings were found.

<u>SCR Concerns</u>

SCR as a control technology includes a reducer added to the exhaust flow where reactions in a catalytic chamber take place to remove NOx.

Retrofitting the existing engine with SCR is readily available as an add-on technology for stationary diesel engines. New replacement Tier 4 manufacturer-certified engines, designed for prime use, rely heavily on SCR for NOx control, and are also readily available.

However, Nellis feels add-on SCR by way of SCR retrofit or by way of replacement with Tier 4 engines to be an impractical option for EU A032. The emission unit operates intermittently with starts and stops similar to operations of emergency engines (as defined in federal air rules), and engines that operate intermittently spend much of their time in warm-up or cool-down mode, where the exhaust is not warm enough for SCR to function.

Therefore, Nellis feels that SCR retrofit and replacement with a Tier 4 engine be removed from further analysis because it is impractical as a control technology for EU A032.

Potential Control Technologies for Further Review and Evaluation

Based on the above analysis, there is only one possible control option.

- Reduction in operating hours

Nellis would be willing to reduce the maximum engine run hours on this engine from 2,080 hours to 1,200, which would bring the PTE to below 5 tons per year at maximum capacity. As seen above, operating hours for the last five years have been below the current yearly limit and would still be below the new proposed PTE hours. Economically, this would be the most cost-effective option to bring this non-emergency generator below the initial RACT analysis guidelines of 5 tons of NOx per year.

C. Elimination of Technically Infeasible Options

As stated above, all other control technologies have been eliminated from analysis.

D. Calculation of Control Technology Cost

Reducing the PTE hourly limit for EU A032 is extremely cost-effective. This action will only cost Nellis AFB the ATC application and review fee of approximately $4,000 (this is variable based on the changing DAQ fee schedules).

E. RACT Recommendation

It is Nellis' position that reduction in operating hours is the most cost-effective NOx reduction. It is therefore proposed to limit the use of EU A032 to 1,200 hours. This will reduce the NOx PTE of EU A032 by 58%. The five-year actual average of NOx emissions is currently 97% less than the permitted PTE limit. The total sum of operating hours for the last five years is 276.83 hours, which is 77% less than the new proposed operating limit of 1,200 hours per year.

III. Emergency-Use Stationary Engines

A. Background Information on Source and Emission Point

Nellis operates eight emergency generators which exceed the 5 tons per year NOx threshold for RACT analysis. The generators support various buildings on Nellis. The engine specifications for these units are listed below in Table 3-1.

Limited data is available for EU G176, as it was newly installed in 2021 and has limited run time.

The new EU will eventually support Building 1771, which is a new facility currently under construction. An Authority to Construct (ATC) Permit has not been received from DAQ at this time.

EU G141 has no operating hours because it was never installed. The engine was not properly sized when purchased. Therefore, EU G141 is currently permitted to sit in the 820 Red Horse Power Production Shop storage yard, where it is used for spare parts. The Shop has no intention of installing this generator at a different building at this time. However, if that were to change, Nellis AFB would first submit an ATC to relocate this engine.

EU G176 and the new EU at Building 1771 are brand new units with the best available control technology (BACT) available to Nellis AFB and EU G141 is non-operational. Therefore, this analysis will only be performed on EUs G009, G010, G032, G033, and G041.

Table 3-1 Emergency Generator Engine Data

Building Number	EU	Engine Data						
		Manufacturer	Model Number	Serial Number	Capacity (hp)	Date of Manufacture		Fuel Type
						Month	Year	
202	G009	Mitsubishi	PS6	12588	1635	Unknown	Unknown	Diesel
217	G010	Cummins	QST30-G3	37205939	1350	3	2003	Diesel
1301 (Hospital)	G032	Caterpillar	3512	24Z04351	1586	2	1992	Diesel
1301 (Hospital)	G033	Caterpillar	3512	24Z04354	1586	2	1992	Diesel
10307	G041	Cummins	KTA38-G3	97494-6	1220	11	1991	Diesel
10706 -1	G141	Cummins	QSK23-G3	314180	1200	11	2005	Diesel
201	G176	Cummins	QSK-50-G4	25462291	2220	Unknown	2021	Diesel
1771	New	Cummins	QSK60-G6 NR2	TBD	2922	TBD	TBD	Diesel

The tables below (**Table 3-2** and **Table 3-3**) show the actual emergency and maintenance and testing hourly usage for the last five years.

Table 3-2 Emergency Generator Emergency Usage

EU	Emergency Usage (hr/yr)				
	2017	2018	2019	2020	2021
G009	1.2	0.2	0.7	0.6	11.9
G010	5.5	67.9	78.7	0.2	0.1
G032	3.3	0.0	6.2	0.2	2.0
G033	3.3	0.0	6.2	0.1	1.9
G041	37.0	51.2	57.6	13.0	5.3
G141	Not Installed	Not Installed	Not Installed	Not Installed	Not Installed
G176	Not Installed	Not Installed	Not Installed	Not Installed	0.0
New	Not Installed	Not Installed	Not Installed	Not Installed	Not Installed

Table 3-3 Emergency Generator Maintenance and Testing Usage

EU	Maintenance and Testing Usage (hr/yr)				
	2017	2018	2019	2020	2021
G009	16.5	12.5	15.3	14.2	14.0
G010	7.5	11.4	12.9	13.7	1.0
G032	37.2	35.5	35.6	17.2	24.5
G033	36.6	35.7	35.5	17.1	25.7
G041	9.1	11.1	64.1	12.0	25.1
G141	Not Installed	Not Installed	Not Installed	Not Installed	Not Installed
G176	Not Installed	Not Installed	Not Installed	Not Installed	2.1
New	Not Installed	Not Installed	Not Installed	Not Installed	Not Installed

Table 3-4 shows the actual NOx emissions for the last five years. As shown, actual NOx emissions are well below the projected PTE emissions in **Table 1-1**.

Table 3-4 Emergency Generator NOx Emissions

EU	Actual NOx Emissions (tons/yr)							
	2017	2018	2019	2020	2021	Average	Max	Total
G009	0.269	0.281	0.292	0.285	0.477	0.321	0.477	1.604
G010	0.191	0.911	1.042	0.013	0.026	0.437	1.042	2.183

EU	Actual NOx Emissions (tons/yr)							
	2017	2018	2019	2020	2021	Average	Max	Total
G032	0.605	0.555	0.365	0.385	0.731	0.528	0.731	2.641
G033	0.608	0.553	0.363	0.402	0.702	0.526	0.702	2.628
G041	0.776	1.861	1.123	0.610	0.279	0.930	1.861	4.649
G141	Not Installed	Not Installed	Not Installed	Not Installed	Not Installed	Not Installed	Not Installed	Not Installed
G176	Not Installed	Not Installed	Not Installed	Not Installed	0.020	0.020	0.020	0.020
New	Not Installed	Not Installed	Not Installed	Not Installed	Not Installed	Not Installed	Not Installed	Not Installed

Existing NOx controls are:

- Annual operating limitations by permit (500 hr/yr);
- Good combustion practices based on manufacturer specifications; and
- Good maintenance practices

B. Review of Available Control Technologies

Potential Control Technologies

Potential NOx control retrofit technologies to consider are as follows:

- Selective Catalytic Reduction (SCR)
- Turbocharging
- Pre-stratified charge
- Exhaust Gas Recirculation (EGR)
- Injection Timing Retard (ITR)
- Air-to-Fuel Ratio (AFR) adjustments
- Reduction in potential maximum allowable hours of operation
- Conversion to natural gas
- Conversion to dual fuel (diesel/natural gas)
- Derating
- Replacement with Tier 4 diesel engines
- Replacement with Tier 3 diesel engines
- Replacement with Tier 2 diesel engines
- Replacement with natural gas engines
- Replacement with battery backup power
- Removal
- Selective Non-Catalytic Reduction (SNCR)
- Intake air cooling adjustment/aftercooler
- Water injection
- Water/fuel emulsions
- Alternative fuels
- Dry Low NOx (DLN) and SoLoNOx (SLN)
- Engine performance management system
- High pressure fuel injection

An EPA RACT/BACT/LAER Clearinghouse (RBLC) search was conducted on 01 September 2022, for similar engines – both emergency and non-emergency units burning diesel fuel. Database review line items are provided in Appendix A.

Potential Control Technologies Removed from Further Evaluation – Not Available/Practical

From the lists above, some items were removed from consideration. Controls removed are listed below:

- The units are already equipped with turbocharging.
- The Air Force confirmed that the engines need to remain in place for mission requirements, so removal is not an option.
- Air-to-fuel ratio adjustments were removed because manufacturer guidance indicated this adjustment is not available for these engines.
- Engine derating was removed because it was determined by the manufacturer to not be technically beneficial in terms of grams NOx per hp-hr output for these particular engines.
- For the purpose of the mission, it was confirmed that the currently permitted maximum potential hours of operation cannot be reduced, so reduction in potential operating hours was removed from consideration.
- The mission and purpose of these units precludes any reliance on natural gas. An excerpt from the Air Force directive prohibiting use of natural gas for standby generation is provided in Appendix B.
- Likewise, the utilization of battery backup power is not allowed by the mission.
- Engine performance management systems were not found to substantially reduce NOx, and the operators utilize good maintenance and operations practices as established by the manufacturers. Intake air cooling could be adjusted (i.e., by way of an after-cooler), along with other parameters, which may improve engine performance, but no quantifiable benefit to NOx was found for intake air cooling alone.
- Water injection which could theoretically reduce the peak combustion temperatures, adversely impacts the oil film protecting the walls of the cylinders. Water/fuel emulsions, as with water injection, attack the cylinders and also the fuel system, and therefore were not considered viable by any engine manufacturers in the literature review conducted. High-pressure fuel injection was not found in any related examples to have quantifiable impact on potential NOx emissions.

The following controls and processes were removed from consideration and further analysis due to non-availability:

- SNCR applies to external combustion and was noted in EPA literature as being possibly feasible for compression ignition engines, but this could not be quantified with any examples, nor was it found to be implemented with any available results, during the research for this report. Therefore, SNCR was removed.
- Alternative fuels including methanol were not identified as demonstrated or available for these engines.

- DLN and SLN combustors apply primarily to turbines and utilize multistage premix combustors where the air and fuel are mixed at a lean fuel-to-air ratio. The excess air in the lean mixture acts as a heat sink, which lowers peak combustion temperatures and also ensures a more homogeneous mixture, both resulting in greatly reduced NOx formation rates. However, no examples could be found of applying this technology to these types of diesel units.
- Generally, retrofits with EGR on low-load mobile diesels have been shown in research to reduce NOx by up to 40% (MECA, 2009). No application of EGR to units similar to were found. The conclusion was that EGR is not readily available, and it was removed from consideration.
- Pre-stratified charge is not applicable or available for these units, according to the manufacturer.
- Typically, ignition timing retard generally carries penalties of increased particulates, CO, HC, and fuel consumption, and degrades engine performance and longevity if not incorporated with electronic engine control. However, ITR was also removed from consideration because it determined by the manufacturer to not be applicable to or available for these engines, and no vendor offerings were found.

<u>SCR Concerns</u>

As mentioned above in the non-emergency engine section, SCR as a control technology and Tier 4 manufacturer-certified engines are not recommended by CARB for emergency generators. As all generators in this section are true emergency generators, Nellis feels that SCR retrofit and Tier 4 replacement be removed from further analysis because it is not an appropriate control technology.

<u>Potential Control Technologies for Further Review and Evaluation</u>

Based on the above analysis, there are two possible control options.

- Replacement with Tier 2 diesel engines
- Replacement with Tier 3 diesel engines

To estimate the theoretical percent reduction of NOx after replacement with Tier 2 diesel engines, the current emission factor from either the Compilation of Air Emission Factors (AP-42) or manufacturer data was compared to the Tier 2 NOx emission standard (6.4 g/kW-hr), to arrive at a percent reduction for each engine ranging from 37% to 60%, as shown in Appendix C.

Tier 3 standards are only required for non-emergency units, per Reciprocating Internal Combustion Engine (RICE) National Emission Standards for Hazardous Air Pollutants (NESHAP) and related New Source Performance Standards (NSPS). Tier 3, generally, is achieved by more advanced engine design such as water induction at some point in the combustion process and may in some cases use limited after-treatment on the exhaust to achieve the lower NOx standard.

The tier 3 standard applicable to non-emergency, stationary diesel generators sized 500 kW or less, is 4.0 g/kW-hr. So, if there were a corresponding Tier 3 standard for emergency use engines (despite Tier 3 not applicable at this capacity), theoretical reductions for each engine range from 61% to 75%, as shown in Appendix C.

Since Tier 3 doesn't specifically apply to emergency generators, it appears reasonable that Tier 3 has not been required by the EPA in permitting (based on RBLC search) or rules (NSPS/NESHAP) for emergency engines.

C. Elimination of Technically Infeasible Options

Replacing the existing engines with new models which meet EPA Tier 2 or 3 standards would provide the power needed, using a reliable fuel source, with theoretical reduced NOx. This option is technically feasible.

D. Calculation of Control Technology Cost

Evaluation of cost follows, with detailed calculations located in Appendix C.

In estimating costs, there is generally a margin of error of plus or minus 30 percent, according to the *EPA Air Pollution Control Cost Manual,* EPA/452B-02-001, 6th edition January 2002; NOx- control SCR chapter updates August and December 2016. There are also general assumptions made for variables in the calculations which include pricing, equipment life, and interest rates.

DAQ indicated that the interest rate used should be no more than 6%. Therefore 6% interest rate is used in this report.

The cost analysis includes the capital (upfront) costs with capital recovery factored in to provide this in annualized form. Then annual operating costs are added to get the total cost per year.

Then the emission reduction is taken into account to determine the cost per ton reduced per year.

The results of the cost-estimating calculations are shown in Appendix C.

Note that estimated costs are provided as a study only for purposes of this analysis and do not represent commitments or final proposed costs from any particular vendor.

Replace with Tier 2 Diesel Engines; Cost 1,000 kW Units (Average, see Appendix C for individual costs)

- Total Annualized Cost: $34,161
- Annual Pollutant Reduction: 0.28 tpy
- Cost Effectiveness: $148,072/tpy

Replace with Tier 3 Diesel Engines; Cost (Average, see Appendix C for individual costs)

- Total Annualized Cost: $173,672
- Annual Pollutant Reduction: 0.38 tpy
- Cost Effectiveness: $516,552/tpy

E. RACT Recommendation

Because of economic unreasonableness (where the cost effectiveness is based on actual emissions, and as stated, true emission reductions are expected to be much lower as these are emergency use units), Nellis does not propose to install NOx controls on these units.

Therefore, the proposed RACT is no additional controls or practices but continuing to limit hours to the permitted 500 hours per year. Engines limited to less than 500 hours per year have not traditionally required any modifications or add-on controls to comply with RACT.

The results of the RBLC database search support that adherence to manufacturer guidelines and good combustion practices are RACT for similar, limited-use engines. Tabulated RBLC results for engines burning similar fuels are shown in Appendix A. There were many similar emergency and intermittent use diesel engines that were considered RACT with no additional controls or practices, other than the limited use (emergency) and preventive requirement of good combustion practices. RBLC listed many Tier 2 emergency engines, as required by NSPS. Injection timing retard was mentioned in several RBLC records, but only for engines Tier 1 or higher on which ignition timing that is optimized for NOx is part of the engine control system design.

Nellis proposes to document usage of emergency engines, as permitted and required by 40 Code of Federal Regulations (CFR) 63 Subpart ZZZZ.

Immediate implementation is assumed. There are no proposed changes to RACT for emergency generators.

IV. Aircraft Engine Test Cell

A. Background Information on Source and Emission Points

An aircraft engine hush house allows for off-wing aircraft engine diagnostics and testing. Aircraft engines, which have been removed from the aircraft, are placed on a permanent stand within the hush house for the testing.

At the hush house, the engines are tested in different operating modes, such as idle, military, and afterburner to ensure that the engines meet specific engineering requirements. These various operating modes are similar to mobile emissions from actual aircraft in the same modes.

Potential emissions in the permit are based on maximum possible test times in each test modes, while actual emissions are estimated based on actual test times and modes utilized during the year.

Table 4-1 shows the specific NO_x emission factors for the engine testing that takes place at the Hush House in Buildings 61633 and 61637, and **Table 4-2** shows the actual emission for the periods listed.

Table 4-1 Aircraft Engine Test Cell Emission Factors

Aircraft Engine	Mode	NO_x Emission Factor (lb/1,000 lb fuel)
F100-PW-220	Idle	4.61
	Military	29.60
	AB-5	8.20
F100-PW-229	Idle	3.80
	Military	29.29
	AB-1	14.30
F119-PW-100	Idle	3.01
	Military	19.81
	Afterburner	7.37

Table 4-2 Aircraft Engine Test Cell NOx Emissions

Time Period	Actual NOx Emissions (tons/yr)
2021	8.34
2020	7.81
2019	12.90
2018	9.88
2017	9.18
Average Yearly NOx Emissions	**9.622**
Annual Permit Allowable NOx	**46.42**

B. Review of Available Control Technologies

Aircraft Engine Testing control options from the RBLC, were pulled on 17 August 2022.

Tabulated RBLC results for N001 & N002 aircraft engine testing are shown in Appendix A. Three similar facilities were considered RACT with no additional controls or practices, other than the preventive requirement of good management practices.

There were no control measures located for aircraft engine testing or similar sources in the *EPA's Menu of Control Measures 2013*.

C. Elimination of Technologically Infeasible Options

No elimination step was necessary.

D. Calculation of Control Technology Cost

No estimating of costs was necessary.

E. RACT Recommendation

Based on the RBLC database search for similar facilities (showing that LAER/BACT is no controls; see Appendix A), and since the aircraft engines are required to be tested under operating conditions as similar as possible to their operation on aircraft, no add-on combustion controls are proposed for this facility. The allowable emissions of NOx are less than 46.42 tons per year. However, actual emissions are historically much lower, with only 8.34 tons of actual NOx emissions from the hush house in 2021. Adherence with permit limits will be consistently tracked and followed. Nellis AFB requests that continuing with these practices be considered RACT for this source.

Records of all actual test times and modes, which roll up monthly, will continue to be utilized to show compliance with annual permit limits.

Since the above is already being done for the units, this would be considered immediate RACT implementation.

No readily available control technologies were identified for evaluation, and therefore economic supporting information is not enclosed. The RBLC review confirms this, as no economic information was reviewed for the similar sources.

Appendix A RBLC Data Review

Nellis AFB
RACT Analysis
RBLC Search

RBLCID	FACILITY_NAME	CORPORATE_OR_COMPANY_NAME	FACILITY_STATE	PERMIT_ISSUANCE_DATE	PROCESS_NAME	PROCCESS_TYPE	PRIMARY_FUEL	PROCESS_NOTES	POLLUTANT	CONTROL_METHOD_CODE	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT	EMISSION_LIMIT_1_AVG_TIME_CONDITION	CASE-BY-CASE_BASIS	OTHER_APPLICABLE_REQUIREMENTS	OTHER_FACTORS	PERCENT_EFFICIENCY	COMPLIANCE_VERIFIED	EMISSION_LIMIT_2	EMISSION_LIMIT_2_UNIT	EMISSION_LIMIT_2_AVGERAGE_TIME_CONDITION	POLLUTANT_COMPLIANCE_NOTES
AK-0082	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	01/23/2015 ACT	Emergency Camp Generators	17.11	Ultra Low Sulfur Diesel	Three 2,695 hp ULSD-fired Standby Camp Generator Engines.	Nitrogen Oxides (NOx)	N		4.8	GRAMS/HP-H		BACT-PSD		U	0	U	0			
AK-0082	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	01/23/2015 ACT	Airstrip Generator Engine	17.21	Ultra Low Sulfur Diesel	One 490 hp Airstrip Generator Engine	Nitrogen Oxides (NOx)	N		4.8	GRAMS/HP-H		BACT-PSD		U	0	U	0			
AK-0082	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	01/23/2015 ACT	Agitator Generator Engine	17.21	Ultra Low Sulfur Diesel	ULSD-fired 98 hp Agitator Generator Engine	Nitrogen Oxides (NOx)	N		5.6	GRAMS/HP-H		BACT-PSD		U	0	U	0			
AK-0082	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	01/23/2015 ACT	Fine Water Pumps	17.11	Ultra Low Sulfur Diesel	Two ULSD-fired 610 hp Fine Water Pumps	Nitrogen Oxides (NOx)	N		3	GRAMS/HP-H		BACT-PSD		U	0	U	0			
AK-0082	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	01/23/2015 ACT	Bulk Tank Generator Engines	17.11	Ultra Low Sulfur Diesel	Two ULSD-fired 891 hp Bulk Tank Storage Area Generator Engines	Nitrogen Oxides (NOx)	N		4.8	GRAMS/HP-H		BACT-PSD		U	0	U	0			
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	06/30/2017 ACT	Black Start and Emergency Internal Cumbustion Engines	17.11	Diesel	Two (2) 600 kWe black start diesel generators and four (4) 1,500 kWe emergency diesel generators.	Nitrogen Oxides (NOx)	P	Good Combustion Practices	8	G/KW-HR	3-HOUR AVERAGE	BACT-PSD	NSPS	U	0	U	0			8.0 g/kW-hr includes NOx and VOC emissions. NSPS Subpart IIII engines.

AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	06/30/2017 ACT	Fire Pump Diesel Internal Combustion Engines	17.21	Diesel	Three (3) 252 hp fire pump diesel internal combustion engines.	Nitrogen Oxides (NOx)	P	Good Combustion Practices	3.7	G/KW-HR	3-HOUR AVERAGE	BACT-PSD	NSPS	U	0	U	0			83.70 g/kW-hr includes NOx and VOC emissions. NSPS Subpart IIII engines.
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	06/30/2017 ACT	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	17.11	Diesel and Natural Gas	Twelve 17-MW Wartsila 18V50DF ULSD/Natural Gas-Fired Internal Combustion Engines. Each engine rated at: 143.5 MMBtu/hr on ULSD 141.4 MMBtu/hr on natural gas	Nitrogen Oxides (NOx)	B	Selective Catalytic Reduction (SCR) and Good Combustion Practices	0.53	G/KW-HR (ULSD)	3-HOUR AVERAGE	BACT-PSD		U	95	U	0.08	G/KW-HR (NATURAL GAS)	3-HOUR AVERAGE	Potential NOx emissions of 85.9 tpy for each engine (EU 1-12).
AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	08/13/2020 ACT	One (1) Black Start Generator Engine	17.11	ULSD	EU 39 is a 4,060 hp diesel generator.	Nitrogen Oxides (NOx)	P	Good combustion practices, limit operation to 500 hours per year.	3.3	G/HP-HR	3-HOUR AVERAGE	BACT-PSD	NSPS , NESHAP	U	0	U	0			EU 39 is an EPA Tier 4 Final Engine. 3.3 g/hp-hr limit includes 25% not to exceed factor of safety.
AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	08/13/2020 ACT	Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators	17.21	ULSD	Three firewater pump engines (EUs 40 - 42) rated at 250 hp each with 14.47 gph diesel throughput. Dormitory Emergency Generator Engine (EU 43) rated at 335 hp with 19.4 gph of diesel throughput. Communications Tower Emergency Generator Engine (EU 44) rated at 200 hp with 11.64 gph of diesel throughput.	Nitrogen Oxides (NOx)	P	Good combustion practices, limit operation to 500 hours per year per engine	3.6	G/HP-HR	3-HOUR AVERAGE	BACT-PSD	NSPS , NESHAP	U	0	U	0			EUs 40 - 44 are required to achieve EPA Tier 3 emission status. 3.6 g/hp-hr limit is 95% of the total for NMHC + NOx and includes a 25% not to exceed factor of safety.

AK-0088	LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	07/07/2022 ACT	Diesel Fire Pump Engine	17.11	Diesel	EU 11 is a 575 hp diesel fire pump engine which is required to meet E.F.s from Table 4 of NSPS Subpart IIII, which is the equivalent to EPA Nonroad Tier 3. BACT E.F.s include not to exceed factor of safety as identified in 40 CFR 1039.101(e).	Nitrogen Oxides (NOx)	P	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII	3.6	G/HP-HR		BACT-PSD	NSPS	U	0	U	500	HRS/YR		NOx emissions from diesel firewater pump engine EU 11 will not exceed 3.6 g/hp-hr @ 15% O2 (95% of NMHC + NOx from Table 4 of NSPS Subpart IIII, also equivalent to EPA Tier 3, includes 25% not to exceed factor of safety);
AK-0088	LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	07/07/2022 ACT	Auxiliary Air Compressor Engine	17.21	Diesel	EU 12 is a 300 hp diesel auxiliary air compressor engine which is required to meet EPA nonroad Tier 4 final E.F.s. BACT E.F.s include not to exceed factor of safety as identified in 40 CFR 1039.101(e).	Nitrogen Oxides (NOx)	P	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII	0.45	G/HP-HR		BACT-PSD	NSPS	U	0	U	500	HRS/YR		NOx emissions from the auxiliary air compressor diesel engine EU 12 will not exceed 0.45 g/hp-hr @ 15% O2 (EPA Tier 4 Final, includes 50% not to exceed factor of safety).
AL-0301	NUCOR STEEL TUSCALOOSA, INC.	NUCOR STEEL TUSCALOOSA, INC.	AL	07/22/2014 ACT	DIESEL FIRED EMERGENCY GENERATOR	17.11	DIESEL		Nitrogen Oxides (NOx)	N		0.015	LB/HP-H		BACT-PSD	NSPS , MACT	N	0	N	0			
*AL-0318	TALLADEGA SAWMILL	GEORGIA PACIFIC WOOD PRODUCTS, LLC	AL	12/18/2017 ACT	250 Hp Emergency CI, Diesel-fired RICE	17.11	Diesel	Emergency Only	Nitrogen Oxides (NOx)	N		0			N/A		U	0	U	0			
AL-0328	PLANT BARRY	ALABAMA POWER COMPANY	AL	11/09/2020 ACT	Diesel Emergency Engines	17.11	Diesel		Nitrogen Oxides (NOx)	N		3	GR/BHP-HR	NMHC + NOX	BACT-PSD	NSPS , SIP , OPERATING PERMIT	U	0	N	0			
AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	09/23/2019 ACT	Emergency Engines	17.11	Diesel		Nitrogen Oxides (NOx)	P	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.4	G/KW-H		BACT-PSD		U	0	U	0			

Nellis AFB
RACT Analysis
RBLC Search

AR-0163	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	06/09/2019 ACT	Emergency Engines	17.11	Diesel	The emergency generators are diesel fired generators which provide electrical power in the event of power failure.	Nitrogen Oxides (NOx)	P	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	4.86	G/KW-HR		BACT-PSD		U	0	U	0			
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	09/16/2014 ACT	Main Propulsion Generator Diesel Engines	17.11	Diesel	Four 1998 Wartsila 18V32LNE 9910 hp and Two 1998 Wartsila 12V32LNE 6610 hp	Nitrogen Oxides (NOx)	B	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	12.7	G/KW-H	ROLLING 24 HOUR AVERAGE	BACT-PSD	OPERATING PERMIT	U	0	U	0			
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	09/16/2014 ACT	Diesel Powered Forklift Engine	17.21	Diesel		Nitrogen Oxides (NOx)	P	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine	0			BACT-PSD	OPERATING PERMIT	U	0	U	0			

FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	09/16/2014 ACT	Wireline Diesel Engines	17.21	Diesel	Wireline engines, electric line engines, casing unit engines, tubing running engine, fluid filtration pump engine, powerpack engine, slickline powerpack engine, and CT pump engine	Nitrogen Oxides (NOx)	B	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine and with turbocharger, aftercooler, and high injection pressure	0			BACT-PSD	OPERATING PERMIT	U	0	U	0			
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	09/16/2014 ACT	Water Blasting Diesel Engine	17.21	Diesel		Nitrogen Oxides (NOx)	B	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine and with turbocharger, aftercooler, and high injection pressure	0			BACT-PSD	OPERATING PERMIT	U	0	U	0			
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	09/16/2014 ACT	Well Evaluation Diesel Engine	17.21	Diesel		Nitrogen Oxides (NOx)	P	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine	0			BACT-PSD	OPERATING PERMIT	U	0	U	0			

FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	09/16/2014 ACT	Fast Rescue Craft Diesel Engine	17.21	Diesel		Nitrogen Oxides (NOx)	B	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine and with turbocharger, aftercooler, and high injection pressure	0			BACT-PSD	OPERATING PERMIT	U	0	U	0			
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	09/16/2014 ACT	Escape Capsule Diesel Engine	17.21	Diesel		Nitrogen Oxides (NOx)	P	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine	0			BACT-PSD	OPERATING PERMIT	U	0	U	0			
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	09/16/2014 ACT	Emergency Diesel Engine	17.11	Diesel	1998 Wartsila 6R32LNE	Nitrogen Oxides (NOx)	B	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	0			BACT-PSD	OPERATING PERMIT	U	0	U	0			

FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	09/16/2014 ACT	Remotely Operated Vehicle Emergency Generator	17.21	Diesel	2004 Cummins QSM11-G2NR3	Nitrogen Oxides (NOx)	B	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	0			BACT-PSD	OPERATING PERMIT	U	0	U	0			
FL-0350	ANADARKO PETROLEUM, INC DIAMOND BLACKHAWK DRILLING PROJECT	ANADARKO PETROLEUM, INC.	FL	12/31/2014 ACT	Main Propulsion Generator Engines	17.11	Diesel	Six 2012 Hyundai-HiMsen 9H32/40V 6,035 hp and two 2012 Hyundai-HiMsen 18H32/40V diesel electric engines.	Nitrogen Oxides (NOx)	P	Use of good combustion practices based on the most recent manufacturerâ€™s specifications issued for these engines at the time that the engines are operating under this permit	0			BACT-PSD	OPERATING PERMIT	U	0	U	0			DR-ME-01 through DR-ME-08 Operating at 50% Load and Above: 10.57 g/kw-hr on a rolling 24-hour average basis. DR-ME-01 through DR-ME-06 Operating Below 50% Load: 57.3 lb/hr on a rolling 24-hour average basis. DR-MR-07 and DR-ME-08 Operating Below 50% Load: 103.5 lb/hr on a rolling 24-hour average basis.
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	SHADY HILLS ENERGY CENTER, LLC	FL	07/27/2018 ACT	1,500 kW Emergency Diesel Generator	17.11	ULSD	The emergency generator will operate a combined total of 100 hr/yr for maintenance checks, and readiness testing, which includes a maximum 50 hr/yr for non-emergency operation.	Nitrogen Oxides (NOx)	P	Operate and maintain the engine according to the manufacturer's written instructions	6.4	G/KW-HOUR		BACT-PSD	NESHAP , NSPS	U	0	U	0			Standard equals Subpart IIII limit. Limit is for NOX and Non-Methane Hydrocarbons

FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	SHADY HILLS ENERGY CENTER, LLC	FL	07/27/2018 ACT	Emergency Fire Pump Engine (347 HP)	17.21	ULSD	Limits equal Subpart IIII limits	Nitrogen Oxides (NOx)	P	Operate and maintain the engine according to the manufacturer's written instructions	4	G/KW-HR		BACT-PSD	NSPS , NESHAP	U	0	U	0			Certified engine, no testing required. Limit is for NOx + NMHC
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	SHADY HILLS ENERGY CENTER, LLC	FL	06/07/2021 ACT	1,500 kW Emergency Diesel Generator	17.11	ULSD	The emergency generator will operate a combined total of 100 hr/yr for maintenance checks, and readiness testing, which includes a maximum 50 hr/yr for non-emergency operation.	Nitrogen Oxides (NOx)	N		6.4	G/KW-HOUR	FOR NMHC +NOX	BACT-PSD	NSPS	U	0	U	0			
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	SHADY HILLS ENERGY CENTER, LLC	FL	06/07/2021 ACT	Emergency Fire Pump Engine (347 HP)	17.21	ULSD	Limits equal Subpart IIII limits	Nitrogen Oxides (NOx)	N		4	G/KW-HOUR	NMHC + NOX STANDARD	BACT-PSD	NSPS	U	0	U	0			
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	10/26/2012 ACT	Emergency Generator	17.11	diesel fuel	rated @ 2,000 KW	Nitrogen Oxides (NOx)	P	good combustion practices	6	G/KW-H	AVERAGE OF 3 STACK TEST RUNS	BACT-PSD		U	0	U	6.61	TONS/YR	ROLLING 12 MONTH TOTAL	
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	10/26/2012 ACT	Fire Pump	17.21	diesel fuel	rated @ 235 KW	Nitrogen Oxides (NOx)	P	good combustion practices	3.75	G/KW-H	AVERAGE OF 3 STACK TEST RUNS	BACT-PSD		U	0	U	0.49	TONS/YR	ROLLING 12 MONTH TOTAL	
IL-0114	CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	09/05/2014 ACT	Emergency Generator	17.11	distillate fuel oil		Nitrogen Oxides (NOx)	P	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	0.67	G/KW-H		BACT-PSD		U	0	U	0			

IL-0114	CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	09/05/2014 ACT	Firewater Pump Engine	17.21	distillate fuel oil		Nitrogen Oxides (NOx)	P	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	3.5	G/KW-H		BACT-PSD		U	0	U	0			
IL-0129	CPV THREE RIVERS ENERGY CENTER	CPV THREE RIVERS, LLC	IL	07/30/2018 ACT	Emergency Engines	17.11	Ultra-low sulfur diesel	Two emergency engine-generators. One large emergency engine-generator, 1500 kW output, will provide emergency power to the plant. One small emergency engine-generator, 125 kW output, will provide emergency power to the switchyard. Fuel used in the emergency engines must meet the requirements of 40 CFR 80.510(b), pursuant to 40 CFR 60.4207(b).	Nitrogen Oxides (NOx)	N		0			LAER	NSPS	U	0	U	0			Limits of the NSPS, 40 CFR 60 Subpart IIII, are LAER for NOx. For the large engine: 6.4 g/kW-hr For the small engine: 4.0 g/kW-hr Permit limits are as follows: For the large engine: 23.0 lb/hr and 1.7 ton/yr For the small engine: 1.2 lb/hr and 0.09 ton/yr
IL-0129	CPV THREE RIVERS ENERGY CENTER	CPV THREE RIVERS, LLC	IL	07/30/2018 ACT	Firewater Pump Engine	17.21	Ultra-low sulfur diesel	A 422 horsepower engine will power the pump in the firewater system. Fuel must meet the requirements of 40 CFR 80.510(b), pursuant to 40 CFR 60.4207(b).	Nitrogen Oxides (NOx)	N		0			LAER	NSPS	U	0	U	0			Limits of the NSPS, 40 CFR 60 Subpart IIII, are LAER for NOx. For NOx: 4.0 g/kW-hr
IL-0130	JACKSON ENERGY CENTER	JACKSON GENERATION, LLC	IL	12/31/2018 ACT	Firewater Pump Engine	17.21	Ultra-Low Sulfur Diesel	One engine will power the pump in the firewater system. The fuel must meet the requirements of 40 CFR 80.510(b) pursuant to 40 CFR 60.4207(b).	Nitrogen Oxides (NOx)	N		4	G/KW-HR		LAER	NSPS	N	0	U	0			NSPS Subpart IIII limit of 4.0 g/kW-hr is LAER

IL-0130	JACKSON ENERGY CENTER	JACKSON GENERATION, LLC	IL	12/31/2018 ACT	Emergency Engine	17.11	Ultra-Low Sulfur Diesel	One large emergency engine-generator at the plant; one small emergency engine-generator at the switchyard. Fuel must meet the requirements at 40 CFR 80.510(b) pursuant to 40 CFR 60.4207(b)	Nitrogen Oxides (NOx)	N		6.4	G/KW-HR		LAER	NSPS	U	0	U	0			NSPS Subpart IIII limit of 6.4 g/kW-hr is LAER
*IL-0133	LINCOLN LAND ENERGY CENTER	LINCOLN LAND ENERGY CENTER (A/K/A EMBERCLEAR)	IL	07/29/2022 ACT	Emergency Engines	17.11	Ultra-Low Sulfur Diesel	Two engine-generators will power an electrical generator to provide power to critical equipment during power outages. Ultra-low sulfur diesel fuel (sulfur content <15 part per million (ppm)) will be used as fuel	Nitrogen Oxides (NOx)	N		6.4	GRAMS	KILOWATT-HOUR	BACT-PSD	NSPS	U	0	U	0			Limit 1 includes non-methane hydrocarbons (NMHC), i.e. NOx + NMHC, consistent with the NSPS, 40 CFR 60 Subpart IIII.
*IL-0133	LINCOLN LAND ENERGY CENTER	LINCOLN LAND ENERGY CENTER (A/K/A EMBERCLEAR)	IL	07/29/2022 ACT	Fire Water Pump Engine	17.21	Ultra-Low Sulfur Diesel	The fire water pump engine will power the pump in the plant's fire water system	Nitrogen Oxides (NOx)	N		4	GRAMS	KILOWATT-HOUR	BACT-PSD	NSPS	U	0	U	0			Limit 1 includes non-methane hydrocarbons (NMHC), i.e., NOx + NMHC, consistent with the NSPS, 40 CFR 60 Subpart IIII.
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	IN	12/03/2012 ACT	TWO (2) FIREWATER PUMP DIESEL ENGINES	17.21	DIESEL	THE TWO FIREWATER PUMP ENGINES, IDENTIFIED AS FP01 AND FP02, EXHAUSTING THROUGH TWO (2) VENTS.	Nitrogen Oxides (NOx)	P	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	3	G/HP-H	3 HOURS	BACT-PSD			0		500	HOURS OF OPERATION	YEARLY	LIMIT TWO IS FOR EACH FIREWATER PUMP ENGINE
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	IN	12/03/2012 ACT	TWO (2) EMERGENCY DIESEL GENERATORS	17.11	DIESEL	THE TWO INTERNAL COMBUSTION ENGINES, IDENTIFIED AS EG01 AND EG02, EXHAUST THROUGH TWO (2) VENTS.	Nitrogen Oxides (NOx)	P	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	4.8	G/HP-H	3 HOURS	BACT-PSD			0		500	HOURS OF OPERATION	YEALRY	LIMIT ONE AND TWO ARE FOR EACH GENERATOR
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	IN	12/03/2012 ACT	EMERGENCY DIESEL GENERATOR	17.11	DIESEL	THIS ONE (1) INTERNAL COMBUSTION ENGINE, IDENTIFIED AS EG03, EXHAUSTS THROUGH ONE (1) VENT.	Nitrogen Oxides (NOx)	A	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	4.8	G/HP-H	3 HOURS	BACT-PSD			0		500	HOURS OF OPERATION	YEARLY	LIMIT ONE AND TWO ARE FOR EACH GENERATOR

IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	06/04/2014 ACT	DIESEL FIRED EMERGENCY GENERATOR	17.11	NO. 2, DIESEL	ANNUAL OPERATING HOURS SHALL NOT EXCEED 500 HOURS. INSIGNIFICANT ACTIVITY WILL NOT BE TESTED.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES	4.46	G/BHP-H	3-HR AVERAGE	BACT-PSD		N	0		0			
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	06/04/2014 ACT	FIRE PUMP	17.21		OPERATION LIMITED TO 500 HOURS PER YEAR. INSIGNIFICANT ACTIVITY, WILL NOT BE TESTED.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES	2.83	G/BHP-H	3-HR AVERAGE	BACT-PSD		N	0		0			
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	06/04/2014 ACT	RAW WATER PUMP	17.21	DIESEL, NO. 2	OPERATION NOT TO EXCEED 500 HOURS PER YEAR. INSIGNIFICANT ACTIVITY, WILL NOT BE TESTED.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES	2.83	G/BHP-H	3-HR AVERAGE	BACT-PSD		N	0		0			
IN-0179	OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	09/25/2013 ACT	DIESEL-FIRED EMERGENCY GENERATOR	17.11	NO. 2 FUEL OIL	ANNUAL HOURS OF OPERATION NOT TO EXCEED 200 HOURS.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES	4.46	G/B-HP-H	3-HR AVERAGE	BACT-PSD		N	0		0			ADD ON CONTROLS ARE NOT NORMALLY REQUIRED FOR LIMITED USE EMISSION UNITS.
IN-0179	OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	09/25/2013 ACT	DIESEL-FIRED EMERGENCY WATER PUMP	17.21	NO. 2 FUEL OIL	ANNUAL OPERATION LIMITED TO 200 HR,	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES	2.86	G/B-HP-H	3-HR AVERAGE	BACT-PSD		N	0		0			ADD ON CONTROLS ARE NOT NORMALLY REQUIRED FOR LIMITED USE EMISSION UNITS.
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	06/04/2014 ACT	DIESEL FIRED EMERGENCY GENERATOR	17.11	NO. 2, DIESEL	ANNUAL OPERATING HOURS SHALL NOT EXCEED 500 HOURS. INSIGNIFICANT ACTIVITY WILL NOT BE TESTED.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES	4.46	G/B-HP-H	3-HR AVERAGE	BACT-PSD		N	0		0			
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	06/04/2014 ACT	FIRE PUMP	17.21		OPERATION LIMITED TO 500 HOURS PER YEAR. INSIGNIFICANT ACTIVITY, WILL NOT BE TESTED.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES	2.83	G/B-HP-H	3-HR AVERAGE	BACT-PSD		N	0		0			
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	06/04/2014 ACT	RAW WATER PUMP	17.21	DIESEL, NO. 2	OPERATION NOT TO EXCEED 500 HOURS PER YEAR. INSIGNIFICANT ACTIVITY, WILL NOT BE TESTED.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES	2.83	G/B-HP-H	3-HR AVERAGE	BACT-PSD		N	0		0			

IN-0185	MAG PELLET LLC	MAG PELLET LLC	IN	04/24/2014 ACT	DIESEL FIRE PUMP	17.11	DIESEL		Nitrogen Oxides (NOx)	N		3	G/HP-H		BACT-PSD			0		500	H		RESTRICTED USE OF ONLY NATURAL GAS, THE USE OF GOOD COMBUSTION PRACTICES
IN-0263	MIDWEST FERTILIZER COMPANY LLC	MIDWEST FERTILIZER COMPANY LLC	IN	03/23/2017 ACT	EMERGENCY GENERATORS (EU014A AND EU-014B)	17.11	DISTILLATE OIL		Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES	4.42	G/HP-H EACH	3 HOUR AVERAGE	BACT-PSD		N	0		500	H/YR EACH		
IN-0317	RIVERVIEW ENERGY CORPORATION	RIVERVIEW ENERGY CORPORATION	IN	06/11/2019 ACT	Emergency generator EU-6006	17.11	Diesel		Nitrogen Oxides (NOx)	P	Tier II diesel engine	6.4	G/KWH	TIER II NOX + NMHC LIMIT	BACT-PSD	NSPS , NESHAP	U	0	U	0			Unit shall use good combustion practices and energy efficiency as defined in the permit. 40 CFR 60, subpart IIII 40 CFR 63, subpart ZZZZ
IN-0317	RIVERVIEW ENERGY CORPORATION	RIVERVIEW ENERGY CORPORATION	IN	06/11/2019 ACT	Emergency fire pump EU-6008	17.11	Diesel		Nitrogen Oxides (NOx)	P	Engine that complies with Table 4 to Subpart IIII of Part 60	4	G/KWH	COMBINED NOX + NMHC LIMIT	BACT-PSD	NSPS , NESHAP	U	0	U	0			Unit shall use good combustion practices and energy efficiency as defined in the permit. 40 CFR 60, subpart IIII 40 CFR 63, subpart ZZZZ
IN-0324	MIDWEST FERTILIZER COMPANY LLC	MIDWEST FERTILIZER COMPANY LLC	IN	05/06/2022 ACT	emergency generator EU 014a	17.11	distillate oil		Nitrogen Oxides (NOx)	N		4.42	G/HP-HR		BACT-PSD		U	0	U	500	HR/YR	TWELVE (12) CONSECUTIVE MONTH PERIOD	NOx emissions from the diesel-fired emergency generator (EU-014a) shall be controlled by exercising good combustion practices
IN-0324	MIDWEST FERTILIZER COMPANY LLC	MIDWEST FERTILIZER COMPANY LLC	IN	05/06/2022 ACT	fire water pump EU-015	17.11			Nitrogen Oxides (NOx)	N		2.83	G/HP-HR		BACT-PSD		U	0	U	500	HR/YR	TWELVE (12) CONSECUTIVE MONTH PERIOD	NOx emissions from the diesel-fired emergency fire water pump (EU-015) shall be controlled by good combustion practices

*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	KS	03/18/2013 ACT	Caterpillar C18DITA Diesel Engine Generator	17.11	No. 2 Distillate Fuel Oil		Nitrogen Oxides (NOx)	P	utilize efficient combustion/ design technology	14	LB/HR		BACT-PSD		U	0	U	0			
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	KS	03/18/2013 ACT	Cummins 6BTA 5.9F-1 Diesel Engine Fire Pump	17.21	No. 2 Fuel Oil		Nitrogen Oxides (NOx)	P	utilize efficient combustion/ design technology	2	LB/HR	AT FULL LOAD	BACT-PSD		U	0	U	0			
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 10-02 - North Water System Emergency Generator	17.11	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	N	0	U	0			prepare and maintain for EP 10-02, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 10-03 - South Water System Emergency Generator	17.11	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	N	0	U	0			prepare and maintain for EP 10-03, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 10-04 - Emergency Fire Water Pump	17.11	Diesel	Diesel emergency fire water pump used to provide emergency fire water supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	N	0	U	0			prepare and maintain for EP 10-04, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 11-01 - Melt Shop Emergency Generator	17.21	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.98	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	N	0	U	0			prepare and maintain for EP 11-01, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 11-02 - Reheat Furnace Emergency Generator	17.21	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.98	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	N	0	U	0			prepare and maintain for EP 11-02, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 10-07 - Air Separation Plant Emergency Generator	17.11	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	U	0	U	0			prepare and maintain for EP 10-07, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 10-01 - Caster Emergency Generator	17.11	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS	N	0	U	0			prepare and maintain for EP 10-01, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 11-03 - Rolling Mill Emergency Generator	17.21	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.98	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	N	0	U	0			prepare and maintain for EP 11-03, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 11-04 - IT Emergency Generator	17.21	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.98	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	N	0	U	0			prepare and maintain for EP 11-04, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 11-05 - Radio Tower Emergency Generator	17.21	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	3.5	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	N	0	U	0			prepare and maintain for EP 11-05, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	04/19/2021 ACT	New Pumphouse (XB13) Emergency Generator #1 (EP 08-05)	17.11	Diesel	No controls.	Nitrogen Oxides (NOx)	P	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			prepare a good combustion and operations practices (GCOP) plan that defines, measures, and verifies the use of operational and design practices determined as BACT for minimizing emissions. Any revisions to the GCOP plan requested by the Division shall be made and the revisions shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Divisionâ€™s

KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	04/19/2021 ACT	Tunnel Furnace Emergency Generator (EP 08-06)	17.11	Diesel		Nitrogen Oxides (NOx)	P	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			prepare a good combustion and operations practices (GCOP) plan that defines, measures, and verifies the use of operational and design practices determined as BACT for minimizing emissions. Any revisions to the GCOP plan requested by the Division shall be made and the revisions shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Divisionâ€™s

KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	04/19/2021 ACT	Caster B Emergency Generator (EP 08-07)	17.11	Diesel		Nitrogen Oxides (NOx)	P	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			prepare a good combustion and operations practices (GCOP) plan that defines, measures, and verifies the use of operational and design practices determined as BACT for minimizing emissions. Any revisions to the GCOP plan requested by the Division shall be made and the revisions shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Divisionâ€™s

KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	04/19/2021 ACT	Air Separation Unit Emergency Generator (EP 08-08)	17.11	Diesel		Nitrogen Oxides (NOx)	P	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			prepare a good combustion and operations practices (GCOP) plan that defines, measures, and verifies the use of operational and design practices determined as BACT for minimizing emissions. Any revisions to the GCOP plan requested by the Division shall be made and the revisions shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Divisionâ€™s

KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	04/19/2021 ACT	Cold Mill Complex Emergency Generator (EP 09-05)	17.21	Diesel		Nitrogen Oxides (NOx)	P	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			prepare a good combustion and operations practices (GCOP) plan that defines, measures, and verifies the use of operational and design practices determined as BACT for minimizing emissions. Any revisions to the GCOP plan requested by the Division shall be made and the revisions shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Divisionâ€™s

LA-0288	LAKE CHARLES CHEMICAL COMPLEX	SASOL CHEMICALS (USA) LLC	LA	05/23/2014 ACT	Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)	17.11			Nitrogen Oxides (NOx)	P	Comply with 40 CFR 60 Subpart IIII; operate the engine in accordance with the engine manufacturerâ€™s instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	27.37	LB/HR	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	1.37	TPY	ANNUAL MAXIMUM	BACT is determined to be compliance with the limitations imposed by 40 CFR 60 Subpart IIII and its associated monitoring, recordkeeping, and reporting requirements; and operating the engine in accordance with the engine manufacturerâ€™s instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage. Limit NOx + NMHC to 6.4 g/kW-hr.
LA-0292	HOLBROOK COMPRESSOR STATION	CAMERON INTERSTATE PIPELINE LLC	LA	01/22/2016 ACT	Emergency Generators No. 1 & No. 2	17.11	Diesel		Nitrogen Oxides (NOx)	P	Good equipment design, proper combustion techniques, use of low sulfur fuel, and compliance with 40 CFR 60 Subpart	14.16	LB/HR	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0.71	TPY	ANNUAL MAXIMUM	Emergency generators are also subject to a BACT limit of 1.51 lb NOx/MM Btu.

LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	SASOL CHEMICALS (USA) LLC	LA	05/23/2014 ACT	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, & 1202)	17.11	Diesel	Non-emergency use is limited to 100 hours per year.	Nitrogen Oxides (NOx)	P	Compliance with 40 CFR 60 Subpart IIII; operating the engine in accordance with the engine manufacturerâ€™s instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage.	27.37	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT , NSPS	U	0	U	1.37	TPY	ANNUAL MAXIMUM	NOx + NMHC limit is 6.40 g/kW-hr. BACT is determined to be compliance with the limitations imposed by 40 CFR 60 Subpart IIII and its associated monitoring, recordkeeping, and reporting requirements; and operating the engine in accordance with the engine manufacturerâ€™s instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage.
LA-0305	LAKE CHARLES METHANOL FACILITY	LAKE CHARLES METHANOL, LLC	LA	06/30/2016 ACT	Diesel Engines (Emergency)	17.11	Diesel		Nitrogen Oxides (NOx)	P	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	U	0	U	0			
LA-0307	MAGNOLIA LNG FACILITY	MAGNOLIA LNG, LLC	LA	03/21/2016 ACT	Diesel Engines	17.11	Diesel	Water Pumps (2 units) = 355 hp Tank Deluge Pumps (2 units) = 800 hp Generator = 1340 hp	Nitrogen Oxides (NOx)	P	combustion practices, Use ultra low sulfur diesel, and comply with 40 CFR 60 Subpart IIII	0			BACT-PSD		U	0	U	0			
LA-0308	MORGAN CITY POWER PLANT	LOUISIANA ENERGY AND POWER AUTHORITY (LEPA)	LA	09/26/2013 ACT	2000 KW Diesel Fired Emergency Generator Engine	17.11	Diesel		Nitrogen Oxides (NOx)	P	Good combustion and maintenance practices, and compliance with NSPS 40 CFR 60 Subpart IIII	33.07	LB/H	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	U	0	U	1.38	T/YR	ANNUAL MAXIMUM	

LA-0308	MORGAN CITY POWER PLANT	LOUISIANA ENERGY AND POWER AUTHORITY (LEPA)	LA	09/26/2013 ACT	380 HP Diesel Fired Pump Engine	17.21	Diesel		Nitrogen Oxides (NOx)	P	Good combustion and maintenance practices, and compliance with NSPS 40 CFR 60 Subpart IIII	2.92	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0.12	T/YR	ANNUAL MAXIMUM	
LA-0309	BENTELER STEEL TUBE FACILITY	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	LA	06/04/2015 ACT	Firewater Pump Engines	17.21	Diesel		Nitrogen Oxides (NOx)	P	Complying with 40 CFR 60 Subpart IIII	3	G/BHP-HR		BACT-PSD		U	0	U	0			
LA-0309	BENTELER STEEL TUBE FACILITY	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	LA	06/04/2015 ACT	Emergency Generator Engines	17.11	Diesel		Nitrogen Oxides (NOx)	P	Complying with 40 CFR 60 Subpart IIII	6.4	G/KW-HR		BACT-PSD		U	0	U	0			
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	LA	06/30/2017 ACT	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	17.11	Diesel	Operating hour limit: 100 hr/yr	Nitrogen Oxides (NOx)	P	Compliance with NSPS Subpart IIII	6.6	LB/HR		BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0			Limit: 3.84 g/hp-hr
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	LA	06/30/2017 ACT	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	17.11	Diesel	Operating hours limit: 100 hr/yr.	Nitrogen Oxides (NOx)	P	Compliance with NSPS Subpart IIII	19.23	LB/HR		BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0			Limit: 4.93 g/hp-hr

LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	LA	08/31/2016 ACT	SCPS Emergency Diesel Generator 1	17.11	Diesel		Nitrogen Oxides (NOx)	B	Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel).	27.34	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	6.84	T/YR	ANNUAL MAXIMUM	BACT Limit = 4.8 G/BHP-HR (NMHC + NOx)
LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	LA	08/31/2016 ACT	SCPS Emergency Diesel Firewater Pump 1	17.21	Diesel		Nitrogen Oxides (NOx)	B	Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel).	1.87	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0.47	T/YR	ANNUAL MAXIMUM	BACT Limit = 3.0 G/BHP-HR (NMHC + NOx)
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	05/23/2014 ACT	Emergency Diesel Generator 1	17.11	Diesel		Nitrogen Oxides (NOx)	P	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	52.58	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	2.63	T/YR	ANNUAL MAXIMUM	BACT Limit = 4.80 G/BHP-H (6.4 G/KW-H) (12-Month Rolling Average)
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	05/23/2014 ACT	Emergency Diesel Generator 2	17.11	Diesel		Nitrogen Oxides (NOx)	P	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	52.58	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	2.63	T/YR	ANNUAL MAXIMUM	BACT Limit = 4.80 G/BHP-H (6.4 G/KW-H) (12-Month Rolling Average)
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	05/23/2014 ACT	Fire Pump Diesel Engine 1	17.11	Diesel		Nitrogen Oxides (NOx)	P	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.6	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0.23	T/YR	ANNUAL MAXIMUM	BACT Limit = 4.80 G/BHP-H (6.40 G/KW-H) (12-Month Rolling Average)

*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	05/23/2014 ACT	Fire Pump Diesel Engine 2	17.11	Diesel		Nitrogen Oxides (NOx)	P	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.6	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0.23	T/YR	ANNUAL MAXIMUM	BACT Limit = 4.8 G/BHP-H (6.40 G/KW-H) (12-Month Rolling Average)
LA-0316	CAMERON LNG FACILITY	CAMERON LNG LLC	LA	02/17/2017 ACT	emergency generator engines (6 units)	17.11	diesel		Nitrogen Oxides (NOx)	P	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	U	0	U	0			
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	LA	12/22/2016 ACT	Emergency Generator Engines (4 units)	17.11	Diesel	I-GDE-1201, II-GDE-1201 = 2346 hp I-GDE-1202 = 755 hp I-GDE-1203 = 1193 hp	Nitrogen Oxides (NOx)	P	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			BACT = LAER (Permit 0180-00210-V4, dated 12/22/2016)
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	LA	12/22/2016 ACT	Firewater pump Engines (4 units)	17.11	diesel		Nitrogen Oxides (NOx)	P	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			BACT = LAER (Permit 0180-00210-V4, dated 12/22/2016)
LA-0318	FLOPAM FACILITY	FLOPAM, INC.	LA	01/07/2016 ACT	Diesel Engines	17.11			Nitrogen Oxides (NOx)	P	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD		U	0	U	0			
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	LA	01/09/2017 ACT	Fire Water Diesel Pump No. 3 Engine	17.11	Diesel Fuel	Emergency engine with a limit of 100 hours/yr on operating hours for ready testing.	Nitrogen Oxides (NOx)	P	operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	U	0	U	0			

LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	LA	01/09/2017 ACT	Fire Water Diesel Pump No. 4 Engine	17.11	Diesel Fuel	Emergency Engine limited to 100 hours/yr for ready tests	Nitrogen Oxides (NOx)	P	operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	U	0	U	0			
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	LA	01/09/2017 ACT	Standby Generator No. 9 Engine	17.21	Diesel Fuel	Operating hours limited to 100 hours/yr for ready testing.	Nitrogen Oxides (NOx)	P	operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	U	0	U	0			
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	09/21/2018 ACT	Firewater Pumps	17.11	Diesel Fuel		Nitrogen Oxides (NOx)	P	Good Combustion and Operating Practices.	3.1	G/HP-H		BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0			Comply with 40 CFR 60 Subpart IIII and limiting normal operations to 50 h/yr.
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	09/21/2018 ACT	Large Emergency Engines (>50kW)	17.11	Diesel Fuel	Three emergency black-start engines and two emergency generators	Nitrogen Oxides (NOx)	P	Good Combustion and Operating Practices	5.6	G/KW-H		BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0			Comply with 40 CFR 60 Subpart IIII and limiting normal operations to 100 hr/yr.
LA-0346	GULF COAST METHANOL COMPLEX	IGP METHANOL LLC	LA	01/04/2018 ACT	emergency generators (4 units)	17.11	natural gas		Nitrogen Oxides (NOx)	P	Comply with standards of 40 CFR 60 Subpart JJJJ	2	G/BHP-HR		BACT-PSD	NSPS	U	0	U	0			
LA-0350	BENTELER STEEL TUBE FACILITY	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	LA	03/28/2018 ACT	emergency generators (3 units) EQT0039, EQT0040, EQT0041	17.11			Nitrogen Oxides (NOx)	P	Comply with 40 CFR 60 Subpart IIII	0			BACT-PSD		U	0	U	0			

LA-0364	FG LA COMPLEX	FG LA LLC	LA	01/06/2020 ACT	Emergency Generator Diesel Engines	17.11	Diesel Fuel		Nitrogen Oxides (NOx)	P	compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			Engines are limited to 100 hours of non-emergency use.

LA-0364	FG LA COMPLEX	FG LA LLC	LA	01/06/2020 ACT	Emergency Fire Water Pumps	17.11	Diesel Fuel		Nitrogen Oxides (NOx)	P	Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			Engines are limited to 100 hours of non-emergency use.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	SHINTECH LOUISIANA, LLC	LA	05/04/2021 ACT	VCM Unit Emergency Generator A	17.11	Gaseous fuel	Maximum horsepower rating.	Nitrogen Oxides (NOx)	P	Good combustion practices/gaseous fuel burning.	6.9	G/HP-HR		BACT-PSD		U	0	U	0			
LA-0379	SHINTECH PLAQUEMINES PLANT 1	SHINTECH LOUISIANA, LLC	LA	05/04/2021 ACT	PVC Emergency Combustion Equipment A	17.21	Diesel	Maximum horsepower rating.	Nitrogen Oxides (NOx)	P	Good combustion practices/gaseous fuel burning.	6.9	G/HP-HR		BACT-PSD		U	0	U	0			
LA-0379	SHINTECH PLAQUEMINES PLANT 1	SHINTECH LOUISIANA, LLC	LA	05/04/2021 ACT	C/A Emergency Generator B	17.11	Gaseous fuel	Maximum horsepower rating.	Nitrogen Oxides (NOx)	P	Good combustion practices/gaseous fuel burning.	6.9	G/HP-HR		BACT-PSD		U	0	U	0			
LA-0379	SHINTECH PLAQUEMINES PLANT 1	SHINTECH LOUISIANA, LLC	LA	05/04/2021 ACT	VCM Unit Emergency Generator B	17.21	Gaseous fuel	Maximum horsepower rating.	Nitrogen Oxides (NOx)	P	Good combustion practices/gaseous fuel burning.	6.9	G/HP-HR		BACT-PSD		U	0	U	0			

LA-0379	SHINTECH PLAQUEMINES PLANT 1	SHINTECH LOUISIANA, LLC	LA	05/04/2021 ACT	VCM Unit Emergency Cooling Water Pumps	17.21	Gaseous fuel	Maximum horsepower rating. Three engines total of the same model.	Nitrogen Oxides (NOx)	P	Good combustion practices/gaseous fuel burning.	2.98	G/KW-HR		BACT-PSD		U	0	U	0			
LA-0379	SHINTECH PLAQUEMINES PLANT 1	SHINTECH LOUISIANA, LLC	LA	05/04/2021 ACT	PVC Emergency Combustion Equipment B	17.21	Gaseous fuel	Maximum horsepower rating.	Nitrogen Oxides (NOx)	P	Good combustion practices/gaseous fuel burning.	4.41	LB/MMBTU		BACT-PSD		U	0	U	0			
LA-0379	SHINTECH PLAQUEMINES PLANT 1	SHINTECH LOUISIANA, LLC	LA	05/04/2021 ACT	PVC Emergency Combustion Equipment 2A and 2B	17.21	Diesel	Maximum horsepower rating. Two engines of the same model.	Nitrogen Oxides (NOx)	P	Compliance with 40 CFR 60 Subpart IIII.	0.4	G/KW-HR		BACT-PSD	NSPS	U	0	U	0			BACT limit in terms of non-methane hydrocarbon (NMHC) + NOx.
LA-0382	BIG LAKE FUELS METHANOL PLANT	BIG LAKE FUELS LLC	LA	04/25/2019 ACT	Emergency Engines (EQT0014 - EQT0017)	17.11	Diesel		Nitrogen Oxides (NOx)	P	Comply with standards of 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	U	0	U	0			
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	LAKE CHARLES LNG EXPORT COMPANY, LLC	LA	09/03/2020 ACT	Emergency Engines (EQT0011 - EQT0016)	17.11	Diesel		Nitrogen Oxides (NOx)	P	Comply with 40 CFR 60 Subpart IIII	0			BACT-PSD		U	0	U	0			
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	FOOTPRINT POWER SALEM HARBOR DEVELOPMENT LP	MA	01/30/2014 ACT	Emergency Engine/Generator	17.11	ULSD	â‰¤ 300 hours of operation per 12-month rolling period S in ULSD: â‰¤0.0015% by weight	Nitrogen Oxides (NOx)	N		4.8	GM/BHP-H	1 HR BLOCK AVG	LAER	NSPS , NESHAP , SIP , OPERATING PERMIT	U	0	U	11.6	LB/H	1 HR BLOCK AVG	emission limits are for NOx and VOC combined total. the project is subject LAER for NOx as ozone precursor, and BACT-PSD for NOx as NO2 precursor.

MA-0039	SALEM HARBOR STATION REDEVELOPMENT	FOOTPRINT POWER SALEM HARBOR DEVELOPMENT LP	MA	01/30/2014 ACT	Fire Pump Engine	17.21	ULSD	â‰¤ 300 hours of operation per 12-month rolling period S in ULSD: â‰¤0.0015% by weight	Nitrogen Oxides (NOx)	N		3	GM/BHP-H	1 HR BLOCK AVG	LAER	NSPS , NESHAP , SIP , OPERATING PERMIT	U	0	U	2.44	LB/H	1 HR BLOCK AVG	emission limits are for NOx and VOC combined total. the project is subject LAER for NOx as ozone precursor, and BACT-PSD for NOx as NO2 precursor.
MA-0043	MIT CENTRAL UTILITY PLANT	MASSACHUSETTS INSTITUTE OF TECHNOLOGY	MA	06/21/2017 ACT	Cold Start Engine	17.11	ULSD	CAT DM8263 or equivalent. â‰¤ 8 hours of operation per day, â‰¤ 300 hours of operation per consecutive 12-month period, S in ULSD: â‰¤0.0015% by weight.	Nitrogen Oxides (NOx)	N		35.09	LB/HR	1 HR BLOCK AVG	OTHER CASE-BY-CASE	NESHAP , SIP , OPERATING PERMIT , NSPS	U	0	U	5.3	TONS/ C12MP	CONSECUTIVE TWELVE MONTH PERIOD	
MD-0042	WILDCAT POINT GENERATION FACILITY	OLD DOMINION ELECTRIC CORPORATION (ODEC)	MD	04/08/2014 ACT	EMERGENCY GENERATOR 1	17.11	ULTRA LOW SULFU DIESEL	40 CFR 60 SUBPART IIII, ULTRA LOW-SULFUR DIESEL FUEL, GOOD COMBUSTION PRACTICES	Nitrogen Oxides (NOx)	P	LIMITED OPERATING HOURS, USE OF ULTRA-LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	4.8	G/HP-H		LAER	NSPS		0		6.4	G/KW-H		COMBINED NOX AND NMHC
MD-0042	WILDCAT POINT GENERATION FACILITY	OLD DOMINION ELECTRIC CORPORATION (ODEC)	MD	04/08/2014 ACT	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	17.21	ULTRA LOW SULFUR DIESEL	40 CFR 60, SUBPART IIII, ULTRA LOW-SULFUR DIESEL FUEL, GOOD COMBUSTION PRACTICES	Nitrogen Oxides (NOx)	P	LIMITED OPERATING HOURS, USE OF ULTRA-LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	3	G/HP-H		LAER	NSPS		0		4	G/KW-H		COMBINED NOX AND NMHC

MD-0043	PERRYMAN GENERATING STATION	CONSTELLATION POWER SOURCE GENERATION, INC.	MD	07/01/2014 ACT	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DIESEL	40 CFR 60 SUBPART IIII, GOOD COMBUSTION PRACTICES	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES, LIMITED HOURS OF OPERATION, AND EXCLUSIVE USE OF ULSD	4.8	G/HP-H		LAER	NSPS		0		6.4	G/KW-H		NSPS 40 CFR 60 SUBPART IIII
MD-0043	PERRYMAN GENERATING STATION	CONSTELLATION POWER SOURCE GENERATION, INC.	MD	07/01/2014 ACT	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	17.21	ULTRAL LOW SULFUR DIESEL	40 CFR 60, SUBPART IIII, GOOD COMBUSTION PRACTICES	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES, LIMITED HOURS OF OPERATION, AND EXCLUSIVE USE OF ULSD	3	G/HP-H		LAER	NSPS		0		4	G/KW-H		NSPS 40 CFR 60 SUBPART IIII
MD-0044	COVE POINT LNG TERMINAL	DOMINION COVE POINT LNG, LP	MD	06/09/2014 ACT	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DIESEL	40 CFR 60, SUBPART IIII, ULTRA LOW-SULFUR DIESEL FUEL, GOOD COMBUSTION PRACTICES	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES AND DESIGNED TO ACHIEVE EMISSION LIMIT	4.8	G/HP-H	COMBINED NOX + NMHC	LAER	NSPS		0		6.4	G/KW-H	COMBINED NOX + NMHC	NSPS 40 CFR 60 SUBPART IIII
MD-0044	COVE POINT LNG TERMINAL	DOMINION COVE POINT LNG, LP	MD	06/09/2014 ACT	5 EMERGENCY FIRE WATER PUMP ENGINES	17.21	ULTRA LOW SULFUR DIESEL	40 CFR 60, SUBPART IIII, ULTRA LOW-SULFUR DIESEL FUEL, GOOD COMBUSTION PRACTICES	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES AND DESIGNED TO ACHIEVE EMISSION LIMIT	3	G/HP-H	NOX + NMHC	LAER	NSPS		0		4	G/KW-H	NOX + NMHC	NSPS 40 CFR 60 SUBPART IIII

MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	MI	11/01/2013 ACT	FG-EMGEN7-8; Two (2) 1,000kW diesel-fueled emergency reciprocating internal combustion engines	17.11	Diesel	1,000 kW (1,502 hp) each; hours restriction = 500 hours each per year.	Nitrogen Oxides (NOx)	P	Good combustion practices	4.8	G/B-HP-H	TEST PROTOCOL; EACH UNIT	BACT-PSD	SIP	N	0	N	0			The NOx limit of 4.8 g/bhp-hr applies to each unit.
MI-0418	WARREN TECHNICAL CENTER	GENERAL MOTORS TECHNICAL CENTER - WARREN	MI	01/14/2015 ACT	FG-BACKUPGENS (Nine (9) DRUPS Emergency Engines)	17.11	Diesel	DRUPS emergency engines identified as the following: EUDRUPS1, EUDRUPS2, EUDRUPS3, EUDRUPS4, EUDRUPS5, EUDRUPS6, EUDRUPS7, EUDRUPS8, EUDRUPS9 permitted within the flexible group that is identified as FG-BACKUPGENS. Each engine is 3490KW each. DRUPS stands for Diesel Rotary Uninterruptable Power supply system. The system provides for zero down-time in electrical energy supply at the onset of a power outage. The system stores energy in a fly-wheel that powers the generator until the diesel engine starts up. Two DRUP engines connect to one	Nitrogen Oxides (NOx)	P	No add-on controls, but injection timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	8	G/KW-H	TEST PROTOCOL (LIMIT IS PER ENGINE)	BACT-PSD	NSPS , NESHAP , SIP , OPERATING PERMIT	N	0	U	0			The emission limit is for each DRUP engine. No add-on controls were technically feasible for these emergency engines, so a cost analysis was not necessary.

MI-0418	WARREN TECHNICAL CENTER	GENERAL MOTORS TECHNICAL CENTER - WARREN	MI	01/14/2015 ACT	Four (4) emergency engines in FG-BACKUPGENS	17.11	Diesel	There are four (4) emergency engines identified as EUGENERATOR1, EUGENERATOR2, EUGENERATOR3, and EUGENERATOR4 in the flexible group identified in the permit as FG-BACKUPGENS. Each engine is 2710 KW. Two engines connect to one standard generator set.	Nitrogen Oxides (NOx)	P	No add-on controls, but injection timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	7.13	G/KW-H	TEST PROTOCOL (LIMIT IS PER ENGINE)	BACT-PSD	NSPS , NESHAP , SIP , OPERATING PERMIT	N	0	U	0			The emission limit is per engine. No add-on controls were technically feasible for these emergency engines so a cost analysis was not necessary.
MI-0421	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	08/26/2016 ACT	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	17.11	Diesel	One emergency diesel generator engine rated at 1600 kW (EUEMRGRICE in FGRICE).	Nitrogen Oxides (NOx)	P	Certified engines, limited operating hours.	22.6	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	SIP	N	0	N	0			Based on the limited hours of operation, the company concluded that add-on control would not be cost effective.
MI-0421	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	08/26/2016 ACT	Dieself fire pump engine (EUFIREPUMP in FGRICE)	17.11	Diesel	One diesel fire pump engine rated at 400 KW (identified as EUFIREPUMP in FGRICE).	Nitrogen Oxides (NOx)	P	Certified engines, limited operating hours.	3.53	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	SIP	N	0	N	0			Based on the limited hours of operation, the company concluded that add on control would not be cost effective.

MI-0423	INDECK NILES, LLC	INDECK NILES, LLC	MI	01/04/2017 ACT	EUEMENGINE (Diesel fuel emergency engine)	17.11	Diesel Fuel	a 2,922 horsepower (HP) (2,179 kilowatts (kW)) diesel fueled emergency engine manufactured in 2011 or later and a displacement of <10 liters/cylinder. Restricted to 4 hours/day, except during emergency conditions and stack testing, and 500 hours/year on a 12-month rolling time period basis.	Nitrogen Oxides (NOx)	P	Good combustion practices and meeting NSPS IIII requirements.	6.4	G/KW-H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	NSPS , SIP	N		0	N	0			The limit is actually in ‘‘NMHC + NOx‘‘ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.
MI-0423	INDECK NILES, LLC	INDECK NILES, LLC	MI	01/04/2017 ACT	EUFPENGINE (Emergency engine--diesel fire pump)	17.21	Diesel	A 260 brake horsepower (bhp) diesel-fueled emergency engine manufactured in 2011 or later and a displacement of <10 liters/cylinder. Powers a fire pump used for a back up during an emergency (EUFPENGINE). Restricted to 1 hour/day, except during emergency conditions and stack testing, and 100 hours/year on a 12-month rolling time period basis.	Nitrogen Oxides (NOx)	P	Good combustion practices and meeting NSPS Subpart IIII requirements.	3	G/BHP-H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	NSPS , SIP	N		0	N	0			The limit is actually in ‘‘NMHC + NOx‘‘ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	05/09/2017 ACT	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	17.11	Diesel	One emergency diesel generator engine rated at 1500 KW (EUEMRGRICE1 in FGRICE).	Nitrogen Oxides (NOx)	P	Certified engines, limited operating hours.	21.2	LB/H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	SIP	N		0	N	0			Based on the limited hours of operation, the company concluded that add-on control would not be cost effective.

MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	05/09/2017 ACT	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	17.11	Diesel	One emergency diesel generator engine rated at 1500 KW (EUEMRGRICE2 in FGRICE).	Nitrogen Oxides (NOx)	P	Certified engines, limited operating hours	4.4	LB/H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	SIP	N	0	N	0			Based on the limited hours of operation, the company concluded that add-on control would not be cost effective.
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	05/09/2017 ACT	EUFIREPUMP in FGRICE (Diesel fire pump engine)	17.11	Diesel	One diesel fire pump engine rated at 400 KW (EUFIREPUMP in FGRICE).	Nitrogen Oxides (NOx)	P	Certified engines. Limited operating hours.	3.53	LB/H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	SIP	N	0	N	0			Based on the limited hours of operation, the company concluded that add-on control would not be cost effective.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	MI	06/29/2018 ACT	EUFPENGINE (South Plant): Fire pump engine	17.21	Diesel	A 300 HP diesel-fired emergency fire pump engine with a model year of 2011 or later, and a displacement of <30 liters/cylinder. Equipped with a diesel particulate filter.	Nitrogen Oxides (NOx)	P	Good combustion practices and meeting NSPS Subpart IIII requirements.	3	G/BHP-H	HOURLY	BACT-PSD	SIP	N	0	N	0			The limit is actually in ‘‘NMHC + NOx‘‘ (nonmethane hydrocarbon plus NOx) which is what is required in the NSPS.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	MI	06/29/2018 ACT	EUEMENGINE (North Plant): Emergency Engine	17.11	Diesel	A 1,341 HP (1,000 kilowatts (KW)) diesel-fired emergency engine with a model year of 2011 or later, and a displacement of <10 liters/cylinder. The engine is designed to be compliant with Tier IV emission standards. Equipped with a diesel particulate filter.	Nitrogen Oxides (NOx)	P	Good combustion practices and meeting NSPS Subpart IIII requirements.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in ‘‘NMHC+ NOx‘‘ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	MI	06/29/2018 ACT	EUFPENGINE (North Plant): Fire pump engine	17.21	Diesel	A 300 HP diesel-fired emergency fire pump engine with a model year of 2011 or later, and a displacement of <30 liters/cylinder. Equipped with a diesel particulate filter.	Nitrogen Oxides (NOx)	P	Good combustion practices and meeting NSPS Subpart IIII requirements.	3	G/BHP-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in ‘‘NMHC+ NOx‘‘ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.

MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	MI	06/29/2018 ACT	EUEMENGINE (South Plant): Emergency Engine	17.11	Diesel	A 1,341 HP (1,000 kilowatts (kW)) diesel-fired emergency engine with a model year of 2011 or later, and a displacement of <10 liters/cylinder. The engine is designed to be compliant with Tier IV emission standards. Equipped with a diesel particulate filter.	Nitrogen Oxides (NOx)	P	Good combustion practices and meeting NSPS IIII requirements.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in ‘‘NMHC+NOx‘‘ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.
MI-0434	FLAT ROCK ASSEMBLY PLANT	FORD MOTOR COMPANY	MI	03/22/2018 ACT	EUENGINE 01 through EUENGINE 08	17.11	Diesel	Eight (8) diesel-fueled emergency engine/generators rated at 2,500 kilowatt (kW) / 3,633 brake horsepower (BHP), two (2) emergency fire pump engines rated at 250 BHP and an emergency engine rated at 500 kW. No add-on control.	Nitrogen Oxides (NOx)	P	Good combustion practices.	6.4	G/KW-H	HOURLY; EACH ENGINE; NMHC +NOX	BACT-PSD	NSPS , SIP	N	0	N	42.6	LB/H	HOURLY; EACH ENGINE ; NOX	The first emission limit above is actually in ‘‘NMHC+NOx‘‘ (nonmethane hydrocarbon plus NOx) and is 6.4 G/KW-H for each engine. The limit is based on NSPS IIII. The second emission limit above is actually in NOx and is 42.6 LB/H for each engine.
MI-0434	FLAT ROCK ASSEMBLY PLANT	FORD MOTOR COMPANY	MI	03/22/2018 ACT	EUFIREPUMPENGS (2 emergency fire pump engines)	17.21	Diesel	EUFIREPUMPENGS - Two (2) diesel-fueled emergency fire pump engines rated at 250 brake horsepower (BHP). No add-on control.	Nitrogen Oxides (NOx)	P	Good combustion practices.	3	G/B-HP-H	HOURLY; EACH ENGINE (NMHC +NOX)	BACT-PSD	NSPS , SIP	U	0	N	2.8	LB/H	HOURLY; EACH ENGINE (NOX)	Emission limit 1 above is actually in ‘‘NMHC+NOx‘‘ (nonmethane hydrocarbon plus NOx) and is 3.0 G/B-HP-H for each engine and is based upon NSPS IIII. Emission limit 2 is actually a NOx limit and is 2.8 LB/H for each engine.

MI-0434	FLAT ROCK ASSEMBLY PLANT	FORD MOTOR COMPANY	MI	03/22/2018 ACT	EULIFESAFETYENG - One diesel-fueled emergency engine/generator	17.21	Diesel	EULIFESAFETYENG - One (1) diesel-fueled emergency engine/generator rated at 500 KW. No add-on control.	Nitrogen Oxides (NOx)	P	Good combustion practices.	4	G/KW-H	HOURLY; NMHC +NOX	BACT-PSD	NSPS , SIP	N	0	N	8.47	LB/H	HOURLY; NOX	Emission limit 1 above is actually in ‘‘NMHC+NOx‘‘ (nonmethane hydrocarbon plus NOx) and is 4.0 G/KW-H based upon NSPS IIII. Emission limit 2 is actually NOx and is 8.47 LB/H.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	DTE ELECTRIC COMPANY	MI	07/16/2018 ACT	EUEMENGINE: Emergency engine	17.11	Diesel	A nominal 2 MW diesel-fueled emergency engine with a model year of 2011 or later, and a displacement of <10 liters/cylinder. The engine is an EPA Tier 2 certified engine subject to NSPS IIII.	Nitrogen Oxides (NOx)	P	State of the art combustion design.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in ‘‘NMHC+NOx‘‘ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	DTE ELECTRIC COMPANY	MI	07/16/2018 ACT	EUFPENGINE: Fire pump engine	17.21	Diesel	A 399 brake HP diesel-fueled emergency fire pump engine with a model year of 2011 or later, and a displacement of <10 liters/cylinder. The engine is an EPA Tier 3 certified engine subject to NSPS IIII.	Nitrogen Oxides (NOx)	P	State of the art combustion design.	4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in ‘‘NMHC+NOx‘‘ (nonmethane hydrocarbon plus NOx) which is what is required in the NSPS.
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	12/21/2018 ACT	EUEMGD1--A 1500 HP diesel fueled emergency engine	17.11	Diesel	A 1500 HP diesel-fueled emergency engine manufactured after 2006 serving a 1,000 kW engine generator with associated fuel oil tank. The engine generator is used to charge the batteries in the uninterruptible power supply battery system.	Nitrogen Oxides (NOx)	P	Good combustion practices and will be NSPS compliant.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	U	0			Emission limit is for NMHC+NOx. Did not consider the additional control to be technically feasible since many controls don't function properly for small emitters and intermittent sources.

MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	12/21/2018 ACT	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	17.11	Diesel	A 6000 HP diesel-fueled emergency engine manufactured after 2006 serving a 4000 kW generator with associated fuel oil tank. The engine generator is used to facilitate operations during idling of the plan for routine maintenance checks and readiness testing.	Nitrogen Oxides (NOx)	P	Good combustion practices and will be NSPS compliant.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	U	0			Emission limit is for NMHC+NOx. Did not consider the additional control to be technically feasible since many controls don't function properly for small emitters and intermittent sources.
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	MI	08/21/2019 ACT	FGEMENGINE	17.11	Diesel	Two (2) diesel-fired emergency engines, each 1,474 HP (1,100 kW) with a model year of 2011 or later, and a displacement of <10 liters/cylinder. The engines are designed to be compliant with Tier 2 emission standards.	Nitrogen Oxides (NOx)	N		5.3	G/HP-H	HOURLY; EACH ENGINE	BACT-PSD	NSPS	N	0	U	0			permit also with a limit of 6.4 G/KW-H, is hourly and applies to each engine. This emission limit is for certified engines; if testing becomes required to demonstrate compliance, then the tested values must be compared to the Not to Exceed (NTE) requirements determined through 40 CFR 60.4212(c). SCR is not technically feasible for emergency engines, which will be small, intermittent sources, only operated for maintenance and testing and in case of a true emergency. Other add-on controls are not considered technically or

*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	MI	11/26/2019 ACT	EUFPENGINE (Emergency engine-diesel fire pump	17.21	diesel fuel	A 260 brake horsepower (bhp) diesel-fueled emergency engine manufactured in 2011 or later and a displacement of <10 Liters/cylinder. Powers a fire pump used for back up during an emergency (EUFPENGINE). Restricted to 1 hours/day, except during emergency conditions and stack testing, and 100 hours/year on a 12-month rolling time period basis.	Nitrogen Oxides (NOx)	P	Good Combustion Practices and meeting NSPS Subpart IIII requirements	3	G/BHP-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in â€œNMHC+NOxâ€ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	MI	11/26/2019 ACT	EUEMENGINE (diesel fuel emergency engine)	17.11	diesel fuel	A 2,922 horsepower (HP) (2,179 kilowatts (kW)) natural gas-fueled emergency engine (EUEMENGINE) manufactured in 2011 or later and a displacement of <10 Liters/cylinder. Restricted to 4 hours/day, except during emergency conditions and stack testing, and 500 hours/year on a 12-month rolling time period basis	Nitrogen Oxides (NOx)	P	Good Combustion Practices and meeting NSPS Subpart IIII requirements	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in â€œNMHC+NOxâ€ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.
MI-0448	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	12/18/2020 ACT	Emergency diesel generator engine (EUEMRGRICE1 in FGRICE)	17.11	Diesel	One emergency diesel generator engine rated at 1500 KW (EUEMRGRICE1 in FGRICE).	Nitrogen Oxides (NOx)	P	Certified engines, limited operating hours	21.2	LB/H	HOURLY	BACT-PSD		N	0	N	0			Based on the limited hours of operation, Arauco concluded that add-on control would not be cost effective.

MI-0448	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	12/18/2020 ACT	Emergency diesel generator engine (EUEMRGRICE2 in FGRICE)	17.11	Diesel	One emergency diesel generator engine rated at 500 KW (EUEMRGRICE2 in FGRICE).	Nitrogen Oxides (NOx)	P	Certified Engines, Limited Operating Hours	4.4	LB/H	HOURLY	BACT-PSD		N	0	N	0			Based on the limited hours of operation, Arauco concluded that add-on control would not be cost effective.
MI-0448	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	12/18/2020 ACT	Diesel fire pump engine (EUFIREPUMP in FGRICE)	17.11	Diesel	One diesel fire pump engine rated at 400 KW (EUFIREPUMP in FGRICE).	Nitrogen Oxides (NOx)	P	Certified Engines, Limited Operating Hours	3.53	LB/H	HOURLY	BACT-PSD		N	0	N	0			Based on the limited hours of operation, Arauco concluded that add-on control would not be cost effective.
NJ-0080	HESS NEWARK ENERGY CENTER	HESS NEWARK ENERGY CENTER, LLC	NJ	11/01/2012 ACT	Emergency Generator	17.11	ULSD		Nitrogen Oxides (NOx)	P	use of ultra low sulfur diesel (ULSD) a clean fuel	18.53	LB/H		LAER	NSPS , OPERATING PERMIT	U	0	U	0			
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	NJ	03/10/2016 ACT	Diesel Fired Emergency Generator	17.11	ULSD		Nitrogen Oxides (NOx)	P	use of ultra low sulfur diesel a clean burning fuel.	42.3	LB/H		LAER	NSPS , OPERATING PERMIT	N	0	N	0			
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	NJ	03/10/2016 ACT	Emergency Diesel Fire Pump	17.21	ULSD	Maximum heat Input Rate = 2.6 MMBtu/hr	Nitrogen Oxides (NOx)	P	use of ULSD a clean burning fuel, and limited hours of operation	1.7	LB/H		LAER	NSPS , OPERATING PERMIT	N	0	N	0			

NY-0103	CRICKET VALLEY ENERGY CENTER	CRICKET VALLEY ENERGY CENTER LLC	NY	02/03/2016 ACT	Black start generator	17.11	ultra low sulfur diesel		Nitrogen Oxides (NOx)	B	Generator equipped with selective catalytic reduction. Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.	2.11	G/BHP-H	1 H	LAER		U	0	U	0			
NY-0103	CRICKET VALLEY ENERGY CENTER	CRICKET VALLEY ENERGY CENTER LLC	NY	02/03/2016 ACT	Emergency fire pump	17.21	ultra low sulfur diesel		Nitrogen Oxides (NOx)	P	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.	2.6	G/BHP-H	1 H	LAER		U	0	U	0			
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	OH	06/18/2013 ACT	Emergency fire pump engine	17.21	diesel	223.8 kW. Emergency fire pump engine restricted to 500 hours of operation per rolling 12 months.	Nitrogen Oxides (NOx)	P	Purchased certified to the standards in NSPS Subpart IIII	1.7	LB/H		BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0.43	T/YR	PER ROLLING 12-MONTHS	Additional limits: 3.5 g NOx/kW-H; and 4.0 g NMHC + NOx/kW-hr, the standard from Subpart IIII. Method 7E if required.
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	OH	06/18/2013 ACT	Emergency generator	17.11	diesel	Emergency diesel fired generator restricted to 500 hours of operation per rolling 12-months.	Nitrogen Oxides (NOx)	P	Purchased certified to the standards in NSPS Subpart IIII	27.8	LB/H		BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	6.95	T/YR	PER ROLLING 12-MONTHS	Additional limits: 5.61 g NOx/kW-H; and 6.4 g NMHC + NOx/kW-hr, the standard from Subpart IIII. Method 7E if required.

OH-0355	GENERAL ELECTRIC AVIATION, EVENDALE PLANT	GENERAL ELECTRIC	OH	05/07/2013 ACT	Test Cell 1 for Aircraft Engines and Turbines	17.11	JET FUEL	Fuels tested include jet fuel, diesel fuel, biofuels and gaseous fuels. Size of engine turbine varies, none specified. Installed with a continuous fuel flow monitor.	Nitrogen Oxides (NOx)	N		1.7	LB/MMBTU	LAER AND PSD LIMIN	LAER	SIP	U	0	U	92	T/YR	PER ROLLING 12 MONTHS	The emission limit of 1.70 LB NOX/MMBtu is considered LAER, based on design emission levels. Must develop an Emissions Protocol Document on the potential to emit.
OH-0355	GENERAL ELECTRIC AVIATION, EVENDALE PLANT	GENERAL ELECTRIC	OH	05/07/2013 ACT	Test Cell 2 for Aircraft Engines and Turbines	17.11	JET FUEL	Fuels tested include jet fuel, diesel fuel, biofuels and gaseous fuels. Size of engine turbine varies, none specified. Installed with a continuous fuel flow monitor.	Nitrogen Oxides (NOx)	N		4.4	LB/MMBTU		LAER	SIP	U	0	U	80	T/YR	PER ROLLING 12 MONTHS	The emission limit of 4.4 LB NOX/MMBtu is considered LAER, based on design emission levels. Must develop an Emissions Protocol Document on the potential to emit.
OH-0360	CARROLL COUNTY ENERGY	CARROLL COUNTY ENERGY	OH	11/05/2013 ACT	Emergency generator (P003)	17.11	diesel	1,112 kW emergency diesel fired generator.	Nitrogen Oxides (NOx)	P	Purchased certified to the standards in NSPS Subpart IIII	13.74	LB/H		BACT-PSD	NSPS	U	0	U	3.44	T/YR	PER ROLLING 12 MONTH PERIOD	Additional limits: 5.61 g NOx/kW-H; and 6.4 g NMHC + NOx/kW-hr, the standard from Subpart IIII.
OH-0360	CARROLL COUNTY ENERGY	CARROLL COUNTY ENERGY	OH	11/05/2013 ACT	Emergency fire pump engine (P004)	17.21	diesel	400 hp (298 kW) emergency diesel-fired fire pump engine	Nitrogen Oxides (NOx)	P	Purchased certified to the standards in NSPS Subpart IIII	2.3	LB/H		BACT-PSD	NSPS	U	0	U	0.57	T/YR	PER ROLLING 12 MONTH PERIOD	Additional limits: 3.5 g NOx/kW-H; and 4.0 g NMHC+NOx/kW-h (3.0 g/hp-h), the standard from Subpart IIII.
OH-0363	NTE OHIO, LLC		OH	11/05/2014 ACT	Emergency generator (P002)	17.11	Diesel fuel	Emergency diesel engine powered standby generator, rated at 1,100 kilowatts.	Nitrogen Oxides (NOx)	P	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII	29.01	LB/H		BACT-PSD	NSPS	U	0	U	7.25	T/YR	PER ROLLING 12 MONTH PERIOD	

OH-0363	NTE OHIO, LLC		OH	11/05/2014 ACT	Emergency Fire Pump Engine (P003)	17.21	Diesel fuel	Emergency diesel fire pump engine is rated at a maximum 260 BHP.	Nitrogen Oxides (NOx)	P	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII	1.72	LB/H		BACT-PSD	NSPS	U	0	U	0.43	T/YR	PER ROLLING 12 MONTH PERIOD	NSPS Subpart IIII: Non-methane hydrocarbon (NMHC) + NOx emissions shall not exceed 3.0 g/hp-hr.
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	08/25/2015 ACT	Emergency fire pump engine (P004)	17.21	Diesel fuel	140 hp (104.5 kW) emergency diesel-fired fire pump engine	Nitrogen Oxides (NOx)	P	State-of-the-art combustion design	0.81	LB/H		BACT-PSD	NSPS	U	0	U	0.2	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 3.5 g/kW-hr. NSPS: Non-methane hydrocarbon (NMHC) + NOx emissions shall not exceed 4.0 g/kW-hr.
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	08/25/2015 ACT	Emergency generator (P003)	17.11	Diesel fuel	1,750 kW (2,346 hp) emergency generator	Nitrogen Oxides (NOx)	P	State-of-the-art combustion design	21.6	LB/H		BACT-PSD	NSPS	U	0	U	5.41	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 5.61 g/kW-hr and Non-methane hydrocarbon (NMHC) + NOx emissions shall not exceed 6.4 g/kW-hr.
OH-0367	SOUTH FIELD ENERGY LLC	SOUTH FIELD ENERGY LLC	OH	09/23/2016 ACT	Emergency fire pump engine (P004)	17.21	Diesel fuel	311 hp (232.1 kW mechanical) emergency fire pump	Nitrogen Oxides (NOx)	P	State-of-the-art combustion design	1.79	LB/H		BACT-PSD	NSPS	U	0	U	0.45	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 3.5 g/kW-hr. NSPS: Non-methane hydrocarbon (NMHC) + NOx emissions shall not exceed 4.0 g/kW-hr.
OH-0367	SOUTH FIELD ENERGY LLC	SOUTH FIELD ENERGY LLC	OH	09/23/2016 ACT	Emergency generator (P003)	17.11	Diesel fuel	2,000 kW electric, 2,198 kW mechanical (2,947 hp) emergency diesel generator	Nitrogen Oxides (NOx)	P	State-of-the-art combustion design	27.18	LB/H		BACT-PSD	NSPS	U	0	U	6.8	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 5.61 g/kW-hr. NSPS: Non-methane hydrocarbon (NMHC) + NOx emissions shall not exceed 6.4 g/kW-hr.

OH-0368	PALLAS NITROGEN LLC	PALLAS NITROGEN LLC	OH	04/19/2017 ACT	Emergency Fire Pump Diesel Engine (P008)	17.21	Diesel fuel	460 HP - 343 kW Emergency Fire Pump Diesel Engine	Nitrogen Oxides (NOx)	P	good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII	0.3	LB/H		BACT-PSD	NSPS	U	0	U	0.02	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 0.4 g/kW-hr. NSPS: Non-methane hydrocarbon (NMHC) + NOx emissions shall not exceed 4.0 g/kW-hr (3.0 g/hp-hr).
OH-0368	PALLAS NITROGEN LLC	PALLAS NITROGEN LLC	OH	04/19/2017 ACT	Emergency Generator (P009)	17.11	Diesel fuel	5,000 HP â€“ 3,729 kW Emergency Generator Diesel Engine	Nitrogen Oxides (NOx)	P	good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII	5.5	LB/H		BACT-PSD	NSPS	U	0	U	0.3	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 0.67 g/kW-hr. NSPS limit is NMHC + NOx emissions shall not exceed 6.4 g/kW-hr (3.0 g/hp-hr).
OH-0370	TRUMBULL ENERGY CENTER	TRUMBULL ENERGY CENTER	OH	09/07/2017 ACT	Emergency generator (P003)	17.11	Diesel fuel	Emergency Generator 1000 kW (electrical), 1,140 kW (mechanical), 1,529 hp	Nitrogen Oxides (NOx)	P	State-of-the-art combustion design	16.07	LB/H		BACT-PSD	NSPS	U	0	U	4.02	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 6.4 g/kW-hr. NSPS limit is Non-methane hydrocarbon (NMHC) + NOx emissions shall not exceed 6.4 g/kW-hr.
OH-0370	TRUMBULL ENERGY CENTER	TRUMBULL ENERGY CENTER	OH	09/07/2017 ACT	Emergency fire pump engine (P004)	17.21	Diesel fuel	Emergency Fire Pump 300 hp (224 kW mechanical)	Nitrogen Oxides (NOx)	P	State-of-the-art combustion design	1.97	LB/H		BACT-PSD	NSPS	U	0	U	0.49	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 4.0 g/kW-hr. NSPS: Non-methane hydrocarbon (NMHC) + NOx emissions shall not exceed 4.0 g/kW-hr.
OH-0372	OREGON ENERGY CENTER	OREGON ENERGY CENTER	OH	09/27/2017 ACT	Emergency generator (P003)	17.11	Diesel fuel	1,000 kWe (1,140 kW mechanical) emergency diesel-fired generator	Nitrogen Oxides (NOx)	P	State-of-the-art combustion design	16.1	LB/H		BACT-PSD	NSPS	U	0	U	4.02	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 6.4 g/kW-hr (4.8 g/hp-hr). NSPS: Non-methane hydrocarbon (NMHC) + NOX emissions shall not exceed 6.4 g/kW-hr.

OH-0372	OREGON ENERGY CENTER	OREGON ENERGY CENTER	OH	09/27/2017 ACT	Emergency fire pump engine (P004)	17.21	Diesel fuel	300 hp emergency diesel-fired fire pump	Nitrogen Oxides (NOx)	P	State-of-the-art combustion design	1.97	LB/H		BACT-PSD	NSPS	U	0	U	0.49	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit is 4.0 g/kW-hr (3.0 g/hp-hr). NSPS is Non-methane hydrocarbon (NMHC) + NOX emissions shall not exceed 4.0 g/kW-hr (3.0 g/hp-hr).
OH-0374	GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	10/23/2017 ACT	Emergency Generators (2 identical, P004 and P005)	17.11	Diesel fuel	Two identical Emergency Generators; 1,645 kW (2,206 HP) emergency diesel-fired generator to provide on-site emergency power capabilities independent of the utility grid. Throughputs and limits are for a single generator except as noted.	Nitrogen Oxides (NOx)	P	the meet the emissions standards in 40 CFR 89.112 and 89.113 pursuant to 40 CFR 60.4205(b) and 60.4202(a)(2) . Good combustion practices per the manufacturer â€™s operating manual.	23.21	LB/H	NMHC +NOX. SEE NOTES.	BACT-PSD	NSPS	U	0	U	1.16	T/YR	NMHC+ NOX. SEE NOTES.	Non-methane hydrocarbon plus nitrogen oxides (NMHC+NOx) emissions shall not exceed 6.40 g/kW-hour (4.77 G/BHP-H), 23.21 pounds per hour and 1.16 tons per rolling, 12-month period.
OH-0374	GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	10/23/2017 ACT	Emergency Fire Pump (P006)	17.21	Diesel fuel	410 HP emergency diesel-fired fire pump to provide on-site firefighting capabilities independent of the utility grid	Nitrogen Oxides (NOx)	P	Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII. Good combustion practices per the manufacturer â€™s operating manual	2.7	LB/H	NMHC +NOX. SEE NOTES.	BACT-PSD	NSPS	U	0	U	0.14	T/YR	NMHC+ NOX. SEE NOTES.	Nonmethane hydrocarbons plus nitrogen oxides (NMHC+NOx) emissions shall not exceed 4.0 g/kW-hour (3.0 g/bhp-h), 2.70 pounds per hour and 0.14 ton per rolling, 12-month period.

OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	11/07/2017 ACT	Emergency Diesel Generator Engine (P001)	17.11	Diesel fuel	1,645 kW (2,206 HP) emergency diesel-fired generator to provide on-site emergency power capabilities independent of the utility grid.	Nitrogen Oxides (NOx)	P	Good combustion design	24.71	LB/H	NMHC +NOX. SEE NOTES.	BACT-PSD	NSPS	U	0	U	1.24	T/YR	NMHC+ NOX. SEE NOTES.	Non-methane hydrocarbon plus nitrogen oxides (NMHC+NOx) emissions shall not exceed 6.40 g/kW-h (4.8 g/hp-h), 24.71 lb/h and 1.24 t/yr per rolling, 12-month period.
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	11/07/2017 ACT	Emergency Diesel Fire Pump Engine (P002)	17.11	Diesel fuel	700 hp emergency diesel-fired fire pump to provide on-site firefighting capabilities independent of the utility grid	Nitrogen Oxides (NOx)	P	Good combustion design	4.97	LB/H	NMHC +NOX. SEE NOTES.	BACT-PSD	NSPS	U	0	U	0.25	T/YR	NMHC+ NOX. SEE NOTES.	Nonmethane hydrocarbons plus nitrogen oxides (NMHC+NOx) emissions shall not exceed 4.0 g/kW-hour, 4.97 pounds per hour and 0.25 ton per rolling, 12-month period. NSPS: Non-methane hydrocarbon (NMHC) + NOX emissions shall not exceed 4.0 g/kW-hr (3.0 g/hp-hr).
OH-0376	IRONUNITS LLC - TOLEDO HBI	IRONUNITS LLC - TOLEDO HBI	OH	02/09/2018 ACT	Emergency diesel-fueled fire pump (P006)	17.21	Diesel fuel	250 hp emergency diesel-fueled fire pump	Nitrogen Oxides (NOx)	P	Comply with NSPS 40 CFR 60 Subpart IIII	1.6	LB/H		BACT-PSD	NSPS	U	0	U	0.41	T/YR	PER ROLLING 12 MONTH PERIOD	NOx Standard limit is 4.0 g/kW-hr (3.0 g/hp-hr). NSPS: Non-methane hydrocarbon (NMHC) + NOX emissions shall not exceed 4.0 g/kW-hr (3.0 g/hp-hr).
OH-0376	IRONUNITS LLC - TOLEDO HBI	IRONUNITS LLC - TOLEDO HBI	OH	02/09/2018 ACT	Emergency diesel-fired generator (P007)	17.11	Diesel fuel	2,000 kW (2,682 hp) emergency diesel-fired generator	Nitrogen Oxides (NOx)	P	Comply with NSPS 40 CFR 60 Subpart IIII	28.2	LB/H		BACT-PSD	NSPS	U	0	U	7.05	T/YR	PER ROLLING 12 MONTH PERIOD	NOx Standard limit is 6.4 g/kW-hr (4.8 g/hp-hr). NSPS: Non-methane hydrocarbon (NMHC) + NOX emissions shall not exceed 6.4 g/kW-hr (4.8 g/hp-hr).

OH-0377	HARRISON POWER	HARRISON POWER	OH	04/19/2018 ACT	Emergency Diesel Generator (P003)	17.11	Diesel fuel	1,387 KW (1,860 HP) emergency diesel-fired generator	Nitrogen Oxides (NOx)	P	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	19.68	LB/H	NMHC +NOX. SEE NOTES.	BACT-PSD	NSPS	U	0	U	0.98	T/YR	NMHC+ NOX. SEE NOTES.	All emissions limits are for Non-methane hydrocarbon (NMHC) + NOX emissions. 0.98 t/yr per rolling, 12-month period. NSPS: Non-methane hydrocarbon (NMHC) + NOX emissions shall not exceed 6.4 g/kW-hr (4.8 g/hp-hr).
OH-0377	HARRISON POWER	HARRISON POWER	OH	04/19/2018 ACT	Emergency Fire Pump (P004)	17.21	Diesel fuel	238.6 KW (320 HP) emergency diesel-fired firewater pump	Nitrogen Oxides (NOx)	P	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	2.12	LB/H	NMHC +NOX. SEE NOTES.	BACT-PSD	NSPS	U	0	U	0.11	T/YR	NMHC+ NOX. SEE NOTES.	All emissions limits are for Non-methane hydrocarbon (NMHC) + NOX emissions. 0.11 t/yr per rolling, 12-month period. NSPS: Non-methane hydrocarbon (NMHC) + NOX emissions shall not exceed 4.0 g/kW-hr (3.0 g/hp-hr).
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018 ACT	Firewater Pumps (P005 and P006)	17.21	Diesel fuel	Two identical Firewater Pumps 1 and 2; 300 kW (402 HP) emergency diesel-fired firewater pump engine. Limits are for single pump except as noted.	Nitrogen Oxides (NOx)	P	Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII and employ good combustion practices per the manufacturer â€™s operating manual	2.64	LB/H	SEE NOTES.	BACT-PSD	NSPS	U	0	U	0.13	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	Emission limits are for non-methane hydrocarbon plus nitrogen oxides (NMHC + NOx). Non-methane hydrocarbon plus nitrogen oxides (NMHC + NOx) emissions shall not exceed 4.0 g/kW-hour (3.0 g/HP-hour), 2.64 pounds per hour and 0.13 ton per rolling, 12-month period.

OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018 ACT	Emergency Diesel-fired Generator Engine (P007)	17.11	Diesel fuel	2,500 kW (3,353 HP) emergency diesel-fired generator engine	Nitrogen Oxides (NOx)	P	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer â€™s operating manual	37.41	LB/H	SEE NOTES.	BACT-PSD	NSPS	U	0	U	1.87	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	Emission limits are for non-methane hydrocarbon plus nitrogen oxides (NMHC + NOx). Non-methane hydrocarbon plus nitrogen oxides (NMHC + NOx) emissions shall not exceed 6.4 g/kW-hour (4.8 g/HP-hour), 37.41 pounds per hour and 1.87 tons per rolling, 12-month period.
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018 ACT	1,000 kW Emergency Generators (P008 - P010)	17.11	Diesel fuel	Three identical ECU Generators 1 to 3; 1,000 kW (1,341 HP) emergency diesel-fired generator engine. Limits are for single generator except as noted.	Nitrogen Oxides (NOx)	P	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer â€™s operating manual	14.96	LB/H	SEE NOTES.	BACT-PSD	NSPS	U	0	U	0.75	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	Emission limits are for non-methane hydrocarbon plus nitrogen oxides (NMHC + NOx). Non-methane hydrocarbon plus nitrogen oxides (NMHC + NOx) emissions shall not exceed 6.4 g/kW-hour (4.8 g/HP-hour), 14.96 pounds per hour and 0.75 ton per rolling, 12-month period.
OH-0379	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	02/06/2019 ACT	Black Start Generator (P007)	17.21	Diesel fuel	Black start generator, 158 HP diesel engine.	Nitrogen Oxides (NOx)	P	Tier IV engine Tier IV NSPS standards certified by engine manufacturer.	0.104	LB/H		BACT-PSD	NSPS	U	0	U	5.2	X10-3 T/YR		

OH-0379	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	02/06/2019 ACT	Emergency Generators (P005 and P006)	17.11	Diesel fuel	Two identical Emergency generators, 3131 HP diesel engines. Throughputs and limits are for one generator, except as noted.	Nitrogen Oxides (NOx)	P	Tier IV engine Tier IV NSPS standards certified by engine manufacturer.	3.45	LB/H		BACT-PSD	NSPS	U	0	U	0.17	T/YR		NSPS: 4.8 grams NOx + NMHC/bhp-hr
OH-0383	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	07/17/2020 ACT	Diesel-fired emergency fire pumps (2) (P009 and P010)	17.11	Diesel fuel	Two identical fire pump 3131 HP diesel engines. Throughputs and limits are for one engine, except as noted.	Nitrogen Oxides (NOx)	P	Tier IV NSPS standards certified by engine manufacturer.	0			BACT-PSD	NSPS	U	0	U	0			
OK-0154	MOORELAND GENERATING STA	WESTERN FARMERS ELECTRIC COOPERATIVE	OK	07/02/2013 ACT	DIESEL-FIRED EMERGENCY GENERATOR ENGINE	17.11	DIESEL	<100 HR/YR OPERATION.	Nitrogen Oxides (NOx)	P	COMBUSTION CONTROL	0.011	LB/HP-HR		BACT-PSD	NSPS	U	0	U	0			
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	MOXIE ENERGY LLC	PA	10/10/2012 ACT	Emergency Generator	17.11	Diesel	The emergency generator will be restricted to operate not more than 100 hr/yr.	Nitrogen Oxides (NOx)	N		4.93	G/B-HP-H		OTHER CASE-BY-CASE	OTHER	U	0	U	0			
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	MOXIE ENERGY LLC	PA	10/10/2012 ACT	Fire Pump	17.21	Diesel	The fire pump will be restricted to operate not more than 100 hr/yr.	Nitrogen Oxides (NOx)	N		2.6	G/B-HP-H		OTHER CASE-BY-CASE	OTHER	U	0	U	2.6	LB/H		Expressed as NO2. Other Limit: 0.13 T/YR
PA-0291	HICKORY RUN ENERGY STATION	HICKORY RUN ENERGY LLC	PA	04/23/2013 ACT	EMERGENCY FIREWATER PUMP	17.21	LOW SULFUR DISTILLATE	EMERGENCY FIREWATER PUMP (450 BHP)	Nitrogen Oxides (NOx)	N		1.86	LB/H		OTHER CASE-BY-CASE	OTHER	U	0	U	0.09	T/YR	12 MONTH ROLLING TOTAL	
PA-0291	HICKORY RUN ENERGY STATION	HICKORY RUN ENERGY LLC	PA	04/23/2013 ACT	EMERGENCY GENERATOR	17.11	Ultra Low sulfur Distillate	EMERGENCY GENERATOR (1,135 BHP - 750 KW)	Nitrogen Oxides (NOx)	N		9.89	LB/H		OTHER CASE-BY-CASE	OTHER	U	0	U	0.49	T/YR	12-MONTH ROLLING TOTAL	
PA-0309	NNA ENERGY CTR/JESSUP	NNA ENERGY CENTER, LLC	PA	12/23/2015 ACT	Fire pump engine	17.21	Ultra-low sulfur diesel		Nitrogen Oxides (NOx)	N		3	GM/HP-HR		LAER		U	0	U	0.05	TONS	12-MONTH ROLLING BASIS	

PA-0309	LACKAWANNA ENERGY CTR/JESSU	LACKAWANNA ENERGY CENTER,	PA	12/23/2015 ACT	2000 kW Emergency Generator	17.11	Ultra-low sulfur Diesel	To allow maintenance of vital plant loads during power outages or maintenance of the	Nitrogen Oxides (NOx)	N		5.45	GM/HP-HR		LAER		U	0	U	0.81	TONS	12-MONTH ROLLING BASIS	
PA-0310	CPV FAIRVIEW ENERGY CENTER	CPV FAIRVIEW, LLC	PA	09/02/2016 ACT	Emergency Generator Engines	17.11	ULSD	(2) 1500 kW emergency diesel genset. Emission limitations are for each genset and fuel is restricted to ULSD (15 ppm) and each is restricted to 100 hrs on a 12-month rolling basis.	Nitrogen Oxides (NOx)	N		4.8	G/BHP-HR		LAER	NSPS	U	0	U	0			
PA-0310	CPV FAIRVIEW ENERGY CENTER	CPV FAIRVIEW, LLC	PA	09/02/2016 ACT	Emergency Fire Pump Engine	17.21	ULSD	Sulfur content of diesel fuel shall not exceed 15 ppm, operation of engine shall not exceed 100 hr on a 12-month rolling basis.	Nitrogen Oxides (NOx)	N		3	G/BHP-HR		LAER	NSPS	U	0	U	0			
PA-0311	MOXIE FREEDOM GENERATION PLANT	MOXIE FREEDOM LLC	PA	09/01/2015 ACT	Emergency Generator	17.11		Sulfur content of the diesel fuel combusted by the emergency diesel generator shall not exceed 15 ppm. Shall maintain and operate the source in accordance with good engineering practice.	Nitrogen Oxides (NOx)	N		4.93	G/HP-HR		LAER	NSPS	U	0	U	0.4	TPY	12-MONTH ROLLING BASIS	
PA-0311	MOXIE FREEDOM GENERATION PLANT	MOXIE FREEDOM LLC	PA	09/01/2015 ACT	Fire Pump Engine	17.11	diesel	Sulfur content of the diesel fuel combusted by the fire engine pump shall not exceed 15 ppm. Shall maintain and operate the source in accordance with good	Nitrogen Oxides (NOx)	N		3	G/HP-HR		LAER	NSPS	U	0	U	0.08	TPY	12-MONTH ROLLING BASIS	
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	ENERGY ANSWERS ARECIBO, LLC	PR	04/10/2014 ACT	Emergency Diesel Fire Pump	17.21	ULSD Fuel Oil #2	The Emergency Fire Pump is rated at 335 BHP and limited to 500 hr/yr (emergency operations and testing and maintenance, combined).	Nitrogen Oxides (NOx)	N		2.85	G/B-HP-H		BACT-PSD		U	0	U	2.1	LB/H		

PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	ENERGY ANSWERS ARECIBO, LLC	PR	04/10/2014 ACT	Emergency Diesel Generator	17.11	ULSD Fuel oil # 2	Emergency Generator is rated at 670 BHP and is limited to 500 hr per year (emergency and testing and maintenance, combined)	Nitrogen Oxides (NOx)	N		2.85	G/B-HP-H		BACT-PSD		U	0	U	4.2	LB/H		
TX-0671	PROJECT JUMBO	M&G RESINS USA, LLC	TX	12/01/2014 ACT	Engines	17.11	ultra low sulfur diesel fuel	fired generators proposed. Each engine will be 4000 kW. Ultra low sulfur fuel is burned in the engines to meet the sulfur requirement of 15 ppm in 40CFR80.510(b). Each emergency engine is being permitted for maintenance and testing for maximum 100 hrs/yr. They are not being permitted for the actual emergency emissions	Nitrogen Oxides (NOx)	P	Each emergency generator's emission factor is based on EPA's Tier 2 standards at 40CFR89.112 for NOx	5.43	G/KW-H		BACT-PSD	NSPS	U	0	U	2.39	T/YR		

TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	BASF	TX	04/01/2015 ACT	Emergency Diesel Generator	17.11	Diesel	generator (EPN 17-1-4) at the site is diesel fired and rated at 1500 horsepower (hp). Lowest Achievable Emission Rates (LAER) for nitrogen oxides (NOx) is the use of a 40 Code Federal Rules (CFR) Part 89 Tier 2 engine and limited hours of operation. Emissions from the engine shall not exceed 0.0218 grams per horsepower-hour (g/hp-hr) of nitrogen oxides (NOx). The engine is limited to 52 hours per year of non-emergency operation. Emissions from the engine shall not exceed 0.01256 g/hp hr of carbon monoxide (CO). The fuel for the engine is limited to 15 parts per million sulfur by weight (ultra-low sulfur diesel).	Nitrogen Oxides (NOx)	P	Minimized hours of operations Tier II engine	0.0218	G/HP HR		LAER	NSPS , MACT	N	0	U	0.35	TPY		
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	MOTIVA ENTERPRISE LLC	TX	02/06/2020 ACT	Emergency generator	17.11	DIESEL	Ultra-low sulfur diesel containing no more than 15 ppmw total sulfur	Nitrogen Oxides (NOx)	P	exhaust emission standards specified in 40 CFR Â§ 1039.101, limited to 100 hours per year of non-emergency operation	0			BACT-PSD	NSPS , MACT	N	0	U	0			NSPS IIII, MACT ZZZZ

TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	MOTIVA ENTERPRISE LLC	TX	02/06/2020 ACT	Emergency firewater pumps	17.11		Ultra-low sulfur diesel containing no more than 15 ppmw total sulfur	Nitrogen Oxides (NOx)	P	Tier 3 exhaust emission standards specified in 40 CFR Â§ 89.112, limited to 100 hours per year of non-emergency	0			BACT-PSD	NSPS , MACT	N	0	U	0			
TX-0879	MOTIVA PORT ARTHUR TERMINAL	MOTIVA ENTERPRISES LLC	TX	02/19/2020 ACT	Emergency Firewater Engine	17.11	Ultra-low sulfur diesel	Ultra-low sulfur diesel containing no more than 15 ppmw total sulfur	Nitrogen Oxides (NOx)	P	Meeting the requirements of 40 CFR Part 60, Subpart IIII. Firing ultra-low sulfur diesel fuel (no more than 15 ppm sulfur by weight). Limited to 100 hrs/yr of non-emergency operation. Have a non-resettable runtime meter.	0			BACT-PSD	NSPS , MACT	N	0	U	0			NSPS IIII MACT ZZZZ
TX-0888	ORANGE POLYETHYLENE PLANT	CHEVRON PHILLIPS CHEMICAL COMPANY LP	TX	04/23/2020 ACT	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	17.11	Ultra-low Sulfur Diesel		Nitrogen Oxides (NOx)	P	well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.	0			BACT-PSD	NSPS , MACT	N	0	U	0			

TX-0904	MOTIVA POLYETHY LENE MANUFAC TURING COMPLEX		TX	09/09/202 0 ACT	EMERGEN CY GENERATO R	17.11	ULTRA LOW SULFU R DIESEL		Nitrogen Oxides (NOx)	P	100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR Â§ 1039.101	0			BACT-PSD		N	0	U	0			
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	DIAMOND GREEN DIESEL	TX	09/16/202 0 ACT	EMERGEN CY GENERATO R	17.11	ULTRA LOW SULFU R DIESEL		Nitrogen Oxides (NOx)	P	limited to 100 hours per year of non-emergency operation	0			BACT-PSD		N	0	U	0			
TX-0933	NACERO PENWELL FACILITY	NACERO TX 1 LLC	TX	11/17/202 1 ACT	Emergency Generators	17.11	Ultra-low sulfur diesel (no more than 15		Nitrogen Oxides (NOx)	P	limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR Â§ 1039.101) exhaust emission	0			BACT-PSD		N	0	U	0			
VA-0325	GREENSVIL LE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	06/17/201 6 ACT	DIESEL-FIRED EMERGEN CY GENERATO R 3000 kW (1)	17.11	DIESEL FUEL		Nitrogen Oxides (NOx)	P	Good Combustion Practices/Ma intenance	6.4	G/KW	PER HR	N/A		U	0	U	10.6	T/YR	12 MO ROLLIN G TOTAL	
VA-0325	GREENSVIL LE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	06/17/201 6 ACT	DIESEL-FIRED WATER PUMP 376 bph (1)	17.21	DIESEL FUEL	FWP-1: 104.0 tons/year (12-month rolling total)	Nitrogen Oxides (NOx)	P	Good Combustion Practices/Ma intenance	0			N/A		U	0	U	0			EMISSION LIMIT: 1 3.0 g/hp-hr NOx + NMHC (4.0 g/kW-hr NOx + NMHC)

VA-0328	C4GT, LLC	NOVI ENERGY	VA	04/26/2018 ACT	Emergency Diesel GEN	17.11	Ultra Low Sulfur Diesel		Nitrogen Oxides (NOx)	P	good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	4.8	G/HP H		BACT-PSD	NSPS , SIP	N	0	N	9.6	T/YR	12 MO ROLLING AV	NOX + NMHC
VA-0328	C4GT, LLC	NOVI ENERGY	VA	04/26/2018 ACT	Emergency Fire Water Pump	17.21	Ultra Low Sulfur Diesel	315 BHP	Nitrogen Oxides (NOx)	P	Good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	3	G/HP-HR		BACT-PSD	SIP , NSPS	U	0	N	0			
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	VA	06/24/2019 ACT	Emergency Diesel Generator - 300 kW	17.11	Ultra Low Sulfur Diesel		Nitrogen Oxides (NOx)	P	good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	4.8	G/HP-H		BACT-PSD	NSPS , SIP	N	0	N	11.7	T/YR	12 MO ROLLING AVG	Emission Limit 3: 4.8 G/HP - HR

VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	VA	06/24/2019 ACT	Emegency Fire Water Pump	17.21	Ultra Low Sulfur Diesel		Nitrogen Oxides (NOx)	P	good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	3	G/HP-HR		BACT-PSD	NSPS , SIP	N	0	N	0.7	T/YR		
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT		WI	04/24/2018 ACT	Diesel-Fired Emergency Generators	17.11	Diesel Fuel	Ten, 2,180kW Diesel-Fired Emergency Generators.	Nitrogen Oxides (NOx)	P	The Use of Ultra-Low Sulfur Fuel and Good Combustion Practices	5.36	G/KWH		BACT-PSD	NSPS , NESHAP	N	0	U	0			BACT is Total hours of operation for each generator is 200 hours over a 12 month period. Ultra-low sulfur fuel contains less than 15 ppm sulfur. Good combustion practices are defined as maintaining the stationary compression ignition internal combustion engine according to each manufacturerâ€™s emission-related instructions.

WI-0286	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	SIO INTERNATIONAL	WI	04/24/2018 ACT	P42 -Diesel Fired Emergency Generator	17.11	Diesel Fuel	Maximum Continuous Rating: 1,750 kW or 2,346 bhp	Nitrogen Oxides (NOx)	P	Good Combustion Practices, The Use of an Engine Turbocharger and Aftercooler.	5.36	G/KWH		BACT-PSD	NSPS , NESHAP	N	0	U	0			BACT is Good combustion practices are defined as maintaining the stationary compression ignition internal combustion engine according to the manufacturerâ€™s emission-related written instructions. The total hours of operation of the emergency generator may not exceed 200 hours during each consecutive 12-month period.
*WI-0300	NEMADJI TRAIL ENERGY CENTER	NEMADJI TRAIL ENERGY CENTER	WI	09/01/2020 ACT	Emergency Diesel Fire Pump (P06)	17.21	Diesel		Nitrogen Oxides (NOx)	P	Operation limited to 500 hours/year and shall be operated and maintained according to the manufacturerâ€™s recommendations.	3	G/HP-H		BACT-PSD		U	0	U	0			
*WI-0300	NEMADJI TRAIL ENERGY CENTER	NEMADJI TRAIL ENERGY CENTER	WI	09/01/2020 ACT	Emergency Diesel Generator (P07)	17.11	Diesel		Nitrogen Oxides (NOx)	P	Operation limited to 500 hours/year and operate and maintain according to the manufacturerâ€™s recommendations.	4.8	G/HP-H		BACT-PSD		U	0	U	0			

WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	MOUNDSVILLE POWER, LLC	WV	11/21/2014 ACT	Emergency Generator	17.11	Diesel	Nominal 1,500 kW. Limited to 100 hours/year.	Nitrogen Oxides (NOx)	N		0			BACT-PSD	NSPS	U	0	U	0			
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	MOUNDSVILLE POWER, LLC	WV	11/21/2014 ACT	Fire Pump Engine	17.21	Diesel	Limited to 100 Hours/year.	Nitrogen Oxides (NOx)	N		0			BACT-PSD	NSPS	U	0	U	0			
WV-0027	INWOOD	KNAUF INSULATION INC.	WV	09/15/2017 ACT	Emergency Generator - ESDG14	17.11	ULSD	Used to supply power to the facility in the event of power loss	Nitrogen Oxides (NOx)	P	Engine Design	4.77	G/HP-HR		BACT-PSD	NSPS , MACT	U	0	U	0			Engine is limited to 100 hours of non-emergency use per year.
*WV-0033	MAIDSVILLE	MOUNTAIN STATE CLEAN ENERGY, LLC	WV	01/05/2022 ACT	Emergency Generator	17.11	ULSD	4SLB Diesel-Fired Emergency Engine - Subpart IIII	Nitrogen Oxides (NOx)	P	Combustion Control (retarded timing and/or lean burn)	24.6	LB/HR		BACT-PSD	NSPS	N	0	U	6.4	G/BKW	NMHC+ NOX	Certified Engine
*WV-0033	MAIDSVILLE	MOUNTAIN STATE CLEAN ENERGY, LLC	WV	01/05/2022 ACT	Fire Water Pump	17.11	ULSD	4SLB Diesel-Fired Emergency Engine - Subpart IIII.	Nitrogen Oxides (NOx)	P	Combustion control (retarded timing and/or lean burn)	1.59	LB/HR		BACT-PSD	NSPS	U	0	U	4	G/BKW		Certified Engine

RBLCID	FACILITY_NAME	CORPORATE_OR_COMPANY_NAME	FACILITY_STATE	PERMIT_ISSUANCE_DATE	PROCESS_NAME	PROCCESS_TYPE	PRIMARY_FUEL	PROCESS_NOTES	POLLUTANT	CONTROL_METHOD_CODE	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT	EMISSION_LIMIT_1_AVG_TIME_CONDITION	CASE-BY-CASE_BASIS	OTHER_APPLICABLE_REQUIREMENTS	OTHER_FACTORS	PERCENT_EFFICIENCY	COMPLIANCE_VERIFIED	EMISSION_LIMIT_2	EMISSION_LIMIT_2_UNIT	EMISSION_LIMIT_2_AVGERAGE_TIME_CONDITION	POLLUTANT_COMPLIANCE_NOTES
AK-0082	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	01/23/2015 ACT	Emergency Camp Generators	17.11	Ultra Low Sulfur Diesel	Three 2,695 hp ULSD-fired Standby Camp Generator Engines.	Nitrogen Oxides (NOx)	N		4.8	GRAMS/HP-H		BACT-PSD		U	0	U	0			
AK-0082	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	01/23/2015 ACT	Fine Water Pumps	17.11	Ultra Low Sulfur Diesel	Two ULSD-fired 610 hp Fine Water Pumps	Nitrogen Oxides (NOx)	N		3	GRAMS/HP-H		BACT-PSD		U	0	U	0			
AK-0082	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	01/23/2015 ACT	Bulk Tank Generator Engines	17.11	Ultra Low Sulfur Diesel	Two ULSD-fired 891 hp Bulk Tank Storage Area Generator Engines	Nitrogen Oxides (NOx)	N		4.8	GRAMS/HP-H		BACT-PSD		U	0	U	0			
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	06/30/2017 ACT	Black Start and Emergency Internal Cumbustion Engines	17.11	Diesel	Two (2) 600 kWe black start diesel generators and four (4) 1,500 kWe emergency diesel generators.	Nitrogen Oxides (NOx)	P	Good Combustion Practices	8	G/KW-HR	3-HOUR AVERAGE	BACT-PSD	NSPS	U	0	U	0			8.0 g/kW-hr includes NOx and VOC emissions. NSPS Subpart IIII engines.
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	06/30/2017 ACT	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	17.11	Diesel and Natural Gas	Twelve 17-MW Wartsila 18V50DF ULSD/Natural Gas-Fired Internal Combustion Engines. Each engine rated at: 143.5 MMBtu/hr on ULSD 141.4 MMBtu/hr on natural gas	Nitrogen Oxides (NOx)	B	Selective Catalytic Reduction (SCR) and Good Combustion Practices	0.53	G/KW-HR (ULSD)	3-HOUR AVERAGE	BACT-PSD		U	95	U	0.08	G/KW-HR (NATURAL GAS	3-HOUR AVERAGE	Potential NOx emissions of 85.9 tpy for each engine (EU 1-12).

AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	08/13/2020 ACT	One (1) Black Start Generator Engine	17.11	ULSD	EU 39 is a 4,060 hp diesel generator.	Nitrogen Oxides (NOx)	P	Good combustion practices, limit operation to 500 hours per year.	3.3	G/HP-HR	3-HOUR AVERAGE	BACT-PSD	NSPS , NESHAP	U	0	U	0			EU 39 is an EPA Tier 4 Final Engine. 3.3 g/hp-hr limit includes 25% not to exceed factor of safety.
AK-0088	LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	07/07/2022 ACT	Diesel Fire Pump Engine	17.11	Diesel	EU 11 is a 575 hp diesel fire pump engine which is required to meet E.F.s from Table 4 of NSPS Subpart IIII, which is the equivalent to EPA Nonroad Tier 3. BACT E.F.s include not to exceed factor of safety as identified in 40 CFR 1039.101(e).	Nitrogen Oxides (NOx)	P	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII	3.6	G/HP-HR		BACT-PSD	NSPS	U	0	U	500	HRS/YR		NOx emissions from diesel firewater pump engine EU 11 will not exceed 3.6 g/hp-hr @ 15% O2 (95% of NMHC + NOx from Table 4 of NSPS Subpart IIII, also equivalent to EPA Tier 3, includes 25% not to exceed factor of safety);
AL-0301	NUCOR STEEL TUSCALOOSA, INC.	NUCOR STEEL TUSCALOOSA, INC.	AL	07/22/2014 ACT	DIESEL FIRED EMERGENCY GENERATOR	17.11	DIESEL		Nitrogen Oxides (NOx)	N		0.015	LB/HP-H		BACT-PSD	NSPS , MACT	N	0	N	0			
*AL-0318	TALLADEGA SAWMILL	GEORGIA PACIFIC WOOD PRODUCTS, LLC	AL	12/18/2017 ACT	250 Hp Emergency CI, Diesel-fired RICE	17.11	Diesel	Emergency Only	Nitrogen Oxides (NOx)	N		0			N/A		U	0	U	0			
AL-0328	PLANT BARRY	ALABAMA POWER COMPANY	AL	11/09/2020 ACT	Diesel Emergency Engines	17.11	Diesel		Nitrogen Oxides (NOx)	N		3	GR/BHP-HR	NMHC + NOX	BACT-PSD	NSPS , SIP , OPERATING PERMIT	U	0	N	0			
AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	09/23/2019 ACT	Emergency Engines	17.11	Diesel		Nitrogen Oxides (NOx)	P	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.4	G/KW-H		BACT-PSD		U	0	U	0			

AR-0163	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	06/09/2019 ACT	Emergency Engines	17.11	Diesel	The emergency generators are diesel fired generators which provide electrical power in the event of power failure.	Nitrogen Oxides (NOx)	P	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	4.86	G/KW-HR		BACT-PSD		U	0	U	0			
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	09/16/2014 ACT	Main Propulsion Generator Diesel Engines	17.11	Diesel	Four 1998 Wartsila 18V32LNE 9910 hp and Two 1998 Wartsila 12V32LNE 6610 hp	Nitrogen Oxides (NOx)	B	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	12.7	G/KW-H	ROLLING 24 HOUR AVERAGE	BACT-PSD	OPERATING PERMIT	U	0	U	0			
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	09/16/2014 ACT	Emergency Diesel Engine	17.11	Diesel	1998 Wartsila 6R32LNE	Nitrogen Oxides (NOx)	B	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	0			BACT-PSD	OPERATING PERMIT	U	0	U	0			

FL-0350	ANADARKO PETROLEUM, INC DIAMOND BLACKHAWK DRILLING PROJECT	ANADARKO PETROLEUM, INC.	FL	12/31/2014 ACT	Main Propulsion Generator Engines	17.11	Diesel	Six 2012 Hyundai-HiMsen 9H32/40V 6,035 hp and two 2012 Hyundai-HiMsen 18H32/40V diesel electric engines.	Nitrogen Oxides (NOx)	P	Use of good combustion practices based on the most recent manufacturer â€™s specifications issued for these engines at the time that the engines are operating under this permit	0			BACT-PSD	OPERATING PERMIT	U	0	U	0			DR-ME-01 through DR-ME-08 Operating at 50% Load and Above: 10.57 g/kw-hr on a rolling 24-hour average basis. DR-ME-01 through DR-ME-06 Operating Below 50% Load: 57.3 lb/hr on a rolling 24-hour average basis. DR-MR-07 and DR-ME-08 Operating Below 50% Load: 103.5 lb/hr on a rolling 24-hour average basis.
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	SHADY HILLS ENERGY CENTER, LLC	FL	07/27/2018 ACT	1,500 kW Emergency Diesel Generator	17.11	ULSD	The emergency generator will operate a combined total of 100 hr/yr for maintenance checks, and readiness testing, which includes a maximum 50 hr/yr for non-emergency operation.	Nitrogen Oxides (NOx)	P	Operate and maintain the engine according to the manufacturer's written instructions	6.4	G/KW-HOUR		BACT-PSD	NESHAP , NSPS	U	0	U	0			Standard equals Subpart IIII limit. Limit is for NOX and Non-Methane Hydrocarbons
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	SHADY HILLS ENERGY CENTER, LLC	FL	06/07/2021 ACT	1,500 kW Emergency Diesel Generator	17.11	ULSD	The emergency generator will operate a combined total of 100 hr/yr for maintenance checks, and readiness testing, which includes a maximum 50 hr/yr for non-emergency operation.	Nitrogen Oxides (NOx)	N		6.4	G/KW-HOUR	FOR NMHC +NOX	BACT-PSD	NSPS	U	0	U	0			
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	10/26/2012 ACT	Emergency Generator	17.11	diesel fuel	rated @ 2,000 KW	Nitrogen Oxides (NOx)	P	good combustion practices	6	G/KW-H	AVERAGE OF 3 STACK TEST RUNS	BACT-PSD		U	0	U	6.61	TONS/YR	ROLLING 12 MONTH TOTAL	

IL-0114	CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	09/05/2014 ACT	Emergency Generator	17.11	distillate fuel oil		Nitrogen Oxides (NOx)	P	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	0.67	G/KW-H		BACT-PSD		U	0	U	0			
IL-0129	CPV THREE RIVERS ENERGY CENTER	CPV THREE RIVERS, LLC	IL	07/30/2018 ACT	Emergency Engines	17.11	Ultra-low sulfur diesel	Two emergency engine-generators. One large emergency engine-generator, 1500 kW output, will provide emergency power to the plant. One small emergency engine-generator, 125 kW output, will provide emergency power to the switchyard. Fuel used in the emergency engines must meet the requirements of 40 CFR 80.510(b), pursuant to 40 CFR 60.4207(b).	Nitrogen Oxides (NOx)	N		0			LAER	NSPS	U	0	U	0			Limits of the NSPS, 40 CFR 60 Subpart IIII, are LAER for NOx. For the large engine: 6.4 g/kW-hr For the small engine: 4.0 g/kW-hr Permit limits are as follows: For the large engine: 23.0 lb/hr and 1.7 ton/yr For the small engine: 1.2 lb/hr and 0.09 ton/yr
IL-0130	JACKSON ENERGY CENTER	JACKSON GENERATION, LLC	IL	12/31/2018 ACT	Emergency Engine	17.11	Ultra-Low Sulfur Diesel	One large emergency engine-generator at the plant; one small emergency engine-generator at the switchyard. Fuel must meet the requirements at 40 CFR 80.510(b) pursuant to 40 CFR 60.4207(b)	Nitrogen Oxides (NOx)	N		6.4	G/KW-HR		LAER	NSPS	U	0	U	0			NSPS Subpart IIII limit of 6.4 g/kW-hr is LAER

*IL-0133	LINCOLN LAND ENERGY CENTER	LINCOLN LAND ENERGY CENTER (A/K/A EMBERCLEAR)	IL	07/29/2022 ACT	Emergency Engines	17.11	Ultra-Low Sulfur Diesel	Two engine-generators will power an electrical generator to provide power to critical equipment during power outages. Ultra-low sulfur diesel fuel (sulfur content <15 part per million (ppm)) will be used as fuel	Nitrogen Oxides (NOx)	N		6.4	GRAMS	KILOWATT-HOUR	BACT-PSD	NSPS	U	0	U	0			Limit 1 includes non-methane hydrocarbons (NMHC), i.e. NOx + NMHC, consistent with the NSPS, 40 CFR 60 Subpart IIII.
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	IN	12/03/2012 ACT	TWO (2) EMERGENCY DIESEL GENERATORS	17.11	DIESEL	THE TWO INTERNAL COMBUSTION ENGINES, IDENTIFIED AS EG01 AND EG02, EXHAUST THROUGH TWO (2) VENTS.	Nitrogen Oxides (NOx)	P	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	4.8	G/HP-H	3 HOURS	BACT-PSD			0		500	HOURS OF OPERATION	YEALRY	LIMIT ONE AND TWO ARE FOR EACH GENERATOR
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	IN	12/03/2012 ACT	EMERGENCY DIESEL GENERATOR	17.11	DIESEL	THIS ONE (1) INTERNAL COMBUSTION ENGINE, IDENTIFIED AS EG03, EXHAUSTS THROUGH ONE (1) VENT.	Nitrogen Oxides (NOx)	A	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	4.8	G/HP-H	3 HOURS	BACT-PSD			0		500	HOURS OF OPERATION	YEARLY	LIMIT ONE AND TWO ARE FOR EACH GENERATOR
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	06/04/2014 ACT	DIESEL FIRED EMERGENCY GENERATOR	17.11	NO. 2, DIESEL	ANNUAL OPERATING HOURS SHALL NOT EXCEED 500 HOURS. INSIGNIFICANT ACTIVITY WILL NOT BE TESTED.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES	4.46	G/BHP-H	3-HR AVERAGE	BACT-PSD		N	0		0			
IN-0179	OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	09/25/2013 ACT	DIESEL-FIRED EMERGENCY GENERATOR	17.11	NO. 2 FUEL OIL	ANNUAL HOURS OF OPERATION NOT TO EXCEED 200 HOURS.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES	4.46	G/B-HP-H	3-HR AVERAGE	BACT-PSD		N	0		0			ADD ON CONTROLS ARE NOT NORMALLY REQUIRED FOR LIMITED USE EMISSION UNITS.
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	06/04/2014 ACT	DIESEL FIRED EMERGENCY GENERATOR	17.11	NO. 2, DIESEL	ANNUAL OPERATING HOURS SHALL NOT EXCEED 500 HOURS. INSIGNIFICANT ACTIVITY WILL NOT BE TESTED.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES	4.46	G/B-HP-H	3-HR AVERAGE	BACT-PSD		N	0		0			
IN-0185	MAG PELLET LLC	MAG PELLET LLC	IN	04/24/2014 ACT	DIESEL FIRE PUMP	17.11	DIESEL		Nitrogen Oxides (NOx)	N		3	G/HP-H		BACT-PSD			0		500	H		RESTRICTED USE OF ONLY NATURAL GAS, THE USE OF GOOD COMBUSTION PRACTICES

IN-0263	MIDWEST FERTILIZER COMPANY LLC	MIDWEST FERTILIZER COMPANY LLC	IN	03/23/2017 ACT	EMERGENCY GENERATORS (EU014A AND EU-014B)	17.11	DISTILLATE OIL		Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES	4.42	G/HP-H EACH	3 HOUR AVERAGE	BACT-PSD		N	0		500	H/YR EACH		
IN-0317	RIVERVIEW ENERGY CORPORATION	RIVERVIEW ENERGY CORPORATION	IN	06/11/2019 ACT	Emergency generator EU-6006	17.11	Diesel		Nitrogen Oxides (NOx)	P	Tier II diesel engine	6.4	G/KWH	TIER II NOX + NMHC LIMIT	BACT-PSD	NSPS , NESHAP	U	0	U	0			Unit shall use good combustion practices and energy efficiency as defined in the permit. 40 CFR 60, subpart IIII 40 CFR 63, subpart ZZZZ
IN-0317	RIVERVIEW ENERGY CORPORATION	RIVERVIEW ENERGY CORPORATION	IN	06/11/2019 ACT	Emergency fire pump EU-6008	17.11	Diesel		Nitrogen Oxides (NOx)	P	Engine that complies with Table 4 to Subpart IIII of Part 60	4	G/KWH	COMBINED NOX + NMHC LIMIT	BACT-PSD	NSPS , NESHAP	U	0	U	0			Unit shall use good combustion practices and energy efficiency as defined in the permit. 40 CFR 60, subpart IIII 40 CFR 63, subpart ZZZZ
IN-0324	MIDWEST FERTILIZER COMPANY LLC	MIDWEST FERTILIZER COMPANY LLC	IN	05/06/2022 ACT	emergency generator EU 014a	17.11	distillate oil		Nitrogen Oxides (NOx)	N		4.42	G/HP-HR		BACT-PSD		U	0	U	500	HR/YR	TWELVE (12) CONSECUTIVE MONTH PERIOD	NOx emissions from the diesel-fired emergency generator (EU-014a) shall be controlled by exercising good combustion practices
IN-0324	MIDWEST FERTILIZER COMPANY LLC	MIDWEST FERTILIZER COMPANY LLC	IN	05/06/2022 ACT	fire water pump EU-015	17.11			Nitrogen Oxides (NOx)	N		2.83	G/HP-HR		BACT-PSD		U	0	U	500	HR/YR	TWELVE (12) CONSECUTIVE MONTH PERIOD	NOx emissions from the diesel-fired emergency fire water pump (EU-015) shall be controlled by good combustion practices

*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	KS	03/18/2013 ACT	Caterpillar C18DITA Diesel Engine Generator	17.11	No. 2 Distillate Fuel Oil		Nitrogen Oxides (NOx)	P	utilize efficient combustion/ design technology	14	LB/HR		BACT-PSD		U	0	U	0			
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 10-02 - North Water System Emergency Generator	17.11	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	N	0	U	0			prepare and maintain for EP 10-02, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 10-03 - South Water System Emergency Generator	17.11	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	N	0	U	0			prepare and maintain for EP 10-03, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 10-04 - Emergency Fire Water Pump	17.11	Diesel	Diesel emergency fire water pump used to provide emergency fire water supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	N	0	U	0			prepare and maintain for EP 10-04, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 10-07 - Air Separation Plant Emergency Generator	17.11	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	U	0	U	0			prepare and maintain for EP 10-07, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 10-01 - Caster Emergency Generator	17.11	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS	N	0	U	0			prepare and maintain for EP 10-01, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	04/19/2021 ACT	New Pumphouse (XB13) Emergency Generator #1 (EP 08-05)	17.11	Diesel	No controls.	Nitrogen Oxides (NOx)	P	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			prepare a good combustion and operations practices (GCOP) plan that defines, measures, and verifies the use of operational and design practices determined as BACT for minimizing emissions. Any revisions to the GCOP plan requested by the Division shall be made and the revisions shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Divisionâ€™s

KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	04/19/2021 ACT	Tunnel Furnace Emergency Generator (EP 08-06)	17.11	Diesel		Nitrogen Oxides (NOx)	P	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			prepare a good combustion and operations practices (GCOP) plan that defines, measures, and verifies the use of operational and design practices determined as BACT for minimizing emissions. Any revisions to the GCOP plan requested by the Division shall be made and the revisions shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Divisionâ€™s

KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	04/19/2021 ACT	Caster B Emergency Generator (EP 08-07)	17.11	Diesel		Nitrogen Oxides (NOx)	P	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			prepare a good combustion and operations practices (GCOP) plan that defines, measures, and verifies the use of operational and design practices determined as BACT for minimizing emissions. Any revisions to the GCOP plan requested by the Division shall be made and the revisions shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Divisionâ€™s

KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	04/19/2021 ACT	Air Separation Unit Emergency Generator (EP 08-08)	17.11	Diesel		Nitrogen Oxides (NOx)	P	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			prepare a good combustion and operations practices (GCOP) plan that defines, measures, and verifies the use of operational and design practices determined as BACT for minimizing emissions. Any revisions to the GCOP plan requested by the Division shall be made and the revisions shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Divisionâ€™s

LA-0288	LAKE CHARLES CHEMICAL COMPLEX	SASOL CHEMICALS (USA) LLC	LA	05/23/2014 ACT	Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)	17.11			Nitrogen Oxides (NOx)	P	Comply with 40 CFR 60 Subpart IIII; operate the engine in accordance with the engine manufacturerâ€™s instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	27.37	LB/HR	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	1.37	TPY	ANNUAL MAXIMUM	BACT is determined to be compliance with the limitations imposed by 40 CFR 60 Subpart IIII and its associated monitoring, recordkeeping, and reporting requirements; and operating the engine in accordance with the engine manufacturerâ€™s instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage. Limit NOx + NMHC to 6.4 g/kW-hr.
LA-0292	HOLBROOK COMPRESSOR STATION	CAMERON INTERSTATE PIPELINE LLC	LA	01/22/2016 ACT	Emergency Generators No. 1 & No. 2	17.11	Diesel		Nitrogen Oxides (NOx)	P	Good equipment design, proper combustion techniques, use of low sulfur fuel, and compliance with 40 CFR 60 Subpart IIII	14.16	LB/HR	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0.71	TPY	ANNUAL MAXIMUM	Emergency generators are also subject to a BACT limit of 1.51 lb NOx/MM Btu.

LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	SASOL CHEMICALS (USA) LLC	LA	05/23/2014 ACT	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, & 1202)	17.11	Diesel	Non-emergency use is limited to 100 hours per year.	Nitrogen Oxides (NOx)	P	Compliance with 40 CFR 60 Subpart IIII; operating the engine in accordance with the engine manufacturerâ€™s instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage.	27.37	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT , NSPS	U	0	U	1.37	TPY	ANNUAL MAXIMUM	NOx + NMHC limit is 6.40 g/kW-hr. BACT is determined to be compliance with the limitations imposed by 40 CFR 60 Subpart IIII and its associated monitoring, recordkeeping, and reporting requirements; and operating the engine in accordance with the engine manufacturerâ€™s instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage.
LA-0305	LAKE CHARLES METHANOL FACILITY	LAKE CHARLES METHANOL, LLC	LA	06/30/2016 ACT	Diesel Engines (Emergency)	17.11	Diesel		Nitrogen Oxides (NOx)	P	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	U	0	U	0			
LA-0307	MAGNOLIA LNG FACILITY	MAGNOLIA LNG, LLC	LA	03/21/2016 ACT	Diesel Engines	17.11	Diesel	Water Pumps (2 units) = 355 hp Tank Deluge Pumps (2 units) = 800 hp Generator = 1340 hp	Nitrogen Oxides (NOx)	P	good combustion practices, Use ultra low sulfur diesel, and comply with 40 CFR 60 Subpart IIII	0			BACT-PSD		U	0	U	0			

LA-0308	MORGAN CITY POWER PLANT	LOUISIANA ENERGY AND POWER AUTHORITY (LEPA)	LA	09/26/2013 ACT	2000 KW Diesel Fired Emergency Generator Engine	17.11	Diesel		Nitrogen Oxides (NOx)	P	Good combustion and maintenance practices, and compliance with NSPS 40 CFR 60 Subpart IIII	33.07	LB/H	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	U	0	U	1.38	T/YR	ANNUAL MAXIMUM	
LA-0309	BENTELER STEEL TUBE FACILITY	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	LA	06/04/2015 ACT	Emergency Generator Engines	17.11	Diesel		Nitrogen Oxides (NOx)	P	Complying with 40 CFR 60 Subpart IIII	6.4	G/KW-HR		BACT-PSD		U	0	U	0			
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	LA	06/30/2017 ACT	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	17.11	Diesel	Operating hour limit: 100 hr/yr	Nitrogen Oxides (NOx)	P	Compliance with NSPS Subpart IIII	6.6	LB/HR		BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0			Limit: 3.84 g/hp-hr
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	LA	06/30/2017 ACT	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	17.11	Diesel	Operating hours limit: 100 hr/yr.	Nitrogen Oxides (NOx)	P	Compliance with NSPS Subpart IIII	19.23	LB/HR		BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0			Limit: 4.93 g/hp-hr
LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	LA	08/31/2016 ACT	SCPS Emergency Diesel Generator 1	17.11	Diesel		Nitrogen Oxides (NOx)	B	Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel).	27.34	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	6.84	T/YR	ANNUAL MAXIMUM	BACT Limit = 4.8 G/BHP-HR (NMHC + NOx)

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*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	05/23/2014 ACT	Emergency Diesel Generator 1	17.11	Diesel		Nitrogen Oxides (NOx)	P	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	52.58	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	2.63	T/YR	ANNUAL MAXIMUM	BACT Limit = 4.80 G/BHP-H (6.4 G/KW-H) (12-Month Rolling Average)
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	05/23/2014 ACT	Emergency Diesel Generator 2	17.11	Diesel		Nitrogen Oxides (NOx)	P	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	52.58	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	2.63	T/YR	ANNUAL MAXIMUM	BACT Limit = 4.80 G/BHP-H (6.4 G/KW-H) (12-Month Rolling Average)
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	05/23/2014 ACT	Fire Pump Diesel Engine 1	17.11	Diesel		Nitrogen Oxides (NOx)	P	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.6	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0.23	T/YR	ANNUAL MAXIMUM	BACT Limit = 4.80 G/BHP-H (6.40 G/KW-H) (12-Month Rolling Average)
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	05/23/2014 ACT	Fire Pump Diesel Engine 2	17.11	Diesel		Nitrogen Oxides (NOx)	P	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.6	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0.23	T/YR	ANNUAL MAXIMUM	BACT Limit = 4.8 G/BHP-H (6.40 G/KW-H) (12-Month Rolling Average)
LA-0316	CAMERON LNG FACILITY	CAMERON LNG LLC	LA	02/17/2017 ACT	emergency generator engines (6 units)	17.11	diesel		Nitrogen Oxides (NOx)	P	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	U	0	U	0			
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	LA	12/22/2016 ACT	Emergency Generator Engines (4 units)	17.11	Diesel	I-GDE-1201, II-GDE-1201 = 2346 hp I-GDE-1202 = 755 hp I-GDE-1203 = 1193 hp	Nitrogen Oxides (NOx)	P	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			BACT = LAER (Permit 0180-00210-V4, dated 12/22/2016)
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	LA	12/22/2016 ACT	Firewater pump Engines (4 units)	17.11	diesel		Nitrogen Oxides (NOx)	P	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			BACT = LAER (Permit 0180-00210-V4, dated 12/22/2016)
LA-0318	FLOPAM FACILITY	FLOPAM, INC.	LA	01/07/2016 ACT	Diesel Engines	17.11			Nitrogen Oxides (NOx)	P	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD		U	0	U	0			

LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	LA	01/09/2017 ACT	Fire Water Diesel Pump No. 3 Engine	17.11	Diesel Fuel	Emergency engine with a limit of 100 hours/yr on operating hours for ready testing.	Nitrogen Oxides (NOx)	P	Proper operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	U	0	U	0			
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	LA	01/09/2017 ACT	Fire Water Diesel Pump No. 4 Engine	17.11	Diesel Fuel	Emergency Engine limited to 100 hours/yr for ready tests	Nitrogen Oxides (NOx)	P	Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	U	0	U	0			
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	09/21/2018 ACT	Firewater Pumps	17.11	Diesel Fuel		Nitrogen Oxides (NOx)	P	Good Combustion and Operating Practices.	3.1	G/HP-H		BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0			Comply with 40 CFR 60 Subpart IIII and limiting normal operations to 50 h/yr.
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	09/21/2018 ACT	Large Emergency Engines (>50kW)	17.11	Diesel Fuel	Three emergency black-start engines and two emergency generators	Nitrogen Oxides (NOx)	P	Good Combustion and Operating Practices	5.6	G/KW-H		BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0			Comply with 40 CFR 60 Subpart IIII and limiting normal operations to 100 hr/yr.
LA-0346	GULF COAST METHANOL COMPLEX	IGP METHANOL LLC	LA	01/04/2018 ACT	emergency generators (4 units)	17.11	natural gas		Nitrogen Oxides (NOx)	P	Comply with standards of 40 CFR 60 Subpart JJJJ	2	G/BHP-HR		BACT-PSD	NSPS	U	0	U	0			

LA-0350	BENTELER STEEL TUBE FACILITY	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	LA	03/28/2018 ACT	emergency generators (3 units) EQT0039, EQT0040, EQT0041	17.11			Nitrogen Oxides (NOx)	P	Comply with 40 CFR 60 Subpart IIII	0			BACT-PSD		U	0	U	0			
LA-0364	FG LA COMPLEX	FG LA LLC	LA	01/06/2020 ACT	Emergency Generator Diesel Engines	17.11	Diesel Fuel		Nitrogen Oxides (NOx)	P	Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			Engines are limited to 100 hours of non-emergency use.

LA-0364	FG LA COMPLEX	FG LA LLC	LA	01/06/2020 ACT	Emergency Fire Water Pumps	17.11	Diesel Fuel		Nitrogen Oxides (NOx)	P	Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			Engines are limited to 100 hours of non-emergency use.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	SHINTECH LOUISIANA, LLC	LA	05/04/2021 ACT	VCM Unit Emergency Generator A	17.11	Gaseous fuel	Maximum horsepower rating.	Nitrogen Oxides (NOx)	P	Good combustion practices/gaseous fuel burning.	6.9	G/HP-HR		BACT-PSD		U	0	U	0			
LA-0379	SHINTECH PLAQUEMINES PLANT 1	SHINTECH LOUISIANA, LLC	LA	05/04/2021 ACT	C/A Emergency Generator B	17.11	Gaseous fuel	Maximum horsepower rating.	Nitrogen Oxides (NOx)	P	Good combustion practices/gaseous fuel burning.	6.9	G/HP-HR		BACT-PSD		U	0	U	0			
LA-0382	BIG LAKE FUELS METHANOL PLANT	BIG LAKE FUELS LLC	LA	04/25/2019 ACT	Emergency Engines (EQT0014 - EQT0017)	17.11	Diesel		Nitrogen Oxides (NOx)	P	Comply with standards of 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	U	0	U	0			
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	LAKE CHARLES LNG EXPORT COMPANY, LLC	LA	09/03/2020 ACT	Emergency Engines (EQT0011 - EQT0016)	17.11	Diesel		Nitrogen Oxides (NOx)	P	Comply with 40 CFR 60 Subpart IIII	0			BACT-PSD		U	0	U	0			

MA-0039	SALEM HARBOR STATION REDEVELOPMENT	FOOTPRINT POWER SALEM HARBOR DEVELOPMENT LP	MA	01/30/2014 ACT	Emergency Engine/Generator	17.11	ULSD	â‰¤ 300 hours of operation per 12-month rolling period S in ULSD: â‰¤0.0015% by weight	Nitrogen Oxides (NOx)	N		4.8	GM/BHP-H	1 HR BLOCK AVG	LAER	NSPS , NESHAP , SIP , OPERATING PERMIT	U	0	U	11.6	LB/H	1 HR BLOCK AVG	emission limits are for NOx and VOC combined total. the project is subject LAER for NOx as ozone precursor, and BACT-PSD for NOx as NO2 precursor.
MA-0043	MIT CENTRAL UTILITY PLANT	MASSACHUSETTS INSTITUTE OF TECHNOLOGY	MA	06/21/2017 ACT	Cold Start Engine	17.11	ULSD	CAT DM8263 or equivalent. â‰¤ 8 hours of operation per day, â‰¤ 300 hours of operation per consecutive 12-month period, S in ULSD: â‰¤0.0015% by weight.	Nitrogen Oxides (NOx)	N		35.09	LB/HR	1 HR BLOCK AVG	OTHER CASE-BY-CASE	NESHAP , SIP , OPERATING PERMIT , NSPS	U	0	U	5.3	TONS/C12MP	CONSECUTIVE TWELVE MONTH PERIOD	
MD-0042	WILDCAT POINT GENERATION FACILITY	OLD DOMINION ELECTRIC CORPORATION (ODEC)	MD	04/08/2014 ACT	EMERGENCY GENERATOR 1	17.11	ULTRA LOW SULFU DIESEL	40 CFR 60 SUBPART IIII, ULTRA LOW-SULFUR DIESEL FUEL, GOOD COMBUSTION PRACTICES	Nitrogen Oxides (NOx)	P	LIMITED OPERATING HOURS, USE OF ULTRA-LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	4.8	G/HP-H		LAER	NSPS		0		6.4	G/KW-H		COMBINED NOX AND NMHC
MD-0043	PERRYMAN GENERATING STATION	CONSTELLATION POWER SOURCE GENERATION, INC.	MD	07/01/2014 ACT	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DIESEL	40 CFR 60 SUBPART IIII, GOOD COMBUSTION PRACTICES	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES, LIMITED HOURS OF OPERATION, AND EXCLUSIVE USE OF ULSD	4.8	G/HP-H		LAER	NSPS		0		6.4	G/KW-H		NSPS 40 CFR 60 SUBPART IIII

MD-0044	COVE POINT LNG TERMINAL	DOMINION COVE POINT LNG, LP	MD	06/09/2014 ACT	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DIESEL	40 CFR 60, SUBPART IIII, ULTRA LOW-SULFUR DIESEL FUEL, GOOD COMBUSTION PRACTICES	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES AND DESIGNED TO ACHIEVE EMISSION LIMIT	4.8	G/HP-H	COMBINED NOX + NMHC	LAER	NSPS		0		6.4	G/KW-H	COMBINED NOX + NMHC	NSPS 40 CFR 60 SUBPART IIII
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	MI	11/01/2013 ACT	FG-EMGEN7-8; Two (2) 1,000kW diesel-fueled emergency reciprocating internal combustion engines	17.11	Diesel	1,000 kW (1,502 hp) each; hours restriction = 500 hours each per year.	Nitrogen Oxides (NOx)	P	Good combustion practices	4.8	G/B-HP-H	TEST PROTOCOL; EACH UNIT	BACT-PSD	SIP	N	0	N	0			The NOx limit of 4.8 g/bhp-hr applies to each unit.

MI-0418	WARREN TECHNICAL CENTER	GENERAL MOTORS TECHNICAL CENTER - WARREN	MI	01/14/2015 ACT	FG-BACKUPGENS (Nine (9) DRUPS Emergency Engines)	17.11	Diesel	DRUPS emergency engines identified as the following: EUDRUPS1, EUDRUPS2, EUDRUPS3, EUDRUPS4, EUDRUPS5, EUDRUPS6, EUDRUPS7, EUDRUPS8, EUDRUPS9 permitted within the flexible group that is identified as FG-BACKUPGENS. Each engine is 3490KW each. DRUPS stands for Diesel Rotary Uninterruptable Power supply system. The system provides for zero down-time in electrical energy supply at the onset of a power outage. The system stores energy in a fly-wheel that powers the generator until the diesel engine starts up. Two DRUP engines connect to one	Nitrogen Oxides (NOx)	P	No add-on controls, but injection timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	8	G/KW-H	TEST PROTOCOL (LIMIT IS PER ENGINE)	BACT-PSD	NSPS , NESHAP , SIP , OPERATING PERMIT	N	0	U	0			The emission limit is for each DRUP engine. No add-on controls were technically feasible for these emergency engines, so a cost analysis was not necessary.
MI-0418	WARREN TECHNICAL CENTER	GENERAL MOTORS TECHNICAL CENTER - WARREN	MI	01/14/2015 ACT	Four (4) emergency engines in FG-BACKUPGENS	17.11	Diesel	There are four (4) emergency engines identified as EUGENERATOR1, EUGENERATOR2, EUGENERATOR3, and EUGENERATOR4 in the flexible group identified in the permit as FG-BACKUPGENS. Each engine is 2710 KW. Two engines connect to one standard generator set.	Nitrogen Oxides (NOx)	P	No add-on controls, but injection timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	7.13	G/KW-H	TEST PROTOCOL (LIMIT IS PER ENGINE)	BACT-PSD	NSPS , NESHAP , SIP , OPERATING PERMIT	N	0	U	0			The emission limit is per engine. No add-on controls were technically feasible for these emergency engines so a cost analysis was not necessary.

MI-0421	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	08/26/2016 ACT	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	17.11	Diesel	One emergency diesel generator engine rated at 1600 kW (EUEMRGRICE in FGRICE).	Nitrogen Oxides (NOx)	P	Certified engines, limited operating hours.	22.6	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	SIP	N	0	N	0			Based on the limited hours of operation, the company concluded that add-on control would not be cost effective.
MI-0421	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	08/26/2016 ACT	Dieself fire pump engine (EUFIREPUMP in FGRICE)	17.11	Diesel	One diesel fire pump engine rated at 400 KW (identified as EUFIREPUMP in FGRICE).	Nitrogen Oxides (NOx)	P	Certified engines, limited operating hours.	3.53	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	SIP	N	0	N	0			Based on the limited hours of operation, the company concluded that add on control would not be cost effective.
MI-0423	INDECK NILES, LLC	INDECK NILES, LLC	MI	01/04/2017 ACT	EUEMENGINE (Diesel fuel emergency engine)	17.11	Diesel Fuel	a 2,922 horsepower (HP) (2,179 kilowatts (kW)) diesel fueled emergency engine manufactured in 2011 or later and a displacement of <10 liters/cylinder. Restricted to 4 hours/day, except during emergency conditions and stack testing, and 500 hours/year on a 12-month rolling time period basis.	Nitrogen Oxides (NOx)	P	Good combustion practices and meeting NSPS IIII requirements.	6.4	G/KW-H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in ‘‘NMHC + NOx‘‘ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	05/09/2017 ACT	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	17.11	Diesel	One emergency diesel generator engine rated at 1500 KW (EUEMRGRICE1 in FGRICE).	Nitrogen Oxides (NOx)	P	Certified engines, limited operating hours.	21.2	LB/H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	SIP	N	0	N	0			Based on the limited hours of operation, the company concluded that add-on control would not be cost effective.
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	05/09/2017 ACT	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	17.11	Diesel	One emergency diesel generator engine rated at 1500 KW (EUEMRGRICE2 in FGRICE).	Nitrogen Oxides (NOx)	P	Certified engines, limited operating hours	4.4	LB/H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	SIP	N	0	N	0			Based on the limited hours of operation, the company concluded that add-on control would not be cost effective.

MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	05/09/2017 ACT	EUFIREPUMP in FGRICE (Diesel fire pump engine)	17.11	Diesel	One diesel fire pump engine rated at 400 KW (EUFIREPUMP in FGRICE).	Nitrogen Oxides (NOx)	P	Certified engines. Limited operating hours.	3.53	LB/H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	SIP	N	0	N	0			Based on the limited hours of operation, the company concluded that add-on control would not be cost effective.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	MI	06/29/2018 ACT	EUEMENGINE (North Plant): Emergency Engine	17.11	Diesel	A 1,341 HP (1,000 kilowatts (KW)) diesel-fired emergency engine with a model year of 2011 or later, and a displacement of <10 liters/cylinder. The engine is designed to be compliant with Tier IV emission standards. Equipped with a diesel particulate filter.	Nitrogen Oxides (NOx)	P	Good combustion practices and meeting NSPS Subpart IIII requirements.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in ‘‘NMHC+NOx‘‘ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	MI	06/29/2018 ACT	EUEMENGINE (South Plant): Emergency Engine	17.11	Diesel	A 1,341 HP (1,000 kilowatts (kW)) diesel-fired emergency engine with a model year of 2011 or later, and a displacement of <10 liters/cylinder. The engine is designed to be compliant with Tier IV emission standards. Equipped with a diesel particulate filter.	Nitrogen Oxides (NOx)	P	Good combustion practices and meeting NSPS IIII requirements.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in ‘‘NMHC+NOx‘‘ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.

MI-0434	FLAT ROCK ASSEMBLY PLANT	FORD MOTOR COMPANY	MI	03/22/2018 ACT	EUENGINE 01 through EUENGINE 08	17.11	Diesel	Eight (8) diesel-fueled emergency engine/generators rated at 2,500 kilowatt (kW) / 3,633 brake horsepower (BHP), two (2) emergency fire pump engines rated at 250 BHP and an emergency engine rated at 500 kW. No add-on control.	Nitrogen Oxides (NOx)	P	Good combustion practices.	6.4	G/KW-H	HOURLY; EACH ENGINE; NMHC +NOX	BACT-PSD	NSPS , SIP	N	0	N	42.6	LB/H	HOURLY; EACH ENGINE ; NOX	The first emission limit above is actually in ‘‘NMHC+NOx‘‘ (nonmethane hydrocarbon plus NOx) and is 6.4 G/KW-H for each engine. The limit is based on NSPS IIII. The second emission limit above is actually in NOx and is 42.6 LB/H for each engine.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	DTE ELECTRIC COMPANY	MI	07/16/2018 ACT	EUEMENGINE: Emergency engine	17.11	Diesel	A nominal 2 MW diesel-fueled emergency engine with a model year of 2011 or later, and a displacement of <10 liters/cylinder. The engine is an EPA Tier 2 certified engine subject to NSPS IIII.	Nitrogen Oxides (NOx)	P	State of the art combustion design.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in ‘‘NMHC+NOx‘‘ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	12/21/2018 ACT	EUEMGD1--A 1500 HP diesel fueled emergency engine	17.11	Diesel	A 1500 HP diesel-fueled emergency engine manufactured after 2006 serving a 1,000 kW engine generator with associated fuel oil tank. The engine generator is used to charge the batteries in the uninterruptible power supply battery system.	Nitrogen Oxides (NOx)	P	Good combustion practices and will be NSPS compliant.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	U	0			Emission limit is for NMHC+NOx. Did not consider the additional control to be technically feasible since many controls don't function properly for small emitters and intermittent sources.

MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	12/21/2018 ACT	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	17.11	Diesel	A 6000 HP diesel-fueled emergency engine manufactured after 2006 serving a 4000 kW generator with associated fuel oil tank. The engine generator is used to facilitate operations during idling of the plan for routine maintenance checks and readiness testing.	Nitrogen Oxides (NOx)	P	Good combustion practices and will be NSPS compliant.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	U	0			Emission limit is for NMHC+NOx. Did not consider the additional control to be technically feasible since many controls don't function properly for small emitters and intermittent sources.
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	MI	08/21/2019 ACT	FGEMENGINE	17.11	Diesel	Two (2) diesel-fired emergency engines, each 1,474 HP (1,100 kW) with a model year of 2011 or later, and a displacement of <10 liters/cylinder. The engines are designed to be compliant with Tier 2 emission standards.	Nitrogen Oxides (NOx)	N		5.3	G/HP-H	HOURLY; EACH ENGINE	BACT-PSD	NSPS	N	0	U	0			permit also with a limit of 6.4 G/KW-H, is hourly and applies to each engine. This emission limit is for certified engines; if testing becomes required to demonstrate compliance, then the tested values must be compared to the Not to Exceed (NTE) requirements determined through 40 CFR 60.4212(c). SCR is not technically feasible for emergency engines, which will be small, intermittent sources, only operated for maintenance and testing and in case of a true emergency. Other add-on controls are not considered technically or

*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	MI	11/26/2019 ACT	EUEMENGINE (diesel fuel emergency engine)	17.11	diesel fuel	A 2,922 horsepower (HP) (2,179 kilowatts (kW)) natural gas-fueled emergency engine (EUEMENGINE) manufactured in 2011 or later and a displacement of <10 Liters/cylinder. Restricted to 4 hours/day, except during emergency conditions and stack testing, and 500 hours/year on a 12-month rolling time period basis	Nitrogen Oxides (NOx)	P	Good Combustion Practices and meeting NSPS Subpart IIII requirements	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in â€œNMHC+NOxâ€ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.
MI-0448	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	12/18/2020 ACT	Emergency diesel generator engine (EUEMRGRICE1 in FGRICE)	17.11	Diesel	One emergency diesel generator engine rated at 1500 KW (EUEMRGRICE1 in FGRICE).	Nitrogen Oxides (NOx)	P	Certified engines, limited operating hours	21.2	LB/H	HOURLY	BACT-PSD		N	0	N	0			Based on the limited hours of operation, Arauco concluded that add-on control would not be cost effective.
MI-0448	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	12/18/2020 ACT	Emergency diesel generator engine (EUEMRGRICE2 in FGRICE)	17.11	Diesel	One emergency diesel generator engine rated at 500 KW (EUEMRGRICE2 in FGRICE).	Nitrogen Oxides (NOx)	P	Certified Engines, Limited Operating Hours	4.4	LB/H	HOURLY	BACT-PSD		N	0	N	0			Based on the limited hours of operation, Arauco concluded that add-on control would not be cost effective.
MI-0448	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	12/18/2020 ACT	Diesel fire pump engine (EUFIREPUMP in FGRICE)	17.11	Diesel	One diesel fire pump engine rated at 400 KW (EUFIREPUMP in FGRICE).	Nitrogen Oxides (NOx)	P	Certified Engines, Limited Operating Hours	3.53	LB/H	HOURLY	BACT-PSD		N	0	N	0			Based on the limited hours of operation, Arauco concluded that add-on control would not be cost effective.
NJ-0080	HESS NEWARK ENERGY CENTER	HESS NEWARK ENERGY CENTER, LLC	NJ	11/01/2012 ACT	Emergency Generator	17.11	ULSD		Nitrogen Oxides (NOx)	P	use of ultra low sulfur diesel (ULSD) a clean fuel	18.53	LB/H		LAER	NSPS , OPERATING PERMIT	U	0	U	0			

NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	NJ	03/10/2016 ACT	Diesel Fired Emergency Generator	17.11	ULSD		Nitrogen Oxides (NOx)	P	use of ultra low sulfur diesel a clean burning fuel.	42.3	LB/H		LAER	NSPS , OPERATING PERMIT	N	0	N	0			
NY-0103	CRICKET VALLEY ENERGY CENTER	CRICKET VALLEY ENERGY CENTER LLC	NY	02/03/2016 ACT	Black start generator	17.11	ultra low sulfur diesel		Nitrogen Oxides (NOx)	B	Generator equipped with selective catalytic reduction. Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.	2.11	G/BHP-H	1 H	LAER		U	0	U	0			
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	OH	06/18/2013 ACT	Emergency generator	17.11	diesel	Emergency diesel fired generator restricted to 500 hours of operation per rolling 12-months.	Nitrogen Oxides (NOx)	P	Purchased certified to the standards in NSPS Subpart IIII	27.8	LB/H		BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	6.95	T/YR	PER ROLLING 12-MONTHS	Additional limits: 5.61 g NOx/kW-H; and 6.4 g NMHC + NOx/kW-hr, the standard from Subpart IIII. Method 7E if required.
OH-0355	GENERAL ELECTRIC AVIATION, EVENDALE PLANT	GENERAL ELECTRIC	OH	05/07/2013 ACT	Test Cell 1 for Aircraft Engines and Turbines	17.11	JET FUEL	Fuels tested include jet fuel, diesel fuel, biofuels and gaseous fuels. Size of engine turbine varies, none specified. Installed with a continuous fuel flow monitor.	Nitrogen Oxides (NOx)	N		1.7	LB/MMBTU	LAER AND PSD LIMIN	LAER	SIP	U	0	U	92	T/YR	PER ROLLING 12 MONTHS	The emission limit of 1.70 LB NOX/MMBtu is considered LAER, based on design emission levels. Must develop an Emissions Protocol Document on the potential to emit.

OH-0355	GENERAL ELECTRIC AVIATION, EVENDALE PLANT	GENERAL ELECTRIC	OH	05/07/2013 ACT	Test Cell 2 for Aircraft Engines and Turbines	17.11	JET FUEL	Fuels tested include jet fuel, diesel fuel, biofuels and gaseous fuels. Size of engine turbine varies, none specified. Installed with a continuous fuel flow monitor.	Nitrogen Oxides (NOx)	N		4.4	LB/MMBTU		LAER	SIP	U	0	U	80	T/YR	PER ROLLING 12 MONTHS	The emission limit of 4.4 LB NOX/MMBtu is considered LAER, based on design emission levels. Must develop an Emissions Protocol Document on the potential to emit.
OH-0360	CARROLL COUNTY ENERGY	CARROLL COUNTY ENERGY	OH	11/05/2013 ACT	Emergency generator (P003)	17.11	diesel	1,112 kW emergency diesel fired generator.	Nitrogen Oxides (NOx)	P	Purchased certified to the standards in NSPS Subpart IIII	13.74	LB/H		BACT-PSD	NSPS	U	0	U	3.44	T/YR	PER ROLLING 12 MONTH PERIOD	Additional limits: 5.61 g NOx/kW-H; and 6.4 g NMHC + NOx/kW-hr, the standard from Subpart IIII.
OH-0363	NTE OHIO, LLC		OH	11/05/2014 ACT	Emergency generator (P002)	17.11	Diesel fuel	Emergency diesel engine powered standby generator, rated at 1,100 kilowatts.	Nitrogen Oxides (NOx)	P	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII	29.01	LB/H		BACT-PSD	NSPS	U	0	U	7.25	T/YR	PER ROLLING 12 MONTH PERIOD	
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	08/25/2015 ACT	Emergency generator (P003)	17.11	Diesel fuel	1,750 kW (2,346 hp) emergency generator	Nitrogen Oxides (NOx)	P	State-of-the-art combustion design	21.6	LB/H		BACT-PSD	NSPS	U	0	U	5.41	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 5.61 g/kW-hr and Non-methane hydrocarbon (NMHC) + NOx emissions shall not exceed 6.4 g/kW-hr.
OH-0367	SOUTH FIELD ENERGY LLC	SOUTH FIELD ENERGY LLC	OH	09/23/2016 ACT	Emergency generator (P003)	17.11	Diesel fuel	2,000 kW electric, 2,198 kW mechanical (2,947 hp) emergency diesel generator	Nitrogen Oxides (NOx)	P	State-of-the-art combustion design	27.18	LB/H		BACT-PSD	NSPS	U	0	U	6.8	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 5.61 g/kW-hr. NSPS: Non-methane hydrocarbon (NMHC) + NOx emissions shall not exceed 6.4 g/kW-hr.

OH-0368	PALLAS NITROGEN LLC	PALLAS NITROGEN LLC	OH	04/19/2017 ACT	Emergency Generator (P009)	17.11	Diesel fuel	5,000 HP â€" 3,729 kW Emergency Generator Diesel Engine	Nitrogen Oxides (NOx)	P	good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII	5.5	LB/H		BACT-PSD	NSPS	U	0	U	0.3	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 0.67 g/kW-hr. NSPS limit is NMHC + NOx emissions shall not exceed 6.4 g/kW-hr (3.0 g/hp-hr).
OH-0370	TRUMBULL ENERGY CENTER	TRUMBULL ENERGY CENTER	OH	09/07/2017 ACT	Emergency generator (P003)	17.11	Diesel fuel	Emergency Generator 1000 kW (electrical), 1,140 kW (mechanical), 1,529 hp	Nitrogen Oxides (NOx)	P	State-of-the-art combustion design	16.07	LB/H		BACT-PSD	NSPS	U	0	U	4.02	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 6.4 g/kW-hr. NSPS limit is Non-methane hydrocarbon (NMHC) + NOx emissions shall not exceed 6.4 g/kW-hr.
OH-0372	OREGON ENERGY CENTER	OREGON ENERGY CENTER	OH	09/27/2017 ACT	Emergency generator (P003)	17.11	Diesel fuel	1,000 kWe (1,140 kW mechanical) emergency diesel-fired generator	Nitrogen Oxides (NOx)	P	State-of-the-art combustion design	16.1	LB/H		BACT-PSD	NSPS	U	0	U	4.02	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 6.4 g/kW-hr (4.8 g/hp-hr). NSPS: Non-methane hydrocarbon (NMHC) + NOX emissions shall not exceed 6.4 g/kW-hr.

OH-0374	GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	10/23/2017 ACT	Emergency Generators (2 identical, P004 and P005)	17.11	Diesel fuel	Two identical Emergency Generators; 1,645 kW (2,206 HP) emergency diesel-fired generator to provide on-site emergency power capabilities independent of the utility grid. Throughputs and limits are for a single generator except as noted.	Nitrogen Oxides (NOx)	P	Certified to the meet the emissions standards in 40 CFR 89.112 and 89.113 pursuant to 40 CFR 60.4205(b) and 60.4202(a)(2) . Good combustion practices per the manufacturer â€™s operating manual.	23.21	LB/H	NMHC +NOX. SEE NOTES.	BACT-PSD	NSPS	U	0	U	1.16	T/YR	NMHC+ NOX. SEE NOTES.	Non-methane hydrocarbon plus nitrogen oxides (NMHC+NOx) emissions shall not exceed 6.40 g/kW-hour (4.77 G/BHP-H), 23.21 pounds per hour and 1.16 tons per rolling, 12-month period.
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	11/07/2017 ACT	Emergency Diesel Generator Engine (P001)	17.11	Diesel fuel	1,645 kW (2,206 HP) emergency diesel-fired generator to provide on-site emergency power capabilities independent of the utility grid.	Nitrogen Oxides (NOx)	P	Good combustion design	24.71	LB/H	NMHC +NOX. SEE NOTES.	BACT-PSD	NSPS	U	0	U	1.24	T/YR	NMHC+ NOX. SEE NOTES.	Non-methane hydrocarbon plus nitrogen oxides (NMHC+NOx) emissions shall not exceed 6.40 g/kW-h (4.8 g/hp-h), 24.71 lb/h and 1.24 t/yr per rolling, 12-month period.

OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	11/07/2017 ACT	Emergency Diesel Fire Pump Engine (P002)	17.11	Diesel fuel	700 hp emergency diesel-fired fire pump to provide on-site firefighting capabilities independent of the utility grid	Nitrogen Oxides (NOx)	P	Good combustion design	4.97	LB/H	NMHC +NOX. SEE NOTES.	BACT-PSD	NSPS	U	0	U	0.25	T/YR	NMHC+ NOX. SEE NOTES.	Nonmethane hydrocarbons plus nitrogen oxides (NMHC+NOx) emissions shall not exceed 4.0 g/kW-hour, 4.97 pounds per hour and 0.25 ton per rolling, 12-month period. NSPS: Non-methane hydrocarbon (NMHC) + NOX emissions shall not exceed 4.0 g/kW-hr (3.0 g/hp-hr).
OH-0376	IRONUNITS LLC - TOLEDO HBI	IRONUNITS LLC - TOLEDO HBI	OH	02/09/2018 ACT	Emergency diesel-fired generator (P007)	17.11	Diesel fuel	2,000 kW (2,682 hp) emergency diesel-fired generator	Nitrogen Oxides (NOx)	P	Comply with NSPS 40 CFR 60 Subpart IIII	28.2	LB/H		BACT-PSD	NSPS	U	0	U	7.05	T/YR	PER ROLLING 12 MONTH PERIOD	NOx Standard limit is 6.4 g/kW-hr (4.8 g/hp-hr). NSPS: Non-methane hydrocarbon (NMHC) + NOX emissions shall not exceed 6.4 g/kW-hr (4.8 g/hp-hr).
OH-0377	HARRISON POWER	HARRISON POWER	OH	04/19/2018 ACT	Emergency Diesel Generator (P003)	17.11	Diesel fuel	1,387 KW (1,860 HP) emergency diesel-fired generator	Nitrogen Oxides (NOx)	P	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	19.68	LB/H	NMHC +NOX. SEE NOTES.	BACT-PSD	NSPS	U	0	U	0.98	T/YR	NMHC+ NOX. SEE NOTES.	All emissions limits are for Non-methane hydrocarbon (NMHC) + NOX emissions. 0.98 t/yr per rolling, 12-month period. NSPS: Non-methane hydrocarbon (NMHC) + NOX emissions shall not exceed 6.4 g/kW-hr (4.8 g/hp-hr).

OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018 ACT	Emergency Diesel-fired Generator Engine (P007)	17.11	Diesel fuel	2,500 kW (3,353 HP) emergency diesel-fired generator engine	Nitrogen Oxides (NOx)	P	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer â€™s operating manual	37.41	LB/H	SEE NOTES.	BACT-PSD	NSPS	U	0	U	1.87	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	Emission limits are for non-methane hydrocarbon plus nitrogen oxides (NMHC + NOx). Non-methane hydrocarbon plus nitrogen oxides (NMHC + NOx) emissions shall not exceed 6.4 g/kW-hour (4.8 g/HP-hour), 37.41 pounds per hour and 1.87 tons per rolling, 12-month period.
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018 ACT	1,000 kW Emergency Generators (P008 - P010)	17.11	Diesel fuel	Three identical ECU Generators 1 to 3; 1,000 kW (1,341 HP) emergency diesel-fired generator engine. Limits are for single generator except as noted.	Nitrogen Oxides (NOx)	P	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer â€™s operating manual	14.96	LB/H	SEE NOTES.	BACT-PSD	NSPS	U	0	U	0.75	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	Emission limits are for non-methane hydrocarbon plus nitrogen oxides (NMHC + NOx). Non-methane hydrocarbon plus nitrogen oxides (NMHC + NOx) emissions shall not exceed 6.4 g/kW-hour (4.8 g/HP-hour), 14.96 pounds per hour and 0.75 ton per rolling, 12-month period.
OH-0379	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	02/06/2019 ACT	Emergency Generators (P005 and P006)	17.11	Diesel fuel	Two identical Emergency generators, 3131 HP diesel engines. Throughputs and limits are for one generator, except as noted.	Nitrogen Oxides (NOx)	P	Tier IV engine Tier IV NSPS standards certified by engine manufacturer.	3.45	LB/H		BACT-PSD	NSPS	U	0	U	0.17	T/YR		NSPS: 4.8 grams NOx + NMHC/bhp-hr

OH-0383	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	07/17/2020 ACT	Diesel-fired emergency fire pumps (2) (P009 and P010)	17.11	Diesel fuel	Two identical fire pump 3131 HP diesel engines. Throughputs and limits are for one engine, except as noted.	Nitrogen Oxides (NOx)	P	Tier IV NSPS standards certified by engine manufacturer.	0			BACT-PSD	NSPS	U	0	U	0			
OK-0154	MOORELAND GENERATING STA	WESTERN FARMERS ELECTRIC COOPERATIVE	OK	07/02/2013 ACT	DIESEL-FIRED EMERGENCY GENERATOR ENGINE	17.11	DIESEL	<100 HR/YR OPERATION.	Nitrogen Oxides (NOx)	P	COMBUSTION CONTROL	0.011	LB/HP-HR		BACT-PSD	NSPS	U	0	U	0			
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	MOXIE ENERGY LLC	PA	10/10/2012 ACT	Emergency Generator	17.11	Diesel	The emergency generator will be restricted to operate not more than 100 hr/yr.	Nitrogen Oxides (NOx)	N		4.93	G/B-HP-H		OTHER CASE-BY-CASE	OTHER	U	0	U	0			
PA-0291	HICKORY RUN ENERGY STATION	HICKORY RUN ENERGY LLC	PA	04/23/2013 ACT	EMERGENCY GENERATOR	17.11	Ultra Low sulfur Distillate	EMERGENCY GENERATOR (1,135 BHP - 750 KW)	Nitrogen Oxides (NOx)	N		9.89	LB/H		OTHER CASE-BY-CASE	OTHER	U	0	U	0.49	T/YR	12-MONTH ROLLING TOTAL	
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	LACKAWANNA ENERGY CENTER, LLC	PA	12/23/2015 ACT	2000 kW Emergency Generator	17.11	Ultra-low sulfur Diesel	To allow maintenance of vital plant loads during power outages or maintenance of the switchyard.	Nitrogen Oxides (NOx)	N		5.45	GM/HP-HR		LAER		U	0	U	0.81	TONS	12-MONTH ROLLING BASIS	
PA-0310	CPV FAIRVIEW ENERGY CENTER	CPV FAIRVIEW, LLC	PA	09/02/2016 ACT	Emergency Generator Engines	17.11	ULSD	(2) 1500 kW emergency diesel genset. Emission limitations are for each genset and fuel is restricted to ULSD (15 ppm) and each is restricted to 100 hrs on a 12-month rolling basis.	Nitrogen Oxides (NOx)	N		4.8	G/BHP-HR		LAER	NSPS	U	0	U	0			

PA-0311	MOXIE FREEDOM GENERATION PLANT	MOXIE FREEDOM LLC	PA	09/01/2015 ACT	Emergency Generator	17.11		Sulfur content of the diesel fuel combusted by the emergency diesel generator shall not exceed 15 ppm. Shall maintain and operate the source in accordance with good engineering practice.	Nitrogen Oxides (NOx)	N		4.93	G/HP-HR		LAER	NSPS	U	0	U	0.4	TPY	12-MONTH ROLLING BASIS	
PA-0311	MOXIE FREEDOM GENERATION PLANT	MOXIE FREEDOM LLC	PA	09/01/2015 ACT	Fire Pump Engine	17.11	diesel	Sulfur content of the diesel fuel combusted by the fire engine pump shall not exceed 15 ppm. Shall maintain and operate the source in accordance with good engineering practice.	Nitrogen Oxides (NOx)	N		3	G/HP-HR		LAER	NSPS	U	0	U	0.08	TPY	12-MONTH ROLLING BASIS	
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	ENERGY ANSWERS ARECIBO, LLC	PR	04/10/2014 ACT	Emergency Diesel Generator	17.11	ULSD Fuel oil # 2	Emergency Generator is rated at 670 BHP and is limited to 500 hr per year (emergency and testing and maintenance, combined)	Nitrogen Oxides (NOx)	N		2.85	G/B-HP-H		BACT-PSD		U	0	U	4.2	LB/H		
TX-0671	PROJECT JUMBO	M&G RESINS USA, LLC	TX	12/01/2014 ACT	Engines	17.11	ultra low sulfur diesel fuel	Two mergency diesel fired generators proposed. Each engine will be 4000 kW. Ultra low sulfur fuel is burned in the engines to meet the sulfur requirement of 15 ppm in 40CFR80.510(b). Each emergency engine is being permitted for maintenance and testing for maximum 100 hrs/yr. They are not being permitted for the actual emergency emissions	Nitrogen Oxides (NOx)	P	Each emergency generator's emission factor is based on EPA's Tier 2 standards at 40CFR89.112 for NOx	5.43	G/KW-H		BACT-PSD	NSPS	U	0	U	2.39	T/YR		

TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	BASF	TX	04/01/2015 ACT	Emergency Diesel Generator	17.11	Diesel	generator (EPN 17-1-4) at the site is diesel fired and rated at 1500 horsepower (hp). Lowest Achievable Emission Rates (LAER) for nitrogen oxides (NOx) is the use of a 40 Code Federal Rules (CFR) Part 89 Tier 2 engine and limited hours of operation. Emissions from the engine shall not exceed 0.0218 grams per horsepower-hour (g/hp-hr) of nitrogen oxides (NOx). The engine is limited to 52 hours per year of non-emergency operation. Emissions from the engine shall not exceed 0.01256 g/hp hr of carbon monoxide (CO). The fuel for the engine is limited to 15 parts per million sulfur by weight (ultra-low sulfur diesel).	Nitrogen Oxides (NOx)	P	Minimized hours of operations Tier II engine	0.0218	G/HP HR		LAER	NSPS , MACT	N	0	U	0.35	TPY		
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	MOTIVA ENTERPRISE LLC	TX	02/06/2020 ACT	Emergency generator	17.11	DIESEL	Ultra-low sulfur diesel containing no more than 15 ppmw total sulfur	Nitrogen Oxides (NOx)	P	Tier 4 exhaust emission standards specified in 40 CFR Â§ 1039.101, limited to 100 hours per year of non-emergency operation	0			BACT-PSD	NSPS , MACT	N	0	U	0			NSPS IIII, MACT ZZZZ

TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	MOTIVA ENTERPRISE LLC	TX	02/06/2020 ACT	Emergency firewater pumps	17.11		Ultra-low sulfur diesel containing no more than 15 ppmw total sulfur	Nitrogen Oxides (NOx)	P	Tier 3 exhaust emission standards specified in 40 CFR Â§ 89.112, limited to 100 hours per year of non-emergency operation	0			BACT-PSD	NSPS , MACT	N	0	U	0			
TX-0879	MOTIVA PORT ARTHUR TERMINAL	MOTIVA ENTERPRISES LLC	TX	02/19/2020 ACT	Emergency Firewater Engine	17.11	Ultra-low sulfur diesel	Ultra-low sulfur diesel containing no more than 15 ppmw total sulfur	Nitrogen Oxides (NOx)	P	Meeting the requirements of 40 CFR Part 60, Subpart IIII. Firing ultra-low sulfur diesel fuel (no more than 15 ppm sulfur by weight). Limited to 100 hrs/yr of non-emergency operation. Have a non-resettable runtime meter.	0			BACT-PSD	NSPS , MACT	N	0	U	0			NSPS IIII MACT ZZZZ
TX-0888	ORANGE POLYETHYLENE PLANT	CHEVRON PHILLIPS CHEMICAL COMPANY LP	TX	04/23/2020 ACT	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	17.11	Ultra-low Sulfur Diesel		Nitrogen Oxides (NOx)	P	well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.	0			BACT-PSD	NSPS , MACT	N	0	U	0			

TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX		TX	09/09/2020 ACT	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DIESEL		Nitrogen Oxides (NOx)	P	100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR Â§ 1039.101	0			BACT-PSD		N	0	U	0			
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	DIAMOND GREEN DIESEL	TX	09/16/2020 ACT	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DIESEL		Nitrogen Oxides (NOx)	P	limited to 100 hours per year of non-emergency operation	0			BACT-PSD		N	0	U	0			
TX-0933	NACERO PENWELL FACILITY	NACERO TX 1 LLC	TX	11/17/2021 ACT	Emergency Generators	17.11	Ultra-low sulfur diesel (no more than 15		Nitrogen Oxides (NOx)	P	limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR Â§ 1039.101) exhaust emission standards	0			BACT-PSD		N	0	U	0			
VA-0325	GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	06/17/2016 ACT	DIESEL-FIRED EMERGENCY GENERATOR 3000 kW (1)	17.11	DIESEL FUEL		Nitrogen Oxides (NOx)	P	Good Combustion Practices/Maintenance	6.4	G/KW	PER HR	N/A		U	0	U	10.6	T/YR	12 MO ROLLING TOTAL	

VA-0328	C4GT, LLC	NOVI ENERGY	VA	04/26/2018 ACT	Emergency Diesel GEN	17.11	Ultra Low Sulfur Diesel		Nitrogen Oxides (NOx)	P	good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	4.8	G/HP H		BACT-PSD	NSPS , SIP	N	0	N	9.6	T/YR	12 MO ROLLIN G AV	NOX + NMHC
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	VA	06/24/2019 ACT	Emergency Diesel Generator - 300 kW	17.11	Ultra Low Sulfur Diesel		Nitrogen Oxides (NOx)	P	good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	4.8	G/HP-H		BACT-PSD	NSPS , SIP	N	0	N	11.7	T/YR	12 MO ROLLIN G AVG	Emission Limit 3: 4.8 G/HP - HR

WI-0284	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT		WI	04/24/2018 ACT	Diesel-Fired Emergency Generators	17.11	Diesel Fuel	Ten, 2,180kW Diesel-Fired Emergency Generators.	Nitrogen Oxides (NOx)	P	The Use of Ultra-Low Sulfur Fuel and Good Combustion Practices	5.36	G/KWH		BACT-PSD	NSPS , NESHAP	N	0	U	0			BACT is Total hours of operation for each generator is 200 hours over a 12 month period. Ultra-low sulfur fuel contains less than 15 ppm sulfur. Good combustion practices are defined as maintaining the stationary compression ignition internal combustion engine according to each manufacturerâ€™s emission-related instructions.
WI-0286	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	SIO INTERNATIONAL	WI	04/24/2018 ACT	P42 -Diesel Fired Emergency Generator	17.11	Diesel Fuel	Maximum Continuous Rating: 1,750 kW or 2,346 bhp	Nitrogen Oxides (NOx)	P	Good Combustion Practices, The Use of an Engine Turbocharger and Aftercooler.	5.36	G/KWH		BACT-PSD	NSPS , NESHAP	N	0	U	0			BACT is Good combustion practices are defined as maintaining the stationary compression ignition internal combustion engine according to the manufacturerâ€™s emission-related written instructions. The total hours of operation of the emergency generator may not exceed 200 hours during each consecutive 12-month period.

*WI-0300	NEMADJI TRAIL ENERGY CENTER	NEMADJI TRAIL ENERGY CENTER	WI	09/01/2020 ACT	Emergency Diesel Generator (P07)	17.11	Diesel		Nitrogen Oxides (NOx)	P	Operation limited to 500 hours/year and operate and maintain according to the manufacturer â€™s recommendations.	4.8	G/HP-H		BACT-PSD		U	0	U	0			
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	MOUNDSVILLE POWER, LLC	WV	11/21/2014 ACT	Emergency Generator	17.11	Diesel	Nominal 1,500 kW. Limited to 100 hours/year.	Nitrogen Oxides (NOx)	N		0			BACT-PSD	NSPS	U	0	U	0			
WV-0027	INWOOD	KNAUF INSULATION INC.	WV	09/15/2017 ACT	Emergency Generator - ESDG14	17.11	ULSD	Used to supply power to the facility in the event of power loss	Nitrogen Oxides (NOx)	P	Engine Design	4.77	G/HP-HR		BACT-PSD	NSPS , MACT	U	0	U	0			Engine is limited to 100 hours of non-emergency use per year.
*WV-0033	MAIDSVILLE	MOUNTAIN STATE CLEAN ENERGY, LLC	WV	01/05/2022 ACT	Emergency Generator	17.11	ULSD	4SLB Diesel-Fired Emergency Engine - Subpart IIII	Nitrogen Oxides (NOx)	P	Combustion Control (retarded timing and/or lean burn)	24.6	LB/HR		BACT-PSD	NSPS	N	0	U	6.4	G/BKW	NMHC+ NOX	Certified Engine
*WV-0033	MAIDSVILLE	MOUNTAIN STATE CLEAN ENERGY, LLC	WV	01/05/2022 ACT	Fire Water Pump	17.11	ULSD	4SLB Diesel-Fired Emergency Engine - Subpart IIII.	Nitrogen Oxides (NOx)	P	Combustion control (retarded timing and/or lean burn)	1.59	LB/HR		BACT-PSD	NSPS	U	0	U	4	G/BKW		Certified Engine

Appendix B Air Force Directive Prohibiting the Use of Natural Gas

DEPARTMENT OF THE AIR FORCE
AIR FORCE CIVIL ENGINEER CENTER
TYNDALL AIR FORCE BASE FLORIDA

15 May 2014

FROM: AFCEC/DD
139 Barnes Drive Suite 1
Tyndall AFB, FL 32403-5319

SUBJECT: **Engineering Technical Letter (ETL) 13-4 (Change 1): Standby Generator Design, Maintenance, and Testing Criteria**

1. Purpose. This ETL provides criteria for design, maintenance, and testing of Air Force emergency and standby generator systems. It supersedes ETL 11-21, *Emergency and Standby Generator Design, Maintenance, and Testing Criteria* (Change 2), dated 16 March 2012. Requirements in this ETL modify or replace guidance within Air Force instruction (AFI) 32-1062, *Electrical Power Plants and Generators*, and AFI 32-1063, *Electric Power Systems*, as detailed in paragraphs 1.1, 1.2, and 6. **Use the *Inspection Checklist for the Generator Operating Log* (see paragraph 3.8) for all requirements of this ETL in lieu of AF IMT 487 (revision pending) until further notice.**

1.1. Criteria replaced by this ETL include:

1.1.1. AFI 32-1062:
- paragraph 9
- paragraph 10 and subparagraphs
- A2.3

1.1.2. AFI 32-1063:
- paragraph 1.8.8
- paragraph 4
- paragraphs 5.1 and 5.2
- paragraphs 7.1, 7.2, and 7.3, and their subparagraphs

1.2. Use this ETL with AFI 32-1062; AFI 32-1063; Title 40 Code of Federal Regulations (CFR) Part 60 Subparts IIII and JJJJ; 40 CFR Part 63 Subpart ZZZZ; 40 CFR Part 89.

Note: Use of the name or mark of a specific manufacturer, commercial product, commodity, or service in this ETL does not imply endorsement by the Air Force.

Summary of Revisions: Expanded guidance for semiannual RPIE generator testing (paragraph 15.3.1) to recommend testing with loss of power to the entire facility when verifying connectivity and proper operation of all mission loads.

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21.2. Oil Change Intervals. An oil change may be deferred for a maximum of 12 months, provided:

21.2.1. Total operating hours are less than 150 within the last 12 months. Oil change interval may not exceed 24 months or manufacturer's recommended engine hours.

21.2.2. The oil analysis meets requirements for fuel dilution, viscosity, and total base (acid) content. Sample in accordance with manufacturers' recommendations and field test using oil analysis kit NSN 6630-01-096-4792, *Test Kit, Oil Condition*, or an independent oil analysis company test kit (e.g., Cummins Filtration #CC2543; Caterpillar S•O•S^{SM}; Wix Filters). Record results on *Inspection Checklist for the Generator Operating Log* and AF IMT 719. If an approved field test kit is not available or the above tests are not performed, the oil must be changed.

22. Fuels.

22.1. Fuel oils used for standby generators must meet Federal Specification A-A-52557, *Fuel Oil, Diesel; For Posts, Camps, and Stations*. Follow the specific temperature and applicable service conditions and ensure sulfur content does not exceed environmental restrictions. Do not mix different grades of fuel. Consult T.O. 42B-1-1, *Quality Control of Fuels and Lubricants*, and MIL-STD-3004, *Quality Assurance/Surveillance for Fuels, Lubricants and Related Products*, for additional information.

22.2. Jet fuel potentially may be used with required additives when diesel is not available. Consult the AFCEC/CZTQ for local and Environmental Protection Agency (EPA) emission restrictions. (Consult the manufacturer for kW de-rating when using JP-8 or Jet A(m).)

22.3. Use of natural gas (NG), liquid petroleum gas (LPG), or bio-diesel fuels is not permitted for mission-essential standby generation. NG, LPG, or alternate fuels may be authorized for prime power generation or co-generation. BCEs must either program existing mission-essential generators that use NG, LPG, or bio-diesel for replacement within five years or request a waiver from the MAJCOM/A7 for continued operation. BCEs will ensure refueling plans address backup fuel support for existing mission-essential, non-diesel generators in the event of fuel supply disruption.

22.4. Personnel must be trained to manage fuel storage tanks in accordance with AFI 23-204, *Organizational Fuel Tanks*. Ensure storage tanks are marked according to fuel type and warning signs are appropriately located. If an external fuel tank is installed, post a one-line diagram of the fuel system indicating tank size and valve locations.

24.2. AFCEC/COSM must be notified through the MAJCOM when a generator authorization is no longer required.

24.3. The BCE will prepare a plan for all generators that do not have an AFCEC authorization and are available for relocation or disposition. The plan will be included as a part of the revalidation process.

25. Point of Contact. Generator requests and recommendations for improvements to this ETL are encouraged and should be furnished to the Electrical subject matter expert, AFCEC/COSM, 139 Barnes Drive, Suite 1, Tyndall AFB, FL 32403-5319, DSN 523-6813, commercial (850) 283-6813, email: AFCEC.RBC@us.af.mil

ANTHONY A. HIGDON, Colonel, USAF
Deputy Director

5 Atchs
1. New and Replacement Authorization Template
2. Generator Design Evidence Template
3. Existing Generator Authorization and Design Sizing Template
4. AF/A7C Memorandum for Authorization and Size Validation of Emergency and Standby Generators
5. Distribution List

Appendix C Cost Analysis

Cost Analysis for EU G041 - Replacement with 1,000kW Tier 2 Generator

Existing Source Information	
Uncontrolled Nox Emission Factor (g/kW-hr):	16.09
Maximum Run Time (hr/yr):	500
Capacity (kW):	818
PTE (tons/yr):	8.07
5-Year Actual Average NOx (tons/yr):	0.93
Equipment Life, Interest, Capital Recovery Factor	
Useful Life Equipment (years):	30
Annual Interest Rate (%):	0.06
Calculated Capital Recovery Factor:	0.0726
Emission Reduction	
Uncontrolled Emission Factor (g/kW-hr)):	16.09
Tier 2 Emission Standard (incl NMVOC) (g/kW-hr):	6.4
5-Year Actual Average NOx (tons/yr):	0.93
Control Efficiency (%):	60%
Annual Emissions Reduced (tpy):	0.56
Direct Costs - Equipment, Construction	
Capital (Direct)	
NPV, Tier 2 1,000kW engines:	$299,500
Material:	incl.
Structural Support:	unkn.
Construction (Direct)	
Instrumentation (10% Capital):	$29,950
Engineering (10% Capital):	$29,950
Construction and Field Cost (10% Capital):	$29,950
Incidental & Miscellaneous (assume 10% Engr/Comm/Labor/Equip):	$29,950
Delivery (5% Capital):	$14,975
Other (Direct)	
Taxes (8% Capital):	$23,960
TOTAL DIRECT COST:	$458,235
Indirect Costs - Operating, Maintenance	
Maintenance & Monitoring	
Maintenance & Monitoring ($/yr):	unkn.
Catalyst Replacement	
Catalyst Replacement:	N/A
Install/Construction (10% of Original):	N/A
Other (Indirect)	
Overhead (60% of all labor plus maintenance materials-EPA Cost Manual):	unkn.

Administration (2% of total capital investment- EPA Cost Manual):	*$5,990*
Property Taxes (1% of total capital investment- EPA Cost Manual):	*$2,995*
Insurance (1% of total capital investment- EPA Cost Manual):	*$2,995*
TOTAL INDIRECT COST:	*$11,980*
Total Annualized Direct and Indirect Costs	
TOTAL ANNUALIZED DIRECT COST:	*$33,290*
TOTAL ANNUALIZED INDIRECT COST:	*$870*
TOTAL ANNUALIZED COST:	*$34,161*
Cost Effectiveness	
NOx control cost(Total Annualized Costs/Annual Nox Emissions Reduced):	*$60,987*

Notes:

**NPV rough estimate from Caterpillar (rough estimate only, not a quote) September 1, 2022*

**Useful life of engines assumed to be 30 years.*

** Control % estimated based on emission standards for replacement engine.*

** Items indicated as unknown were set to zero in order to be conservative.*

** Annual interest rate max set by DAQ.*

** Annualized costs estimated by multiplying line items times the calculated capital recovery factor.*

** Capital Recovery Factor calculation is illustrated below.*

Capital Recovery Calculation : $\frac{\text{interest rate} \times (1+\text{interest rate})^{\text{Equipment Life}}}{[(1+\text{interest rate})^{\text{Equipment Life}}]-1}$

Capital Recovery Factor, 30 yr = $\frac{0.06x(1+0.06)^{30}}{[(1+0.06)^{30}]-1}$

$= \frac{0.34460947}{4.743491173}$

$= 0.072648911$

Cost Analysis for EU G041 - Replacement with Tier 3 Generator

Existing Source Information	
Uncontrolled Nox Emission Factor (g/kW-hr):	*16.09*
Maximum Run Time (hr/yr):	*500*
Capacity (kW):	*818*
PTE (tons/yr):	*8.07*
5-Year Actual Average NOx (tons/yr):	*0.93*
Equipment Life, Interest, Capital Recovery Factor	
Useful Life Equipment (years):	*30*
Annual Interest Rate (%):	*0.06*
Calculated Capital Recovery Factor:	*0.0726*
Emission Reduction	
Uncontrolled Emission Factor (g/kW-hr)):	*16.09*
Tier 3 Emission Standard (for lower capacity units) (g/kW-hr):	*4.00*
5-Year Actual Average NOx (tons/yr):	*0.93*
Control Efficiency (%):	*75%*
Annual Emissions Reduced (tpy):	*0.70*
Direct Costs - Equipment, Construction	
Capital (Direct)	
NPV, Tier 3 engine (extrapolated cost, estimated)	*$1,769,067*
Material:	*incl.*
Structural Support:	*unkn.*
Construction (Direct)	
Instrumentation (10% Capital):	*$176,907*
Engineering (10% Capital):	*$176,907*
Construction and Field Cost (10% Capital):	*$176,907*
Incidental & Miscellaneous (assume 10% Engr/Comm/Labor/Equip):	*$176,907*
Delivery (5% Capital):	*$88,453*
Other (Direct)	
Taxes (8% Capital):	*$141,525*
TOTAL DIRECT COST:	*$2,706,673*
Indirect Costs - Operating, Maintenance	
Maintenance & Monitoring	
Maintenance & Monitoring ($/yr):	*unkn.*
Catalyst Replacement	
Catalyst Replacement:	*N/A*
Install/Construction (10% of Original):	*N/A*
Other (Indirect)	
Overhead (60% of all labor plus maintenance materials-EPA Cost Manual):	*unkn.*

Administration (2% of total capital investment- EPA Cost Manual):	*$35,381*
Property Taxes (1% of total capital investment- EPA Cost Manual):	*$17,691*
Insurance (1% of total capital investment- EPA Cost Manual):	*$17,691*
TOTAL INDIRECT COST:	*$70,763*
Total Annualized Direct and Indirect Costs	
TOTAL ANNUALIZED DIRECT COST:	*$196,637*
TOTAL ANNUALIZED INDIRECT COST:	*$5,141*
TOTAL ANNUALIZED COST:	*$201,778*
Cost Effectiveness	
NOx control cost(Total Annualized Costs/Annual Nox Emissions Reduced):	*$288,737*

Notes:

**NPV rough estimate from Caterpillar (rough estimate only, not a quote) September 1, 2022*

**Useful life of engines assumed to be 30 years.*

** Control % estimated based on emission standards for replacement engine.*

** Items indicated as unknown were set to zero in order to be conservative.*

** Annual interest rate max set by DAQ.*

** Annualized costs estimated by multiplying line items times the calculated capital recovery factor.*

** Capital Recovery Factor calculation is illustrated below.*

Capital Recovery Calculation :

$$\frac{\text{interest rate} \times (1+\text{interest rate})^{\text{Equipment Life}}}{[(1+\text{interest rate})^{\text{Equipment Life}}]-1}$$

Capital Recovery Factor, 30 yr =

$$\frac{0.06x(1+0.06)^{30}}{[(1+0.06)^{30}]-1} = \frac{0.34460947}{4.743491173} = 0.072648911$$

Cost Analysis for EU G009 - Replacement with 1,000kW Tier 2 Generator

Existing Source Information	
Uncontrolled Nox Emission Factor (g/kW-hr):	*14.60*
Maximum Run Time (hr/yr):	*500*
Capacity (kW):	*1250*
PTE (tons/yr):	*9.81*
5-Year Actual Average NOx (tons/yr):	*0.321*
Equipment Life, Interest, Capital Recovery Factor	
Useful Life Equipment (years):	*30*
Annual Interest Rate (%):	*0.06*
Calculated Capital Recovery Factor:	*0.0726*
Emission Reduction	
Uncontrolled Emission Factor (g/kW-hr)):	*14.60*
Tier 2 Emission Standard (incl NMVOC) (g/kW-hr):	*6.4*
5-Year Actual Average NOx (tons/yr):	*0.32*
Control Efficiency (%):	*56%*
Annual Emissions Reduced (tpy):	*0.18*
Direct Costs - Equipment, Construction	
Capital (Direct)	
NPV, Tier 2 1,000 kW engine:	*$299,500*
Material:	*incl.*
Structural Support:	*unkn.*
Construction (Direct)	
Instrumentation (10% Capital):	*$29,950*
Engineering (10% Capital):	*$29,950*
Construction and Field Cost (10% Capital):	*$29,950*
Incidental & Miscellaneous (assume 10% Engr/Comm/Labor/Equip, 10%):	*$29,950*
Delivery (5% Capital):	*$14,975*
Other (Direct)	
Taxes (8% Capital):	*$23,960*
TOTAL DIRECT COST:	*$458,235*
Indirect Costs - Operating, Maintenance	
Maintenance & Monitoring	
Maintenance & Monitoring ($/yr):	*unkn.*
Catalyst Replacement	
Catalyst Replacement:	*N/A*
Install/Construction (10% of Original):	*N/A*
Other (Indirect)	
Overhead (60% of all labor plus maintenance materials-EPA Cost Manual):	*unkn.*
Administration (2% of total capital investment-EPA Cost Manual):	*$5,990*

Property Taxes (1% of total capital investment- EPA Cost Manual):	*$2,995*
Insurance (1% of total capital investment- EPA Cost Manual):	*$2,995*
TOTAL INDIRECT COST:	*$11,980*
Total Annualized Direct and Indirect Costs	
TOTAL ANNUALIZED DIRECT COST:	*$33,290*
TOTAL ANNUALIZED INDIRECT COST:	*$870*
TOTAL ANNUALIZED COST:	*$34,161*
Cost Effectiveness	
NOx control cost(Total Annualized Costs/Annual Nox Emissions Reduced):	*$189,492*

Notes:

**NPV rough estimate from Caterpillar (rough estimate only, not a quote) September 1, 2022*

**Useful life of engines assumed to be 30 years.*

** Control % estimated based on emission standards for replacement engine.*

** Items indicated as unknown were set to zero in order to be conservative.*

** Annual interest rate max set by DAQ.*

** Annualized costs estimated by multiplying line items times the calculated capital recovery factor.*

** Capital Recovery Factor calculation is illustrated below.*

Capital Recovery Calculation :

$$\frac{\text{interest rate} \times (1+\text{interest rate})^{\wedge}\text{Equipment Life}}{[(1+\text{interest rate})^{\wedge}\text{Equipment Life}]-1}$$

Capital Recovery Factor, 30 yr =

$$= \frac{0.06x(1+0.06)^{\wedge}30}{[(1+0.06)^{\wedge}30]-1}$$

$$= \frac{0.34460947}{4.743491173}$$

$$= 0.072648911$$

Cost Analysis for EU G009 - Replacement with Tier 3 Generator

Existing Source Information	
Uncontrolled Nox Emission Factor (g/kW-hr):	*14.60*
Maximum Run Time (hr/yr):	*500*
Capacity (kW):	*1250*
PTE (tons/yr):	*9.81*
5-Year Actual Average NOx (tons/yr):	*0.321*
Equipment Life, Interest, Capital Recovery Factor	
Useful Life Equipment (years):	*30*
Annual Interest Rate (%):	*0.06*
Calculated Capital Recovery Factor:	*0.0726*
Emission Reduction	
Uncontrolled Emission Factor (g/kW-hr)):	*14.60*
Tier 3 Emission Standard (for lower capacity units) (g/kW-hr):	*4.00*
5-Year Actual Average NOx (tons/yr):	*0.32*
Control Efficiency (%):	*73%*
Annual Emissions Reduced (tpy):	*0.23*
Direct Costs - Equipment, Construction	
Capital (Direct)	
NPV, Tier 3 engine (extrapolated cost, estimated):	*$1,769,067*
Material:	*incl.*
Structural Support:	*unkn.*
Construction (Direct)	
Instrumentation (10% Capital):	*$176,907*
Engineering (10% Capital):	*$176,907*
Construction and Field Cost (10% Capital):	*$176,907*
Incidental & Miscellaneous (assume 10% Engr/Comm/Labor/Equip):	*$176,907*
Delivery (5% Capital):	*$88,453*
Other (Direct)	
Taxes (8% Capital):	*$141,525*
TOTAL DIRECT COST:	*$2,706,673*
Indirect Costs - Operating, Maintenance	
Maintenance & Monitoring	
Maintenance & Monitoring ($/yr):	*unkn.*
Catalyst Replacement	
Catalyst Replacement:	*N/A*
Install/Construction (10% of Original):	*N/A*
Other (Indirect)	
Overhead (60% of all labor plus maintenance materials-EPA Cost Manual):	*unkn.*

Administration (2% of total capital investment- EPA Cost Manual):	*$35,381*
Property Taxes (1% of total capital investment- EPA Cost Manual):	*$17,691*
Insurance (1% of total capital investment- EPA Cost Manual):	*$17,691*
TOTAL INDIRECT COST:	*$70,763*
Total Annualized Direct and Indirect Costs	
TOTAL ANNUALIZED DIRECT COST:	*$162,400*
TOTAL ANNUALIZED INDIRECT COST:	*$4,246*
TOTAL ANNUALIZED COST:	*$166,646*
Cost Effectiveness	
NOx control cost(Total Annualized Costs/Annual Nox Emissions Reduced):	*$715,076*

Notes:

**NPV rough estimate from Caterpillar (rough estimate only, not a quote) September 1, 2022*

**Useful life of engines assumed to be 30 years.*

** Control % estimated based on emission standards for replacement engine.*

** Items indicated as unknown were set to zero in order to be conservative.*

** Annual interest rate max set by DAQ.*

** Annualized costs estimated by multiplying line items times the calculated capital recovery factor.*

** Capital Recovery Factor calculation is illustrated below.*

Capital Recovery Calculation : $\dfrac{\text{interest rate x (1+interest rate) ^Equipment Life}}{\text{[(1+interest rate) ^ Equipment Life]-1}}$

Capital Recovery Factor, 30 yr = $\dfrac{0.06x(1+0.06)^{30}}{[(1+0.06)^{30}]-1}$

$= \dfrac{0.34460947}{4.743491173}$

$= 0.072648911$

Cost Analysis for EU G010 - Replacement with 1,000kW Tier 2 Generator

Existing Source Information	
Uncontrolled Nox Emission Factor (g/kW-hr):	10.16
Maximum Run Time (hr/yr):	500
Capacity (kW):	900
PTE (tons/yr):	5.64
5-Year Actual Average NOx (tons/yr):	0.437
Equipment Life, Interest, Capital Recovery Factor	
Useful Life Equipment (years):	30
Annual Interest Rate (%):	0.06
Calculated Capital Recovery Factor	0.0726
Emission Reduction	
Uncontrolled Emission Factor (g/kW-hr)):	10.16
Tier 2 Emission Standard (incl NMVOC) (g/kW-hr)	6.4
5-Year Actual Average NOx (tons/yr):	0.44
Control Efficiency (%):	37%
Annual Emissions Reduced (tpy):	0.16
Direct Costs - Equipment, Construction	
Capital (Direct)	
NPV, Tier 2 1,000kW engine:	$299,500
Material:	incl.
Structural Support:	unkn.
Construction (Direct)	
Instrumentation (10% Capital):	$29,950
Engineering (10% Capital)	$29,950
Construction and Field Cost (10% Capital):	$29,950
Incidental & Miscellaneous (assume 10% Engr/Comm/Labor/Equip):	$29,950
Delivery (5% Capital):	$14,975
Other (Direct)	
Taxes (8% Capital):	$23,960
TOTAL DIRECT COST:	$458,235
Indirect Costs - Operating, Maintenance	
Maintenance & Monitoring	
Maintenance & Monitoring ($/yr):	unkn.
Catalyst Replacement	
Catalyst Replacement:	N/A
Install/Construction (10% of Original):	N/A
Other (Indirect)	
Overhead (60% of all labor plus maintenance materials-EPA Cost Manual):	unkn.
Administration (2% of total capital investment-EPA Cost Manual):	$5,990

Property Taxes (1% of total capital investment- EPA Cost Manual):	*$2,995*
Insurance (1% of total capital investment- EPA Cost Manual):	*$2,995*
TOTAL INDIRECT COST:	*$11,980*
Total Annualized Direct and Indirect Costs	
TOTAL ANNUALIZED DIRECT COST:	*$33,290*
TOTAL ANNUALIZED INDIRECT COST:	*$870*
TOTAL ANNUALIZED COST:	*$34,161*
Cost Effectiveness	
NOx control cost(Total Annualized Costs/Annual Nox Emissions Reduced):	*$211,058*

Notes:

**NPV rough estimate from Caterpillar (rough estimate only, not a quote) September 1, 2022*

**Useful life of engines assumed to be 30 years.*

** Control % estimated based on emission standards for replacement engine.*

** Items indicated as unknown were set to zero in order to be conservative.*

** Annual interest rate max set by DAQ.*

** Annualized costs estimated by multiplying line items times the calculated capital recovery factor.*

** Capital Recovery Factor calculation is illustrated below.*

Capital Recovery Calculation : $\frac{\text{interest rate} \times (1+\text{interest rate})^{\text{Equipment Life}}}{[(1+\text{interest rate})^{\text{Equipment Life}}]-1}$

Capital Recovery Factor, 30 yr = $\frac{0.06\times(1+0.06)^{30}}{[(1+0.06)^{30}]-1}$

$= \frac{0.34460947}{4.743491173}$

$= 0.072648911$

Cost Analysis for EU G010 - Replacement with Tier 3 Generator

Existing Source Information	
Uncontrolled Nox Emission Factor (g/kW-hr):	10.16
Maximum Run Time (hr/yr):	500
Capacity (kW):	900
PTE (tons/yr):	5.64
5-Year Actual Average NOx (tons/yr):	0.437
Equipment Life, Interest, Capital Recovery Factor	
Useful Life Equipment (years):	30
Annual Interest Rate (%):	0.06
Calculated Capital Recovery Factor:	0.0726
Emission Reduction	
Uncontrolled Emission Factor (g/kW-hr)):	10.16
Tier 3 Emission Standard (for lower capacity units) (g/kW-hr):	4.00
5-Year Actual Average NOx (tons/yr):	0.44
Control Efficiency (%):	61%
Annual Emissions Reduced (tpy):	0.27
Direct Costs - Equipment, Construction	
Capital (Direct)	
NPV, Tier 3 engine (extrapolated cost, estimated):	$1,769,067
Material:	incl.
Structural Support:	unkn.
Construction (Direct)	
Instrumentation (10% Capital):	$176,907
Engineering (10% Capital):	$176,907
Construction and Field Cost (10% Capital):	$176,907
Incidental & Miscellaneous (assume 10% Engr/Comm/Labor/Equip):	$176,907
Delivery (5% Capital):	$88,453
Other (Direct)	
Taxes (8% Capital):	$141,525
TOTAL DIRECT COST:	$2,706,673
Indirect Costs - Operating, Maintenance	
Maintenance & Monitoring	
Maintenance & Monitoring ($/yr):	unkn.
Catalyst Replacement	
Catalyst Replacement:	N/A
Install/Construction (10% of Original):	N/A
Other (Indirect)	
Overhead (60% of all labor plus maintenance materials-EPA Cost Manual):	unkn.

Administration (2% of total capital investment- EPA Cost Manual):	*$35,381*
Property Taxes (1% of total capital investment- EPA Cost Manual):	*$17,691*
Insurance (1% of total capital investment- EPA Cost Manual):	*$17,691*
TOTAL INDIRECT COST:	*$70,763*
Total Annualized Direct and Indirect Costs	
TOTAL ANNUALIZED DIRECT COST:	*$162,400*
TOTAL ANNUALIZED INDIRECT COST:	*$4,246*
TOTAL ANNUALIZED COST:	*$166,646*
Cost Effectiveness	
NOx control cost(Total Annualized Costs/Annual Nox Emissions Reduced):	*$628,773*

Notes:

**NPV rough estimate from Caterpillar (rough estimate only, not a quote) September 1, 2022*

**Useful life of engines assumed to be 30 years.*

** Control % estimated based on emission standards for replacement engine.*

** Items indicated as unknown were set to zero in order to be conservative.*

** Annual interest rate max set by DAQ.*

** Annualized costs estimated by multiplying line items times the calculated capital recovery factor.*

** Capital Recovery Factor calculation is illustrated below.*

Capital Recovery Calculation : $\frac{\text{interest rate x (1+interest rate) ^Equipment Life}}{\text{[(1+interest rate) ^ Equipment Life]-1}}$

Capital Recovery Factor, 30 yr = $\frac{0.06x(1+0.06)^{30}}{[(1+0.06)^{30}]-1}$

$= \frac{0.34460947}{4.743491173}$

$= 0.072648911$

Cost Analysis for EU G032 - Replacement with 1,000kW Tier 2 Generator

Existing Source Information Per Generator	
Uncontrolled Nox Emission Factor (g/kW-hr):	*11.96*
Maximum Run Time (hr/yr):	*500*
Capacity (kW):	*1100*
PTE (tons/yr):	*7.8*
5-Year Actual Average NOx (tons/yr):	*0.528*
Equipment Life, Interest, Capital Recovery Factor	
Useful Life Equipment (years):	*30*
Annual Interest Rate (%):	*0.06*
Calculated Capital Recovery Factor:	*0.0726*
Emission Reduction Per Generator	
Uncontrolled Emission Factor (g/kW-hr)):	*11.96*
Tier 2 Emission Standard (incl NMVOC) (g/kW-hr):	*6.4*
5-Year Actual Average NOx (tons/yr):	*0.53*
Control Efficiency (%):	*46%*
Annual Emissions Reduced (tpy):	*0.25*
Direct Costs - Equipment, Construction Per Generator	
Capital (Direct)	
NPV, Tier 2 1,000kW engine:	*$299,500*
Material:	*incl.*
Structural Support:	*unkn.*
Construction (Direct)	
Instrumentation (10% Capital):	*$29,950*
Engineering (10% Capital):	*$29,950*
Construction and Field Cost (10% Capital):	*$29,950*
Incidental & Miscellaneous (assume 10% Engr/Comm/Labor/Equip):	*$29,950*
Delivery (5% Capital):	*$14,975*
Other (Direct)	
Taxes (8% Capital):	*$23,960*
TOTAL DIRECT COST:	*$458,235*
Indirect Costs - Operating, Maintenance Per Generator	
Maintenance & Monitoring	
Maintenance & Monitoring ($/yr):	*unkn.*
Catalyst Replacement	
Catalyst Replacement:	*N/A*
Install/Construction (10% of Original):	*N/A*
Other (Indirect)	
Overhead (60% of all labor plus maintenance materials-EPA Cost Manual):	*unkn.*

Administration (2% of total capital investment- EPA Cost Manual):	*$5,990*
Property Taxes (1% of total capital investment- EPA Cost Manual):	*$2,995*
Insurance (1% of total capital investment- EPA Cost Manual):	*$2,995*
TOTAL INDIRECT COST:	*$11,980*
Total Annualized Direct and Indirect Costs Per Generator	
TOTAL ANNUALIZED DIRECT COST:	*$33,290*
TOTAL ANNUALIZED INDIRECT COST:	*$870*
TOTAL ANNUALIZED COST:	*$34,161*
Cost Effectiveness Per Generator	
NOx control cost(Total Annualized Costs/Annual Nox Emissions Reduced):	*$139,148*

Notes:

**NPV rough estimate from Caterpillar (rough estimate only, not a quote) September 1, 2022*

**Useful life of engines assumed to be 30 years.*

** Control % estimated based on emission standards for replacement engine.*

** Items indicated as unknown were set to zero in order to be conservative.*

** Annual interest rate max set by DAQ.*

** Annualized costs estimated by multiplying line items times the calculated capital recovery factor.*

** Capital Recovery Factor calculation is illustrated below.*

Capital Recovery Calculation : $\frac{\text{intereste rate x (1+interest rate) ^Equipment Life}}{\text{[(1+interest rate) ^ Equipment Life]-1}}$

Capital Recovery Factor, 30 yr = $\frac{0.06x(1+0.06)^{\wedge}30}{[(1+0.06)^{\wedge}30]-1}$

$= \frac{0.34460947}{4.743491173}$

$= 0.072648911$

Cost Analysis for EU G032 - Replacement with Tier 3 Generator

Existing Source Information	
Uncontrolled Nox Emission Factor (g/kW-hr):	11.96
Maximum Run Time (hr/yr):	500
Capacity (kW):	1100
PTE (tons/yr):	7.8
5-Year Actual Average NOx (tons/yr):	0.528
Equipment Life, Interest, Capital Recovery Factor	
Useful Life Equipment (years):	30
Annual Interest Rate (%):	0.06
Calculated Capital Recovery Factor:	0.0726
Emission Reduction	
Uncontrolled Emission Factor (g/kW-hr)):	11.96
Tier 3 Emission Standard (for lower capacity units) (g/kW-hr):	4.00
5-Year Actual Average NOx (tons/yr):	0.53
Control Efficiency (%):	67%
Annual Emissions Reduced (tpy):	0.35
Direct Costs - Equipment, Construction	
Capital (Direct)	
NPV, Tier 3 engine (extrapolated cost, estimated):	$1,769,067
Material:	incl.
Structural Support:	unkn.
Construction (Direct)	
Instrumentation (10% Capital):	$176,907
Engineering (10% Capital):	$176,907
Construction and Field Cost (10% Capital):	$176,907
Incidental & Miscellaneous (assume 10% Engr/Comm/Labor/Equip):	$176,907
Delivery (5% Capital):	$88,453
Other (Direct)	
Taxes (8% Capital):	$141,525
TOTAL DIRECT COST:	$2,706,673
Indirect Costs - Operating, Maintenance	
Maintenance & Monitoring	
Maintenance & Monitoring ($/yr):	unkn.
Catalyst Replacement	
Catalyst Replacement:	N/A
Install/Construction (10% of Original):	N/A
Other (Indirect)	
Overhead (60% of all labor plus maintenance materials-EPA Cost Manual):	unkn.

Administration (2% of total capital investment- EPA Cost Manual):	$35,381
Property Taxes (1% of total capital investment- EPA Cost Manual):	$17,691
Insurance (1% of total capital investment- EPA Cost Manual):	$17,691
TOTAL INDIRECT COST:	$70,763
Total Annualized Direct and Indirect Costs	
TOTAL ANNUALIZED DIRECT COST:	$162,400
TOTAL ANNUALIZED INDIRECT COST:	$4,246
TOTAL ANNUALIZED COST:	$166,646
Cost Effectiveness	
NOx control cost(Total Annualized Costs/Annual Nox Emissions Reduced):	$474,185

Notes:

**NPV rough estimate from Caterpillar (rough estimate only, not a quote) September 1, 2022*

**Useful life of engines assumed to be 30 years.*

** Control % estimated based on emission standards for replacement engine.*

** Items indicated as unknown were set to zero in order to be conservative.*

** Annual interest rate max set by DAQ.*

** Annualized costs estimated by multiplying line items times the calculated capital recovery factor.*

** Capital Recovery Factor calculation is illustrated below.*

Capital Recovery Calculation : $\frac{\text{ntereste rate x (1+interest rate) ^Equipment Life}}{\text{[(1+interest rate) ^ Equipment Life]-1}}$

Capital Recovery Factor, 30 yr = $\frac{0.06x(1+0.06)^{30}}{[(1+0.06)^{30}]-1}$

= $\frac{0.34460947}{4.743491173}$

= 0.072648911

Cost Analysis for EU G033 - Replacement with 1,000kW Tier 2 Generator

Existing Source Information Per Generator	
Uncontrolled Nox Emission Factor (g/kW-hr):	*11.96*
Maximum Run Time (hr/yr):	*500*
Capacity (kW):	*1100*
PTE (tons/yr):	*7.8*
5-Year Actual Average NOx (tons/yr):	*0.526*
Equipment Life, Interest, Capital Recovery Factor	
Useful Life Equipment (years):	*30*
Annual Interest Rate (%):	*0.06*
Calculated Capital Recovery Factor:	*0.0726*
Emission Reduction Per Generator	
Uncontrolled Emission Factor (g/kW-hr)):	*11.96*
Tier 2 Emission Standard (incl NMVOC) (g/kW-hr):	*6.4*
5-Year Actual Average NOx (tons/yr):	*0.53*
Control Efficiency (%):	*46%*
Annual Emissions Reduced (tpy):	*0.24*
Direct Costs - Equipment, Construction Per Generator	
Capital (Direct)	
NPV, Tier 2 1,000kW engine:	*$299,500*
Material:	*incl.*
Structural Support:	*unkn.*
Construction (Direct)	
Instrumentation (10% Capital):	*$29,950*
Engineering (10% Capital):	*$29,950*
Construction and Field Cost (10% Capital):	*$29,950*
Incidental & Miscellaneous (assume 10% Engr/Comm/Labor/Equip):	*$29,950*
Delivery (5% Capital):	*$14,975*
Other (Direct)	
Taxes (8% Capital):	*$23,960*
TOTAL DIRECT COST:	*$458,235*
Indirect Costs - Operating, Maintenance Per Generator	
Maintenance & Monitoring	
Maintenance & Monitoring ($/yr):	*unkn.*
Catalyst Replacement	
Catalyst Replacement:	*N/A*
Install/Construction (10% of Original):	*N/A*
Other (Indirect)	
Overhead (60% of all labor plus maintenance materials-EPA Cost Manual):	*unkn.*

Administration (2% of total capital investment- EPA Cost Manual):	*$5,990*
Property Taxes (1% of total capital investment- EPA Cost Manual):	*$2,995*
Insurance (1% of total capital investment- EPA Cost Manual):	*$2,995*
TOTAL INDIRECT COST:	*$11,980*
Total Annualized Direct and Indirect Costs Per Generator	
TOTAL ANNUALIZED DIRECT COST:	*$33,290*
TOTAL ANNUALIZED INDIRECT COST:	*$870*
TOTAL ANNUALIZED COST:	*$34,161*
Cost Effectiveness Per Generator	
NOx control cost(Total Annualized Costs/Annual Nox Emissions Reduced):	*$139,677*

Notes:

**NPV rough estimate from Caterpillar (rough estimate only, not a quote) September 1, 2022*

**Useful life of engines assumed to be 30 years.*

** Control % estimated based on emission standards for replacement engine.*

** Items indicated as unknown were set to zero in order to be conservative.*

** Annual interest rate max set by DAQ.*

** Annualized costs estimated by multiplying line items times the calculated capital recovery factor.*

** Capital Recovery Factor calculation is illustrated below.*

Capital Recovery Calculation :
$$\frac{\text{intereste rate x (1+interest rate) \^{}Equipment Life}}{\text{[(1+interest rate) \^{} Equipment Life]-1}}$$

Capital Recovery Factor, 30 yr =
$$\frac{0.06x(1+0.06)^{30}}{[(1+0.06)^{30}]-1} = \frac{0.34460947}{4.743491173} = 0.072648911$$

Cost Analysis for EU G033- Replacement with Tier 3 Generator

Existing Source Information	
Uncontrolled Nox Emission Factor (g/kW-hr):	*11.96*
Maximum Run Time (hr/yr):	*500*
Capacity (kW):	*1100*
PTE (tons/yr):	*7.8*
5-Year Actual Average NOx (tons/yr):	*0.526*
Equipment Life, Interest, Capital Recovery Factor	
Useful Life Equipment (years):	*30*
Annual Interest Rate (%):	*0.06*
Calculated Capital Recovery Factor:	*0.0726*
Emission Reduction	
Uncontrolled Emission Factor (g/kW-hr)):	*11.96*
Tier 3 Emission Standard (for lower capacity units) (g/kW-hr):	*4.00*
5-Year Actual Average NOx (tons/yr):	*0.53*
Control Efficiency (%):	*67%*
Annual Emissions Reduced (tpy):	*0.35*
Direct Costs - Equipment, Construction	
Capital (Direct)	
NPV, Tier 3 engine (extrapolated cost, estimated):	*$1,769,067*
Material:	*incl.*
Structural Support:	*unkn.*
Construction (Direct)	
Instrumentation (10% Capital):	*$176,907*
Engineering (10% Capital):	*$176,907*
Construction and Field Cost (10% Capital):	*$176,907*
Incidental & Miscellaneous (assume 10% Engr/Comm/Labor/Equip):	*$176,907*
Delivery (5% Capital):	*$88,453*
Other (Direct)	
Taxes (8% Capital):	*$141,525*
TOTAL DIRECT COST:	*$2,706,673*
Indirect Costs - Operating, Maintenance	
Maintenance & Monitoring	
Maintenance & Monitoring ($/yr):	*unkn.*
Catalyst Replacement	
Catalyst Replacement:	*N/A*
Install/Construction (10% of Original):	*N/A*
Other (Indirect)	
Overhead (60% of all labor plus maintenance materials-EPA Cost Manual):	*unkn.*

Administration (2% of total capital investment- EPA Cost Manual):	*$35,381*
Property Taxes (1% of total capital investment- EPA Cost Manual):	*$17,691*
Insurance (1% of total capital investment- EPA Cost Manual):	*$17,691*
TOTAL INDIRECT COST:	*$70,763*
Total Annualized Direct and Indirect Costs	
TOTAL ANNUALIZED DIRECT COST:	*$162,400*
TOTAL ANNUALIZED INDIRECT COST:	*$4,246*
TOTAL ANNUALIZED COST:	*$166,646*
Cost Effectiveness	
NOx control cost(Total Annualized Costs/Annual Nox Emissions Reduced):	*$475,988*

Notes:

**NPV rough estimate from Caterpillar (rough estimate only, not a quote) September 1, 2022*

**Useful life of engines assumed to be 30 years.*

** Control % estimated based on emission standards for replacement engine.*

** Items indicated as unknown were set to zero in order to be conservative.*

** Annual interest rate max set by DAQ.*

** Annualized costs estimated by multiplying line items times the calculated capital recovery factor.*

** Capital Recovery Factor calculation is illustrated below.*

Capital Recovery Calculation : $\frac{\text{ntereste rate x (1+interest rate) ^Equipment Life}}{\text{[(1+interest rate) ^ Equipment Life]-1}}$

Capital Recovery Factor, 30 yr = $\frac{0.06x(1+0.06)^{30}}{[(1+0.06)^{30}]-1}$

$= \frac{0.34460947}{4.743491173}$

$= 0.072648911$

Appendix 3

Caesars RACT Analysis

	For DAQ Use Only
DES DEPARTMENT OF ENVIRONMENT AND SUSTAINABILITY air quality · desert conservation PROGRAM · sustainability 4701 W. Russell Road 2nd Floor Las Vegas, NV 89118-2231 Phone: (702) 455-5942 Fax: (702) 383-9994 Marci Henson, Director	

Certification Statement

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the attached document(s) are true, accurate, and complete. This certification applies to the following stationary source:

Source ID:	Source Name:
00257	CAESARS CONSOLIDATED PROPERTIES

Certification

Name of Responsible Official:	Responsible Official's Title:	Company/Organization:
JERI RUSKOWITZ	DIRECTOR ENVIRONMENTAL COMPLIANCE	CAESARS ENTERTAINMENT, INC.

Jeri L Rusk	10/3/2022
Responsible Official's Signature	**Certification Date**

Reasonably Available Control Technology Analysis
Clark County Department of Environment and Sustainability
Division of Air Quality

Caesars Entertainment, Inc.
Caesars Consolidated Properties
One Caesars Palace Drive
Las Vegas, Nevada 89109

Source ID 257

October 3, 2022

Prepared by:

BROADBENT
8 W. Pacific Avenue
Henderson, Nevada 89015

Project No. 13-01-207

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APPENDICES

1. Background

Clean Air Act (CAA) Section 181(a) includes a classification system for areas designated nonattainment for the ozone National Ambient Air Quality Standard (NAAQS). This classification system is based on the severity of the air quality as determined by the area's ozone design value and includes five categories: marginal, moderate, serious, severe and extreme. In 2018, the U.S. Environmental Protection Agency (EPA) designated hydrographic area (HA) 212 in Clark County, Nevada as nonattainment for the 2015 ozone NAAQS and assigned a classification of marginal to the area. The area was required to reach attainment of the 2015 ozone NAAQS by August 3, 2021. In July 2022, EPA determined that HA 212 failed to meet this deadline and, in addition, proposed to reclassify HA 212's attainment status classification to moderate based on its own ozone design value.

In response to this proposed EPA action, the Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ) is required to establish emissions control requirements in its State Implementation Plan (SIP) that include Reasonably Available Control Technology (RACT) requirements. RACT is defined by the EPA as "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." A RACT analysis should, therefore, consider the technological and economic impacts of controls. For example, if a certain type of emission control or emission limitation is determined to be too costly compared to the amount of emission reduction it achieves, that control might not be considered RACT. Also, as economic factors may vary by region, a control technology or emission limitation designated as meeting RACT in one location does not necessarily define RACT for another location.

The CAA requires moderate ozone nonattainment areas to implement RACT for sources of ozone forming emissions. Ozone forming emissions include volatile organic compounds (VOC) and nitrogen oxides (NO_X). More specifically, the DAQ is required to adopt RACT level controls for sources subject to an EPA Control Techniques Guidelines (CTG) document (addressing sources of VOC) and for any other major sources of VOC and NO_X. The major source threshold for an area classified as moderate is 100 tons per year and is applied to a stationary source's potential to emit (PTE) to determine whether RACT requirements need to be evaluated for any particular stationary source. DAQ has determined that it will use a stationary source's PTE as applied in the major New Source Review program and Title V (Part 70) operating permits program to identify the major stationary sources subject to RACT. In addition, DAQ has requested that each major stationary source located in HA 212 make a determination as to whether it is to be considered a major stationary source subject to a RACT evaluation and, if so, perform the evaluation and submit the evaluation to DAQ for review and inclusion in the SIP revisions required as a result of the EPA's attainment area status reclassification action.

This report summarizes the RACT analysis performed by Caesars Consolidated Properties (Caesars) and contains its source specific recommendations for RACT.

2. RACT Applicability

Caesars owns and operates several adjacent and contiguous hotels and casinos and a convention center. The specific properties reviewed for this analysis are as follows:

- Harrah's Las Vegas, 3475 S. Las Vegas Blvd.
- Flamingo Las Vegas, 3555 S. Las Vegas Blvd.

- Bally's Las Vegas, 3645 S. Las Vegas Blvd.
- Caesars Palace, 3570 S. Las Vegas Blvd.
- The Cromwell Las Vegas, 3595 S. Las Vegas Blvd.
- Paris Casino Resort, 3655 S. Las Vegas Blvd.
- The LINQ Hotel & Casino, 3535 S. Las Vegas Blvd.
- Planet Hollywood, 3667 S. Las Vegas Blvd.
- LINQ Complex - High Roller, 3545 S. Las Vegas Blvd.
- Battista's, 4041 Audrie St.
- Forum Meeting Center, 3911 Koval Lane

Consolidating all of the emissions from the various properties, Caesars currently operates as a Part 70 major stationary source according to the conditions contained in the Part 70 Operating Permit Source ID 257 issued by DAQ. A copy of the current permit is included in Appendix A. Since the Part 70 major source classification is the same as the moderate attainment area major source classification, RACT is required only if the permitted PTE for either VOC or NO_X exceeds the Part 70 major source threshold. According to the Source PTE summary contained in the facility's current Part 70 operating permit, the PTE for NO_X emissions is 440.10 tons per year and the PTE for VOC emissions is 26.76 tons per year so only NO_X emissions exceed both the Part 70 major source and moderate area major source thresholds. This analysis is therefore limited to emissions of NO_X.

3. Emission Units Subject to RACT

In their request for individual stationary source RACT analyses, DAQ further delineated the applicability requirement to a so-called Phase 1 level that includes only those individual emission units at the major stationary source with a PTE that exceeds 5 tons per year. Table 1 lists the emission units for the Caesars properties that exceed this threshold.

Table 1 – Emission Units Subject to RACT

Emission Unit ID[1]	Description	Maximum Rating	Manufacturer	Model	Fuel Type	NO_X PTE[2,3,4] (tons/year)
Harrah's Las Vegas						
HA13	Emergency Generator DOM: Pre-2006	1,232 hp 800 kW	Detroit Diesel Engine Marathon Electric Generator	81637416 573RSL205 6A-P266W	Diesel	7.39
HA14	Emergency Generator DOM: Pre-2006	890 hp 600 kW	Caterpillar Engine Caterpillar Generator	3412 SR4	Diesel	5.34
HA18	Emergency Generator DOM: 1996	1,180 hp 800 kW	Caterpillar Engine Caterpillar Generator	3412 SR-4B	Diesel	7.08

Emission Unit ID[1]	Description	Maximum Rating	Manufacturer	Model	Fuel Type	NO_X PTE[2,3,4] (tons/year)
Flamingo Las Vegas						
FL09	Emergency Generator DOM: 1999	1,109 hp 750 kW	Caterpillar Engine Caterpillar Generator	3412 SR4B	Diesel	6.66
FL10	Emergency Generator DOM: 1999	1,109 hp 750 kW	Caterpillar Engine Caterpillar Generator	3412 SR4B	Diesel	6.66
Bally's Las Vegas						
BA04	Emergency Generator (#1) DOM: Pre- 2006	1,340 hp 1,000 kW	Detroit Diesel Engine Magna One Generator	9163-7305 682FDR808 0AB-P667W	Diesel	8.04
BA05	Emergency Generator (#2) DOM: Pre- 2006	1,340 hp 1,000 kW	Detroit Diesel Engine Magna One Generator	9163-7305 682FDR808 0AB-P667W	Diesel	8.04
BA11	Emergency Generator (#3) DOM: Pre- 2006	1,340 hp 1,000 kW	Detroit Diesel Engine Detroit Diesel Generator	L18107 1000 DS	Diesel	8.04
BA12	Emergency Generator (#4) DOM: Pre- 2006	1,340 hp 1,000 kW	Detroit Diesel Engine Detroit Diesel Generator	L18127 1000 DS	Diesel	8.04
The Cromwell Las Vegas						
CR07	Diesel Engine Emergency Generator DOM: 2013	3,634 hp[5] 1,500 kW	Caterpillar Engine Caterpillar Generator	3512C SR4B-GD	Diesel	10.18
Caesars Palace						
CP01	Natural Gas Boiler	35.40 MMBtu/hr	Hurst	S4-G-800-150	Natural gas	5.46
CP02	Natural Gas Boiler	35.40 MMBtu/hr	Hurst	S4-G-800-150	Natural gas	5.46
CP03	Natural Gas Boiler	33.475 MMBtu/hr	Burnham	3P80050GB NM	Natural gas	5.35
CP04	Natural Gas Boiler	33.475 MMBtu/hr	Burnham	3P80050GB NM	Natural gas	5.35

Emission Unit ID[1]	Description	Maximum Rating	Manufacturer	Model	Fuel Type	NO_X PTE[2,3,4] (tons/year)
CP05	Natural Gas Boiler	33.475 MMBtu/hr	Burnham	3P80050GB NM	Natural gas	5.35
CP13	Emergency Generator DOM: 3/5/1997	2,876 hp 2,000 kW	Caterpillar Engine Caterpillar Generator	3516 SR-4B	Diesel	17.26
CP14	Emergency Generator DOM: 3/3/1997	2,876 hp 2,000 kW	Caterpillar Engine Caterpillar Generator	3516 SR-4B	Diesel	17.26
CP15	Emergency Generator DOM: 08/14/1996	2,520 hp 1,750 kW	Caterpillar Engine Caterpillar Generator	3516 SR-4B	Diesel	15.12
CP16	Emergency Generator DOM: 04/18/1995	1,818 hp 1,250 kW	Caterpillar Engine Caterpillar Generator	3512 SR4	Diesel	10.91
CP17	Emergency Generator DOM: 12/10/1997	2,876 hp 2,000 kW	Caterpillar Engine Caterpillar Generator	3516 SR-4B	Diesel	17.26
CP28	Emergency Generator DOM: 2008	3,634 hp[5] 2,000 kW	Caterpillar Engine Caterpillar Generator	3516CDITA SR4B HV	Diesel	10.47
CP29	Emergency Generator DOM: 2008	3,634 hp[5] 2,000 kW	Caterpillar Engine Caterpillar Generator	3516CDITA SR4B HV	Diesel	10.47
Paris Casino Resort						
PA17	Emergency Generator #1 DOM: 03/25/1998	2,816 hp 2,100 kW	Cummins Engine Cummins Generator	CW-73-G QSW73	Diesel	16.90
PA18	Emergency Generator #2 DOM: 02/26/1998	2,816 hp 2,100 kW	Cummins Engine Cummins Generator	CW-73-G QSW73	Diesel	16.90

Emission Unit ID[1]	Description	Maximum Rating	Manufacturer	Model	Fuel Type	NO_X PTE[2,3,4] (tons/year)
The LINQ Hotel and Casino						
IP08	Emergency Generator DOM: Pre-2006	890 hp 600 kW	Caterpillar Engine Caterpillar Generator	3412 SR4	Diesel	5.34
IP09	Emergency Generator DOM: Pre-2006	890 hp 600 kW	Caterpillar Engine Caterpillar Generator	3412 SR4	Diesel	5.34
Planet Hollywood						
PH10	Emergency Generator DOM: 1999	2,550 hp 1,750 kW	MTU/Detroit Diesel Engine Spectrum Generator	T1637K16 1750DS4	Diesel	15.30
PH11	Emergency Generator DOM: 1999	2,550 hp 1,750 kW	MTU/Detroit Diesel Engine Spectrum Generator	T1637K16 1750DS4	Diesel	15.30
PH12	Emergency Generator DOM: 1999	2,550 hp 1,750 kW	MTU/Detroit Diesel Engine Spectrum Generator	T1637K16 1750DS4	Diesel	15.30
PH13	Emergency Generator DOM: 2008	2,561 hp 1,750 kW	MTU/Detroit Diesel Engine MTU Generator	T1238A36 1750RXC6D T2	Diesel	6.40
LINQ Complex						
LI06	Emergency Generator DOM: 2012	3,634 hp[5] 2,000 kW	Caterpillar Engine Caterpillar Generator	3516C SR4B-GD	Diesel	10.80
LI07	Emergency Generator DOM: 2012	3,634 hp[5] 2,000 kW	Caterpillar Engine Caterpillar Generator	3516C SR4B-GD	Diesel	10.80

Notes: [1] Emission Unit ID from Part 70 Operating Permit Tables III-A-1, B-1, C-1, D-1, E-1, F-1, G-1, H-1 and I-1
[2] PTE from Part 70 Operating Permit Tables III-A-2, B-2, C-2, D-2, E-2, F-2, G-2, H-2 and I-2

[3] Emissions for emergency generators based on 500 hours per year operation and an AP-42 emission factor except for EU's CR07, CP28, CP29, PH13, LI06 and LI07 which are based on manufacturer's specifications.
[4] Emissions for boilers based on 8,760 hours per year operation and emission factors derived from exhaust gas NO_X concentration limits.
[5] Based on manufacturer's performance data, the actual hp for these engines ranges from 2,206 hp (1,500 kW) to 2,937 hp (2,000 kW).

Each boiler listed in Table 1 has emission limits for exhaust gas NO_X concentrations in ppm. These additional limitations are summarized in Table 2.

Table 2 – Boiler Emission Unit Emissions Limitations

Emission Unit ID	Fuel Type	NO_X Concentration (ppm)	NO_X Emission Rate (lb/hr)
CP01	Natural gas	29 @ 3% O_2	1.24
CP02	Natural gas	29 @ 3% O_2	1.24
CP03	Natural gas	30 @ 3% O_2	1.23
CP04	Natural gas	30 @ 3% O_2	1.23
CP05	Natural gas	30 @ 3% O_2	1.23

Each boiler is subject to performance testing every 5 years and must perform burner efficiency testing semiannually.

Emergency generators do not have specific emission limits. The permit contains general operation and maintenance requirements as follows:

- The permittee shall operate and maintain all diesel generators and fire pumps in accordance with the manufacturer's O&M manual for emissions-related components
- The permittee shall operate each of the diesel engines with turbochargers and aftercoolers

Engines subject to 40 CFR Part 60, Subpart IIII are also required to ensure that the diesel engines are in compliance with the regulation by meeting the following:

- Operation of the engine according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer
- Installation and configuration of the engine according to the manufacturer's specifications

In addition, each emergency generator is limited to 100 hours of operation for testing and maintenance annually.

Actual emissions of NO_X for the entire source and each emission unit for calendar years 2019-2021 are summarized in Table 3.

Table 3 – Actual NO_X Emissions 2019-2021

Emission Unit ID	Actual NO_X Emissions[1,2] (tons)			Maximum Annual 2019-2021 (tons)	NO_X PTE (tons/year)	Maximum Annual/PTE
	2019	2020	2021			
Entire Source	21.51	18.55	40.17	40.17	440.11	9.1%
HA13	0.21	0.20	0.20	0.21	7.39	2.8%
HA14	0.21	0.19	0.25	0.25	5.34	4.7%
HA18	0.29	0.24	0.34	0.34	7.08	4.8%
FL09	0.12	0.11	0.28	0.28	6.66	4.2%
FL10	0.08	0.11	0.12	0.12	6.66	1.8%
BA04	0.24	0.19	0.20	0.24	8.04	3.0%
BA05	0.26	0.20	0.20	0.26	8.04	3.2%
BA11	0.19	0.14	0.14	0.19	8.04	2.4%
BA12	0.22	0.14	0.19	0.22	8.04	2.7%
CR07	0.21	0.19	0.19	0.21	10.18	2.1%
CP01	1.58	2.23	0.29	2.23	5.46	40.8%
CP02	2.74	2.04	2.09	2.74	5.46	50.2%
CP03	2.35	0.39	1.20	2.35	5.35	43.9%
CP04	0.45	1.08	0.88	1.08	5.35	20.2%
CP05	1.73	1.08	2.49	2.49	5.35	46.5%
CP13	0.70	0.67	0.88	0.88	17.26	5.1%
CP14	0.74	0.67	0.92	0.92	17.26	5.3%
CP15	0.60	0.52	0.78	0.78	15.12	5.2%
CP16	0.43	0.36	0.67	0.67	10.91	6.1%
CP17	0.70	0.63	1.04	1.04	17.26	6.0%
CP28	0.56	0.39	0.52	0.56	10.47	5.3%
CP29	0.52	0.40	0.56	0.56	10.47	5.3%
PA17	0.32	0.45	0.34	0.45	16.9	2.7%
PA18	0.20	0.00	0.00	0.20	16.9	1.2%
IP08	0.14	0.15	0.22	0.22	5.34	4.1%
IP09	0.14	0.14	0.23	0.23	5.34	4.3%
PH10	-	-	0.30	0.30	15.3	2.0%
PH11	-	-	0.24	0.24	15.3	1.6%
PH12	-	-	0.26	0.26	15.3	1.7%
PH13	-	-	0.13	0.13	6.4	2.0%
LI06	0.03	0.16	0.26	0.26	10.8	2.4%
LI07	0.03	0.06	0.21	0.21	10.8	1.9%

Notes: [1] Entire source actual emissions based on 2019, 2020 and 2021 Emissions Inventories. Individual emission unit actual emissions based on maximum hourly emission rates and actual hours of operation.
[2] Includes emergency operations for generators.

As shown in Table 3, maximum actual emissions for the entire source are only 9.1% of the entire sources' PTE. Individual emission units' maximum actual emissions are between 20% and 50% of PTE for the boilers and between 1% and 6% for the emergency generators.

Actual hours of operation for each emission unit for calendar years 2019-2021 are summarized in Table 4.

Table 4 – Actual Hours of Operation 2019-2021

Emission Unit ID	Actual Operation (hours)					
	2019		2020		2021	
	Operation Normal	Operation Emergency	Operation Normal	Operation Emergency	Operation Normal	Operation Emergency
HA13	14.53	0.00	13.37	0.00	13.45	0.00
HA14	19.95	0.00	17.80	0.00	23.70	0.00
HA18	20.40	0.00	17.25	0.00	24.20	0.00
FL09	8.91	0.00	8.00	0.00	6.00	15.00
FL10	5.90	0.00	8.00	0.00	7.00	0.00
BA04	14.75	0.00	11.50	0.00	12.70	0.00
BA05	16.25	0.00	12.30	0.00	12.40	0.00
BA11	11.65	0.00	8.60	0.40	8.40	0.00
BA12	13.95	0.00	8.20	0.40	11.60	0.00
CR07	8.60	1.25	8.80	0.30	9.30	0.00
CP01	2523.80	na	3569.60	na	446.60	na
CP02	4384.50	na	3264.20	na	3233.20	na
CP03	3963.00	na	653.20	na	1962.00	na
CP04	764.20	na	1822.80	na	1436.90	na
CP05	2923.50	na	1832.90	na	4082.10	na
CP13	20.40	0.00	19.40	0.00	25.30	0.40
CP14	21.40	0.00	19.40	0.00	26.30	0.40
CP15	19.90	0.00	17.20	0.00	25.30	0.40
CP16	19.80	0.00	16.40	0.00	28.20	2.30
CP17	20.40	0.00	18.30	0.00	29.00	0.40
CP28	26.60	0.00	18.90	0.00	24.30	0.30
CP29	24.20	0.00	19.00	0.00	26.10	0.40
PA17	9.55	0.00	13.30	0.00	10.05	0.00
PA18	5.90	0.00	0.00	0.00	0.00	0.00
IP08	13.00	0.00	14.25	0.00	20.90	0.00
IP09	13.00	0.00	13.00	0.00	21.15	0.00
PH10	-	-	-	-	9.80	0.00
PH11	-	-	-	-	7.80	0.00
PH12	-	-	-	-	8.60	0.00
PH13	-	-	-	-	10.00	0.00
LI06	1.20	0.00	7.40	0.00	12.10	0.00
LI07	1.20	0.00	2.80	0.00	9.90	0.00

The boilers operate year-round with the most use occurring during the months of December through March. The emergency generators also operate year-round. In addition, operation of the emergency generators is almost exclusively related to testing and maintenance which must be performed on a routine monthly basis.

4. RACT Analysis

The RACT analysis consists of various steps:

- Identification of existing equipment and baseline emissions
- Identification of available control options
- Elimination of technically infeasible control options
- Determination of the cost effectiveness of control options
- Evaluation of the benefits and disadvantages (environmental, energy and economic) associated with the technically feasible control options
- Identification of RACT control technology including emission limitations, monitoring, testing, recordkeeping and reporting requirements

RACT emissions limitations can take various forms depending on the type of source and as long as the emissions limitations achieve the required emissions reductions and are legally and practically enforceable through appropriate monitoring, recordkeeping and reporting requirements. In addition, RACT is a continuous emissions reduction requirement and must apply over the range of operations [steady-state, startup, shutdown, and malfunctions (SSM)]; however, RACT can include alternative emissions limitations or work practices for SSM.

For uniformity of comparison, DAQ has requested that major sources use a 6% interest rate to compute costs. This rate was used in all cost analyses contained in this report.

Regarding the base case for emissions, DAQ has stated that, if a major source's actual emissions over three consecutive, representative years are less than 70% of the major source's PTE, then the major source can elect to use actual emissions for the base case. Since this is the case for Caesars, the maximum actual annual emissions will be used for each emission unit evaluated for RACT in this report.

A detailed RACT analysis for each emission unit subject to RACT review identified above is included in Appendices B, and C.

5. Results

The results of each RACT determination are discussed in Section 3.0 of Appendices B and C. It should be noted that emission units that had similar ratings and/or emission concentrations were grouped for RACT determination purposes.

Appendix A
Part 70 Operating Permit

DES
DEPARTMENT OF ENVIRONMENT AND SUSTAINABILITY

4701 W. Russell Rd Suite 200
Las Vegas, NV 89118-2231
Phone (702) 455-5942
Fax (702) 383-9994

PART 70 OPERATING PERMIT

SOURCE ID: 257

Caesars Entertainment, Inc.,
Caesars Consolidated Properties

Harrah's Las Vegas, 3475 S. Las Vegas Blvd.
Flamingo Las Vegas, 3555 S. Las Vegas Blvd.
Bally's Las Vegas, 3645 S. Las Vegas Blvd.
Caesars Palace, 3570 S. Las Vegas Blvd.
The Cromwell Las Vegas, 3595 S. Las Vegas Blvd.
Paris Casino Resort, 3655 S. Las Vegas Blvd.
The LINQ Hotel & Casino, 3535 S. Las Vegas Blvd.
Planet Hollywood, 3667 S. Las Vegas Blvd.
LINQ Complex - High Roller, 3545 S. Las Vegas Blvd.
Battista's, 4041 Audrie St.
Forum Meeting Center, 3911 Koval Lane

ISSUED ON: September 23, 2021 **EXPIRES ON: September 22, 2026**

Revised: May 12, 2022

Current Action: Administrative Revision

Issued to:
Caesars Entertainment, Inc.
One Caesars Palace Drive
Las Vegas, Nevada 89109

Responsible Official:
Eric Dominguez
SVP Engineering & Asset Mgt.
PHONE: (702) 343-9501 FAX: (702) 407-6456
EMAIL: edominguez@caesars.com

NATURE OF BUSINESS:
SIC code 7011, "Hotels and Motels"
NAICS code 721120, "Casino Hotels"

Issued by the Clark County Department of Environment and Sustainability, Division of Air Quality in accordance with Section 12.5 of the Clark County Air Quality Regulations.

Theodore A. Lendis, Permitting Manager

EXECUTIVE SUMMARY

Caesars Consolidated Properties (Caesars) is a major stationary source for nitrogen oxides (NO_x), a major Part 70 source for carbon monoxide (CO), and a minor source for particulate matter less than 10 microns in diameter (PM_{10}), particulate matter less than 2.5 microns in diameter ($PM_{2.5}$), sulfur oxides (SO_x), volatile organic compounds (VOCs), and hazardous air pollutants (HAPs). The source is also identified as a major source of greenhouse gases (GHGs). It is located on 1 Caesars Palace Drive, Las Vegas, Nevada, in the Las Vegas Valley airshed (Hydrographic Area (HA) 212). HA 212 is in attainment for all regulated air pollutants except ozone; effective August 3, 2018, the U.S. Environmental Protection Agency (EPA) designated HA 212 in marginal nonattainment for the 2015 ozone National Ambient Air Quality Standard (NAAQS). HA 212 is also subject to a maintenance plan for the CO and PM_{10} NAAQS.

Caesars owns and operates several adjacent and contiguous hotels and casinos and a convention center grouped under SIC code 7011, "Hotels and Motels" (NAICS code 721120, "Casino Hotels"). The source is operating eleven facilities: Harrah's Las Vegas, Flamingo Las Vegas, Bally's Las Vegas, The Cromwell Las Vegas, Caesars Palace, Paris Casino Resort, The LINQ Hotel & Casino, Planet Hollywood, LINQ Complex – High Roller, Battista's, and the Forum Meeting Center. Caesars is not classified as a categorical Stationary Source, as defined in Section 12.2.2(j) of the Clark County Air Quality Regulations (AQRs).

The table below summarizes the source-wide potential to emit (PTE) for each regulated air pollutant.

Source PTE (tons per year)

PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP	GHG
68.99	68.99	440.11	186.53	2.28	26.76	6.03	288,439.90

The Clark County Department of Environment and Sustainability (DES), Division of Air Quality (DAQ), issued a renewal Part 70 Operating Permit (OP) on March 28, 2016, with revisions issued on October 10, 2016; May 5, 2017; December 2, 2018; December 19, 2019; and June 23, 2021. This permitting action is based on all the revisions listed above, and the renewal application submitted on September 25, 2020.

Pursuant to AQR 12.5, all terms and conditions in Sections I–VII and the attachment in this permit are federally enforceable unless explicitly denoted otherwise.

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LIST OF TABLES

I. ACRONYMS

Table I-1: List of Acronyms

Term	Description
AQR	Clark County Air Quality Regulations
AST	aboveground storage tank
ATC	Authority to Construct
CARB	California Air Resources Board
CE	control efficiency
CF	control factor
CFR	United States Code of Federal Regulations
CO	carbon monoxide
EF	emission Factor
EMP	Environmental Management Portal
EO	Executive Order
EPA	United States Environmental Protection Agency
EU	emission unit
EVR	enhanced vapor recovery
FGR	flue gas recirculation
GDO	gasoline dispensing operation
HAP	hazardous air pollutant
hp	horsepower
kW	kilowatt
MMBtu	millions of British thermal units
NAC	Nevada Administrative Code
NO_X	nitrogen oxides
NESHAP	National Emission Standards for Hazardous Air Pollutants
NRS	Nevada Revised Statutes
NSPS	New Source Performance Standards
NSR	New Source Review
OP	Operating Permit
PM_{10}	particulate matter less than 10 microns
ppm	parts per million
PSD	Prevention of Significant Deterioration
PTE	potential to emit
scf	standard cubic feet
SIP	State Implementation Plan
SO_X	sulfur oxides
TSD	Technical Support Document
UST	underground storage tank
USGS	United States Geological Survey
UTM	Universal Transverse Mercator
VOC	volatile organic compound

II. GENERAL CONDITIONS

A. GENERAL REQUIREMENTS

1. The permittee shall comply with all conditions of the Part 70 Operating Permit (OP). Any permit noncompliance may constitute a violation of the Clark County Air Quality Regulations (AQRs), Nevada law, and the Clean Air Act (Act), and is grounds for enforcement action; permit termination, revocation and reissuance, or revision; or denial of a permit renewal application. *[AQR 12.5.2.6(g)(1)]*

2. If any term or condition of this permit becomes invalid as a result of a challenge to a portion of this permit, the other terms and conditions of this permit shall not be affected and shall remain valid. *[AQR 12.5.2.6(f)]*

3. The permittee shall pay all permit fees pursuant to AQR 18. *[AQR 12.5.2.6(h)]*

4. This permit does not convey any property rights of any sort, or any exclusive privilege. *[AQR 12.5.2.6(g)(4)]*

5. The permittee agrees to allow inspection of the premises to which this permit relates by any authorized representative of the Control Officer at any time during the permittee's hours of operation without prior notice. The permittee shall not obstruct, hamper, or interfere with any such inspection. *[AQR 4.1; AQR 5.1.1; & AQR 12.5.2.8(b)]*

6. The permittee shall allow the Control Officer, upon presentation of credentials, to: *[AQR 4.1 & AQR 12.5.2.8(b)]*

   a. Access and copy any records that must be kept under the conditions of the permit;

   b. Inspect any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit;

   c. Sample or monitor substances or parameters for the purpose of assuring compliance with the permit or applicable requirements; and

   d. Document alleged violations using such devices as cameras or video equipment.

7. Any permittee who fails to submit any relevant facts, or who has submitted incorrect information in a permit application, shall, upon becoming aware of such failure or incorrect submittal, promptly submit to DAQ such supplementary facts or corrected information. In addition, the permittee shall also provide any additional information as necessary to address any requirements that become applicable to the source after the date a complete application was filed but before the release of a draft permit. A responsible official shall certify the additional information, consistent with the requirements of AQR 12.5.2.4. *[AQR 12.5.2.2]*

8. Anyone issued a permit under AQR 12.5 shall post it in a location that is clearly visible and accessible to facility employees and DAQ representatives. *[AQR 12.5.2.6(m)]*

B. MODIFICATION, REVISION, RENEWAL REQUIREMENTS

1. No person shall begin actual construction of a New Part 70 source, or modify or reconstruct an existing Part 70 source that falls within the preconstruction review applicability criteria, without first obtaining an Authority to Construct (ATC) Permit from the Control Officer *[AQR 12.4.1.1(a)]*

2. This permit may be revised, revoked, reopened and reissued, or terminated for cause by the Control Officer. The filing of a request by the permittee for a permit revision, revocation, reissuance, or termination, or of a notification of planned changes or anticipated noncompliance, does not stay any permit condition. *[AQR 12.5.2.6(g)(3)]*

3. The permit shall be reopened under any of the following circumstances and when all applicable requirements pursuant to AQR 12.5.2.15 are met: *[AQR 12.5.2.15(a)]*

    a. New applicable requirements become applicable to a stationary source considered "major" (per the definition in AQR 12.2, AQR 12.3, or 40 CFR Part 70.3(a)(1)) with a remaining permit term of three or more years;

    b. Additional requirements (including excess emissions requirements) become applicable to an affected source under the Acid Rain Program;

    c. The Control Officer or U.S. Environmental Protection Agency (EPA) determines that the permit contains a material mistake, or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit; or

    d. The EPA Administrator or the Control Officer determines that the permit must be revised or revoked to assure compliance with applicable requirements.

4. A permit, permit revision, or renewal may be approved only if all of the following conditions have been met: *[AQR 12.5.2.10(a)]*

    a. The permittee has submitted to the Control Officer a complete application for a permit, permit revision, or permit renewal, except that a complete application need not be received before a Part 70 general permit is issued pursuant to AQR 12.5.2.20; and

    b. The conditions of the permit provide for compliance with all applicable requirements and the requirements of AQR 12.5.

5. The permittee shall not build, erect, install, or use any article, machine, equipment, or other contrivance, the use of which, without resulting in a reduction in the total release of air contaminants to the atmosphere, reduces or conceals an emission that would otherwise constitute a violation of an applicable requirement. *[AQR 80.1 & 40 CFR Part 60.12]*

6. No permit revisions shall be required under any approved economic incentives, marketable permits, emissions trading, and other similar programs or processes for changes that are provided for in the permit. *[AQR 12.5.2.6(i)]*

7. Permit expiration terminates the permittee's right to operate unless a timely and complete renewal application has been submitted. *[AQR 12.5.2.11(b)]*

8. For purposes of permit renewal, a timely application is a complete application that is submitted at least six months, but not more than eighteen months, prior to the date of permit expiration. If a source submits a timely application under this provision, it may continue operating under its current Part 70 Operating Permit (OP) until final action is taken on its application for a renewed Part 70 OP. *[AQR 12.5.2.1(a)(2)]*

C. REPORTING, NOTIFICATIONS, AND INFORMATION REQUIREMENTS

1. The permittee shall submit all compliance certifications to EPA and to the Control Officer. *[AQR 12.5.2.8(e)(4)]*

2. Any application form, report, or compliance certification submitted to the Control Officer pursuant to the OP or AQRs shall contain a certification by a responsible official, with an original signature, of truth, accuracy, and completeness. This certification (and any other certification required under AQR 12.5) shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. *[AQR 12.5.2.6(l)]*

3. The permittee shall furnish to the Control Officer, in writing and within a reasonable time, any information that the Control Officer may request to determine whether cause exists for revising, revoking and reissuing, or terminating the permit, or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Control Officer copies of records the permit requires keeping. The permittee may furnish records claimed to be confidential directly to the Administrator, along with a claim of confidentiality. *[AQR 12.5.2.6(g)(5)]*

4. Upon request of the Control Officer, the permittee shall provide information or analyses that will disclose the nature, extent, quantity, or degree of air contaminants that are or may be discharged by the source, along with the type or nature of control equipment in use. The Control Officer may require that such disclosures be certified by a professional engineer registered in the state. In addition to this report, the Control Officer may designate an authorized agent to make an independent study and report on the nature, extent, quantity, or degree of any air contaminants that are or may be discharged from the source. An agent so designated is authorized to inspect any article, machine, equipment, or other contrivance necessary to make the inspection and report. *[AQR 4.1]*

5. The permittee shall submit annual emissions inventory reports based on the following: *[AQR 18.6.1 and AQR 12.5.2.4]*

    a. The annual emissions inventory must be submitted to DAQ by March 31 of each calendar year (if March 31 falls on a Saturday or Sunday, or on a federal or Nevada holiday, the submittal shall be due on the next regularly scheduled business day);

    b. The calculated actual annual emissions from each emission unit shall be reported, even if there was no activity, along with the total calculated actual annual emissions for the source based on the emissions calculation methodology used to establish the PTE in the permit or an equivalent method approved by the Control Officer prior to submittal; and

c. As the first page of text, a signed certification containing the sentence: "I certify that, based on information and belief formed after reasonable inquiry, the statements contained in this document are true, accurate, and complete." This statement shall be signed and dated by a responsible official of the company (a sample form is available from DAQ).

6. Stationary sources that emit 25 tons or more of nitrogen oxide (NO_X) and/or emit 25 tons or more of volatile organic compounds (VOC) from their emission units, insignificant activities and exempt activities during a calendar year shall submit an annual emissions statement for both pollutants. Emissions statements must include actual annual NO_X and VOC emissions from all activities, including emission units, insignificant activities and exempt activities. Emissions statements are separate from, and additional to, the calculated annual emissions reported each year for all regulated air pollutants (aka Emissions Inventory). *[AQR 12.9.1]*

7. All report submissions shall be addressed to the attention of the Control Officer. *[AQR 12.5.2.6(d) & AQR 12.5.2.8]*

8. All reports shall contain the following: *[AQR 12.5.2.6(d) & AQR 12.5.2.8]*

   a. A certification statement on the first page, e.g., "I certify that, based on information and belief formed after reasonable inquiry, the statements contained in this document are true, accurate and complete." (A sample form is available from DAQ.)

   b. A certification signature from a responsible official of the company and the date of certification.

9. The permittee shall submit semiannual monitoring reports to DAQ. *[AQR 12.5.2.6(d) & AQR 12.5.2.8]*

10. The following requirements apply to semiannual reports: *[AQR 12.5.2.6(d) & AQR 12.5.2.8]*

    a. The report shall include a semiannual summary of each item listed in Sections III.A.7.b, III.B.7.b, III.C.7.b, III.D.7.b, III.E.7.b, III.F.7.b, III.G.7.b, III.H.7.b, III.I.7.b, III.J.7.b, and III.K.7.b of this OP.

    b. The report shall be based on a calendar semiannual period, which includes partial reporting periods.

    c. The report shall be received by DAQ within 30 calendar days after the semiannual period.

11. Regardless of the date of issuance of this OP, the source shall comply with the schedule for report submissions outlined in Table II-C-1. *[AQR 12.5.2.6(d) & AQR 12.5.2.8]*

Table II-C-1: Required Submission Dates for Various Reports

Required Report	Applicable Period	Due Date
Semiannual report for 1st six-month period	January, February, March, April, May, June	July 30 each year[1]
Semiannual report for 2nd six-month period; any additional annual records required	July, August, September, October, November, December	January 30 each year[1]
Annual Compliance Certification	Calendar year	January 30 each year[1]
Annual Emission Inventory Report	Calendar year	March 31 each year[1]
Annual Emission Statement[2]	Calendar year	March 31 each year[1]
Notification of Malfunctions, Startup, Shutdowns, or Deviations with Excess Emission	As required	Within 24 hours of the permittee learns of the event
Report of Malfunctions, Startup, Shutdowns, or Deviations with Excess Emission	As required	Within 72 hours of the notification
Deviation Report without Excess Emissions	As required	Along with semiannual reports[1]
Excess Emissions that Pose a Potential Imminent and Substantial Danger	As required	Within 12 hours of the permittee learns of the event
Performance Testing Protocol	As required	No less than 45 days, but no more than 90 days, before the anticipated test date[1]
Performance Testing	As required	Within 60 days of end of test[1]

[1] If the due date falls on a Saturday, Sunday, or federal or Nevada holiday, the submittal is due on the next regularly scheduled business day.
[2] Required only for stationary sources that emit 25 tons or more of nitrogen oxide (NO_X) and/or emit 25 tons or more of volatile organic compounds (VOC) during a calendar year.

12. The Control Officer reserves the right to require additional reports and reporting to verify compliance with permit emission limits, applicable permit requirements, and requirements of applicable federal regulations. *[AQR 4.4]*

D. COMPLIANCE REQUIREMENTS

1. The permittee shall not use as a defense in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. *[AQR 12.5.2.6(g)(2)]*

2. Any person who violates any provision of the AQRs, including, but not limited to, any application requirement; any permit condition; any fee or filing requirement; any duty to allow or carry out inspection, entry, or monitoring activities; or any other DAQ requirements is guilty of a civil offense and shall pay a civil penalty levied by the Air Pollution Control Hearing Board and/or the Hearing Officer of not more than $10,000. Each day of violation constitutes a separate offense. *[AQR 9.1 & NRS 445B.640]*

3. Any person aggrieved by an order issued pursuant to AQR 9.1 is entitled to a review, as provided in Chapter 233B of the Nevada Revised Statutes. *[AQR 9.12]*

4. The permittee shall comply with the requirements of 40 CFR Part 61, Subpart M—the National Emission Standard for Asbestos—for all demolition and renovation projects. *[AQR 13.1(b)(8)]*

5. The permittee shall certify compliance with the terms and conditions contained in the Part 70 OP, including emission limitations, standards, work practices, and the means for monitoring such compliance. *[AQR 12.5.2.8(e)]*

6. The permittee shall submit compliance certifications annually in writing to the Control Officer (4701 W. Russell Road, Suite 200, Las Vegas, Nevada 89118) and the Region 9 Administrator (Director, Air and Radiation Divisions, 75 Hawthorne St., San Francisco, California 94105). A compliance certification for each calendar year will be due on January 30 of the following year, and shall include the following: *[AQR 12.5.2.8(e)]*

    a. The identification of each term or condition of the permit that is the basis of the certification;

    b. The identification of the methods or other means used by the permittee for determining the compliance status with each term and condition during the certification period. The methods and means shall include, at a minimum, the monitoring and related recordkeeping and reporting requirements described in 40 CFR Part 70.6(a)(3). If necessary, the permittee shall also identify any other material information that must be included in the certification to comply with Section 113(c)(2) of the Act, which prohibits knowingly making a false certification or omitting material information; and

    c. The status of compliance with the terms and conditions of the permit for the period covered by the certification, including whether compliance during the period was continuous or intermittent. The certification shall be based on the methods or means designated in (b) above, and shall identify each deviation and take it into account in the compliance certification. The certification shall also identify, as possible exceptions to compliance, any periods during which compliance is required and in which an excursion or exceedance, as defined under 40 CFR Part 64, occurred.

7. The permittee shall report to the Control Officer any startup, shutdown, malfunction, emergency, or deviation that causes emissions of regulated air pollutants in excess of limits set by regulations or this permit. The report shall be in two parts: *[AQR 12.5.2.6(d)(4)(B) & AQR 25.6.1]*

    a. Within 24 hours of the time the permittee learns of the excess emissions, the permittee shall notify DAQ by phone at (702) 455-5942, by fax at (702) 383-9994, or by email at airquality@clarkcountynv.gov.

    b. Within 72 hours of the notification required by paragraph (a) above, the permittee shall submit a detailed written report to DAQ containing the information required by AQR 25.6.3.

8. With the semiannual monitoring report, the permittee shall report to the Control Officer all deviations from permit conditions that do not result in excess emissions, including those attributable to malfunction, startup, or shutdown. Reports shall identify the probable cause of each deviation and any corrective actions or preventative measures taken. *[AQR 12.5.2.6(d)(4)(B)]*

9. The owner or operator of any source required to obtain a permit under AQR 12 shall report to the Control Officer any emissions in excess of an applicable requirement or emission limit that pose a potential imminent and substantial danger to public health and safety or the environment as soon as possible, but no later than 12 hours after the deviation is discovered, and submit a written report within two days of the occurrence. *[AQR 25.6.2]*

E. PERFORMANCE TESTING REQUIREMENTS

1. Upon request of the Control Officer, the permittee shall test or have tests performed to determine the emissions of air contaminants from any source whenever the Control Officer has reason to believe that an emission in excess of that allowed by the AQRs is occurring. The Control Officer may specify testing methods to be used in accordance with good professional practice, and may observe the testing. All tests shall be conducted by reputable, qualified personnel. *[AQR 4.2]*

2. Upon request of the Control Officer, the permittee shall provide necessary holes in stacks or ducts and such other safe and proper sampling and testing facilities, exclusive of instruments and sensing devices, as may be necessary for proper determination of the emission of air contaminants. *[AQR 4.2]*

3. The permittee shall submit to the Control Officer for approval a performance testing protocol that contains testing, reporting, and notification schedules, test protocols, and anticipated test dates no less than 45 days, but no more than 90 days, prior to the anticipated date of the performance test, unless otherwise specified in Sections, III.B.6, II.C.6, III.E.6, III.F.6, III.G.6, or III.H.6 of this permit. *[AQR 12.5.2.8]*

4. The permittee shall submit to EPA for approval any alternative test methods EPA has not already approved to demonstrate compliance with a requirement under 40 CFR Part 60. *[40 CFR Part 60.8(b)]*

5. The permittee shall submit a report describing the results of each performance test to the Control Officer within 60 days of the end of the test. *[AQR 12.5.2.8]*

III. EMISSION UNITS AND APPLICABLE REQUIREMENTS

A. HARRAH'S LAS VEGAS

1. Emission Units

a. The stationary source activities at Harrah's Las Vegas covered by this Part 70 OP consist of the emission units (EUs) and associated appurtenances summarized in Table III-A-1. *[AQR 12.5.2.3; NSR ATC, Modification 10, Revision 0 (12/15/2008); NSR ATC, Modification 12, Revision 1 (08/20/2009); Title V 70 OP (03/28/2016) and (12/03/2018); and Application for Renewal of Part 70 OP (09/25/2020)]*

Table III-A-1: Summary of EUs – Harrah's Las Vegas

EU	Description	Rating	Make	Model No.	Serial No.
HA06	Natural Gas Boiler	4.50 MMBtu/hr	Bryan	RV450-S-150-FDG	66726 (#5)
HA07	Natural Gas Boiler	9.0 MMBtu/hr	Bryan	LM900-S-15-FDG	66665 (#4)
HA08	Natural Gas Boiler	8.369 MMBtu/hr	Cleaver Brooks	CB.200-200	L-70272 (#1)
HA09	Natural Gas Boiler	8.369 MMBtu/hr	Cleaver Brooks	CB.200-200	L-70271 (#2)
HA10	Natural Gas Boiler	8.369 MMBtu/hr	Cleaver Brooks	CB.200-200	L-70270 (#3)
HA11	Natural Gas Boiler	4.80 MMBtu/hr	Universal Energy	BF108C	10341-1 (#6)
HA12	Emergency Fire Pump DOM: Pre-2006	276 kW	Fairbanks Morse Pump	5922F	3T1-020216
		370 hp	Caterpillar Engine	3406BD1	6TB06046
HA13	Emergency Generator DOM: Pre-2006	800 kW	Marathon Electric Generator	573RSL2056A-P266W	VE3575357
		1,232 hp	Detroit Diesel Engine	81637416	16VF007962
HA14	Emergency Generator DOM: Pre-2006	600 kW	Caterpillar	SR4	6FA06166
		890 hp		3412	81Z09924
HA15	Emergency Generator DOM: Pre-2006	400 kW	Magna One Generator	502FDR8056AB-L000W	KK-95206-3
		536 hp	Detroit Diesel Engine	71237305	12VA069124
HA16	Emergency Generator DOM: Pre-2006	400 kW	Magna One Generator	502FDR8056AB-L000W	KK-95206-1
		536 hp	Detroit Diesel Engine	71237305	12VA069593
HA17	Emergency Generator DOM: Pre-2006	400 kW	Magna One Generator	502FDR8056AB-L000W	KK-95206-2
		536 hp	Detroit Diesel Engine	71237305	12VA066655
HA18	Emergency Generator DOM: 1996	800 kW	Caterpillar	SR-4B	7AJ00864
		1,180 hp		3412	2WJ00740
HA26	Cooling Tower, 2-Cells	4,200 gpm	Evapco	USS 244-3O18	17-830216
HA27	Cooling Tower, 2-Cells	4,200 gpm	Evapco	USS 244-3O18	17-830217
HA28	Cooling Tower, 2-Cells	4,200 gpm	Evapco	USS 244-3O18	17-830218

2. Emission Limitations

a. The permittee shall limit the actual emissions from each emission unit to the PTE listed in Table III-A-2. *[AQR 12.5.2.3; NSR ATC, Modification 10, Revision 0 (12/15/2008); NSR ATC, Modification 12, Revision 1 (08/20/2009); Title V 70 OP (03/28/2016); and Title V 70 OP (12/03/2018)]*

Table III-A-2: PTE (tons per year) – Harrah's Las Vegas

EU	Condition[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
HA06	8,760 hr/yr	0.15	0.15	0.22	0.73	0.01	0.11	0.04
HA07	8,760 hr/yr	0.30	0.30	1.44	1.46	0.02	0.21	0.07
HA08	8,760 hr/yr	0.27	0.27	0.54	1.36	0.02	0.2	0.07
HA09	8,760 hr/yr	0.27	0.27	0.54	1.36	0.02	0.2	0.07
HA10	8,760 hr/yr	0.27	0.27	0.54	1.36	0.02	0.2	0.07
HA11	8,760 hr/yr	0.16	0.16	0.77	0.78	0.01	0.11	0.04
HA12	500 hr/yr	0.20	0.20	2.87	0.62	0.01	0.23	0.01
HA13	500 hr/yr	0.22	0.22	7.39	1.70	0.01	0.22	0.01
HA14	500 hr/yr	0.16	0.16	5.34	1.23	0.01	0.16	0.01
HA15	500 hr/yr	0.30	0.30	4.16	0.90	0.01	0.34	0.01
HA16	500 hr/yr	0.30	0.30	4.16	0.90	0.01	0.34	0.01
HA17	500 hr/yr	0.30	0.30	4.16	0.90	0.01	0.34	0.01
HA18	500 hr/yr	0.21	0.21	7.08	1.62	0.01	0.21	0.01
HA26	8,760 hr/yr	0.22	0.22	0	0	0	0	0
HA27	8,760 hr/yr	0.22	0.22	0	0	0	0	0
HA28	8,760 hr/yr	0.22	0.22	0	0	0	0	0

[1]The quantities in this column are not intended as enforceable permit limits unless stated otherwise in this permit.

b. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant in excess of an average of 20% opacity for a period of more than six consecutive minutes. *[AQR 26.1]*

3. Production Limitations

a. The permittee shall limit the operation of each of the diesel-fired emergency generators and the fire pump for testing and maintenance purposes to 100 hours per year. The permittee may operate each of the emergency generators and the fire pump up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EUs: HA12 through HA18). *[40 CFR Part 63.6640(f)(i)(ii)]*

4. Control Requirements

Boilers/Water Heaters

a. The permittee shall combust only natural gas in all boilers/heaters. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

b. The permittee shall operate and maintain all boilers/heaters in accordance with the manufacturer's operations and maintenance (O&M) manual for emissions-related components and good combustion practices. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

c. The permittee shall operate and maintain the 4.5 MMBtu/hr boiler (EU: HA06) with burners that have a manufacturer's maximum emission concentration of 9 ppm NOx, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

d. The permittee shall operate and maintain the 4.5 MMBtu/hr boiler (EU: HA06) with burners that have a manufacturer's maximum emission concentration of 50 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

e. The permittee shall operate and maintain the 9.0 MMBtu/hr boiler (EU: HA07) with burners that have a manufacturer's maximum emission concentration of 30 ppm NOx, corrected to 3% oxygen, and flue gas recirculation control devices (FGR). *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

f. The permittee shall operate and maintain the 9.0 MMBtu/hr boiler (EU: HA07) with burners that have a manufacturer's maximum emission concentration of 50 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

g. The permittee shall operate and maintain the 8.369 MMBtu/hr boilers (EUs: HA08 through HA10) with burners that have a manufacturer's maximum emission concentration of 12 ppm NOx, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

h. The permittee shall operate and maintain the 8.369 MMBtu/hr boilers (EUs: HA08 through HA10) with burners that have a manufacturer's maximum emission concentration of 50 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

i. The permittee shall operate and maintain the 4.80 MMBtu/hr boiler (EU: HA11) with burners that have a manufacturer's maximum emission concentration of 30 ppm NOx, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

j. The permittee shall operate and maintain the 4.80 MMBtu/hr boiler (EU: HA11) with burners that have a manufacturer's maximum emission concentration of 50 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

Diesel Generators/Fire Pumps

k. The permittee shall operate and maintain all diesel generators and fire pumps in accordance with the manufacturer's O&M manual for emissions-related components. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

l. The permittee shall operate the emergency fire pump with a turbocharger (EU: HA12). *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

m. The permittee shall operate each generator with turbochargers (EUs: HA13 through HA18). *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

Cooling Towers

n. The permittee shall operate and maintain all cooling towers in accordance with the manufacturer's O&M manual for emissions-related components. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

o. No chromium-containing compounds shall be used for water treatment. *[40 CFR Part 63.402]*

p. The permittee shall operate the cooling towers with drift eliminators that have a manufacturer's maximum drift rate of 0.001% (EUs: HA26 through HA28). *[Title V 70 OP (12/03/2018)]*

q. The permittee shall limit the total dissolved solids (TDS) content of each cooling tower's circulation water to 5,000 ppm (EUs: HA26 through HA28). *[Title V 70 OP (12/03/2018)]*

Other

r. The permittee shall not cause, suffer, or allow any source to discharge air contaminants (or other materials) in quantities that will cause a nuisance, including excessive odors. *[AQR 40 & AQR 43]*

5. Monitoring

Boilers/Water Heaters

a. The permittee shall perform a burner efficiency test once each calendar year (EUs: HA06 through HA11). *[AQR 12.5.2.6(d)]*

b. The permittee shall conduct burner efficiency tests in accordance with the manufacturer's O&M manual and good combustion practices. Alternative methods may be used upon Control Officer approval (EUs: HA06 through HA11). *[AQR 12.5.2.6(d)]*

c. The permittee shall not have to perform a burner efficiency test if the actual hours of operation are 0. To exercise this option, the permittee must install an hour meter and begin keeping written records before the start of the calendar year (EUs: HA06 through HA11). *[AQR 12.5.2.6(d)]*

d. The permittee may replace one contemporaneously-required burner efficiency test with a performance test that has acceptable results (EUs: HA06 through HA11). *[AQR 12.5.2.6(d)*

Diesel Generators/Fire Pumps

e. The permittee shall monitor operating hours for each applicable diesel engine utilizing nonresettable hour meters when operated for testing, maintenance, or during emergencies. (EUs: HA12 through HA18). *[AQR 12.5.2.6(d)]*

Visible Emissions

f. The responsible official shall sign and adhere to the *Visible Emissions Check Guidebook* and keep a copy of the signed guide on-site at all times. *[AQR 12.5.2.6(d)]*

g. The permittee shall conduct a visual emissions check at least quarterly on each diesel-fired emergency generator and fire pump while in operation. *[AQR 12.5.2.6(d)]*

h. If no plume appears to exceed the opacity standard during the visible emissions check, the date, location, and results shall be recorded, along with the viewer's name. *[AQR 12.5.2.6(d)]*

i. If a plume appears to exceed the opacity standard, the permittee shall do one of the following: *[AQR 12.5.2.6(d)]*

   i. Immediately correct the perceived exceedance, then record the first and last name of the person who performed the emissions check, the date the check was performed, the unit(s) observed, and the results of the observation; or

   ii. Call a certified VEE reader to perform an EPA Method 9 evaluation.

      a. For sources required to have a certified reader on-site, the reader shall start Method 9 observations within 15 minutes of the initial observation. For all other sources, the reader shall start Method 9 observations within 30 minutes of the initial observation.

      b. If no opacity exceedance is observed, the certified VEE reader shall record the first and last name of the person who performed the VEE, the date the VEE was performed, the unit(s) evaluated, and the results. A Method 9 VEE form shall be completed for each emission unit that was initially perceived to have exceeded the opacity limit, and the record shall also indicate:

         (1) The cause of the perceived exceedance;

         (2) The color of the emissions; and

         (3) Whether the emissions were light or heavy.

      c. If an opacity exceedance is observed, the certified VEE reader shall take immediate action to correct the exceedance. The reader shall then record the first and last name of the person performing the VEE, the date the VEE was performed, the unit(s) evaluated, and the results. A Method 9 VEE form shall be completed for each reading identified, and the record shall also indicate:

         (1) The cause of the exceedance;

         (2) The color of the emissions;

         (3) Whether the emissions were light or heavy;

         (4) The duration of the emissions; and

         (5) The corrective actions taken to resolve the exceedance.

j. Any scenario of visible emissions noncompliance can and may lead to enforcement action. *[AQR 12.5.2.6(d)]*

Cooling Towers

k. The permittee shall monitor the TDS in the cooling tower circulation water monthly. The permittee shall use a conductivity meter or an equivalent method approved in advance by the Control Officer to determine TDS. *[AQR 12.5.2.6(d)]*

6. Testing

No performance testing requirements have been identified. *[AQR 12.5.2.8(a)]*

7. Recordkeeping

a. The permittee shall maintain records on site that include, at minimum, the following: *[AQR 12.5.2.6(d)]*

   i. Dates and times when visible emissions checks and observations are made, and the corrective steps taken to bring opacity into compliance;

   ii. Monthly TDS content of cooling tower circulation water;

   iii. Log book of all inspections, maintenance, and repairs, as specified in this document;

   iv. Records of burner efficiency, as specified in this permit; and

   v. Records of location changes for nonroad engines, if applicable.

b. The permittee shall maintain records on site and report the following semiannually: *[AQR 12.5.2.6(d)]*

   i. Date and duration of operation of emergency generators and the fire pump for testing, maintenance, and nonemergency use (EUs: HA12 through HA18); and

   ii. Date and duration of operation of emergency generators and the fire pump for emergency use, including documentation justifying use during the emergency (EUs: HA12 through HA18).

c. The permittee shall include, for all inspections, logs, visible emission checks, and tests required under monitoring, recordkeeping, and reporting sections, at least the date and time, the name of the person performing the action, the results or findings, and the type of corrective action taken (if required). *[AQR 12.5.2.6(d)]*

B. FLAMINGO LAS VEGAS

1. Emission Units

a. The stationary source activities at Flamingo Las Vegas, covered by this Part 70 OP, consist of the emission units and associated appurtenances summarized in Table III-B-1. *[AQR 12.5.2.3; NSR ATC, Modification 7, Revision 0 (01/29/2008); NSR ATC, Modification 10, Revision 0 (12/15/2008); NSR ATC, Modification 12, Revision 1 (08/20/2009); NSR ATC (02/23/11); and Title V OP (05/29/2013), (03/28/2016), and (12/03/2018)]*

Table III-B-1: Summary of EUs – Flamingo Las Vegas

EU	Description	Rating	Make	Model No.	Serial No.
FL01	Natural Gas Boiler	14.343 MMBtu/hr	Johnston	8786	9180-01
FL02	Natural Gas Boiler	14.645 MMBtu/hr	Kewanee	H3S-350-G	10016

EU	Description	Rating	Make	Model No.	Serial No.
FL03	Natural Gas Boiler	14.645 MMBtu/hr	Kewanee	H3S-350-G	10017
FL04	Natural Gas Boiler	14.645 MMBtu/hr	Kewanee	H3S-350-G	10476
FL05	Natural Gas Boiler	8.165 MMBtu/hr	Cleaver Brooks	CBI 700-200-150	0L104650
FL06	Emergency Fire Pump DOM: Pre-2006	313 kW	Fairbanks Morse Pump	5922	K3P1017265
		420 hp	Caterpillar Engine	3406	6TB02994
FL09	Emergency Generator DOM: 1999	750 kW	Caterpillar	SR4B	6EJ01215
		1,109 hp		3412	2WJ02515
FL10	Emergency Generator DOM: 1999	750 kW	Caterpillar	SR4B	6EJ01238
		1,109 hp		3412	2WJ02570
FL11	Emergency Generator DOM: Pre-2006	475 kW	Caterpillar	SR4	6EA01398
		724 hp		3412	81Z08892
FL26	Emergency Generator DOM: 2010	600 kW	Caterpillar	LC7	G7A03394
		923 hp		C18	EST01182
FL28	Cooling Tower, 4-cells	9,600 gpm	Marley	NC8411TAN4BGF	10050562-(A1-A4)
FL29	Cooling Tower, 2-Cells	3,800 gpm	Evapco	USS 244-3N18	17-833834
FL30	Cooling Tower, 2-Cells	3,800 gpm	Evapco	USS 244-3N18	17-833835
FL31	Cooling Tower, 2-Cells	3,800 gpm	Evapco	USS 244-3N18	17-833836

2. Emission Limitations

a. The permittee shall limit the actual emissions from each emission unit to the PTE listed in Table III-B-2. *[NSR ATC, Modification 7, Revision 0 (01/29/2008); NSR ATC, Modification 10, Revision 0 (12/15/2008); NSR ATC, Modification 12, Revision 1 (08/20/2009); NSR ATC (02/23/11); and Title V OP (05/29/2013), (03/28/2016), and (12/03/2018)]*

Table III-B-2: PTE (tons per year) – Flamingo Las Vegas

EU	Condition[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
FL01	8,760 hr/yr	0.47	0.47	2.22	4.43	0.04	0.34	0.12
FL02	8,760 hr/yr	0.48	0.48	3.13	2.38	0.04	0.35	0.12
FL03	8,760 hr/yr	0.48	0.48	3.13	2.38	0.04	0.35	0.12
FL04	8,760 hr/yr	0.48	0.48	3.13	2.38	0.04	0.35	0.12
FL05	8,760 hr/yr	0.27	0.27	1.27	1.46	0.02	0.19	0.07
FL06	500 hr/yr	0.23	0.23	3.26	0.70	0.01	0.27	0.01
FL09	500 hr/yr	0.20	0.20	6.66	1.53	0.01	0.20	0.01
FL10	500 hr/yr	0.20	0.20	6.66	1.53	0.01	0.20	0.01
FL11	500 hr/yr	0.13	0.13	4.35	1.00	0.01	0.13	0.01
FL26	500 hr/yr	0.03	0.03	3.13	0.44	0.00	0.04	0.01
FL28	8,760 hr/yr	2.47	2.47	0.00	0.00	0.00	0.00	0.00

EU	Condition[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
FL29	8,760 hr/yr	0.20	0.20	0.00	0.00	0.00	0.00	0.00
FL30	8,760 hr/yr	0.20	0.20	0.00	0.00	0.00	0.00	0.00
FL31	8,760 hr/yr	0.20	0.20	0.00	0.00	0.00	0.00	0.00

[1]The quantities in this column are not intended as enforceable permit limits unless stated otherwise in this permit.

b. The permittee shall not allow actual emissions from the individual emission units to exceed the emission rates and emission concentrations listed in Table III-B-3. *[AQR 12.5.2.3 and NSR ATC, Modification 7, Revision 0 (01/29/2008)]*

Table III-B-3: Emissions – Flamingo Las Vegas

EU	Rating	NO_x/CO (ppm)[1]	NO_x (lbs/hr)	CO (lbs/hr)
FL01	14.343 MMBtu/hr	NO_x 29/CO 95	0.51	1.01
FL02	14.645 MMBtu/hr	NO_x 40/CO 50	0.71	0.54
FL03	14.645 MMBtu/hr	NO_x 40/CO 50	0.71	0.54
FL04	14.645 MMBtu/hr	NO_x 40/CO 50	0.71	0.54

[1]Corrected to 3% oxygen.

c. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant in excess of an average of 20% opacity for a period of more than six consecutive minutes. *[AQR 26.1]*

3. Production Limitations

a. The permittee shall limit the operation of each of the diesel-fired emergency generators and the fire pump for testing and maintenance purposes to 100 hours per year. The permittee may operate each of the emergency generators and the fire pump up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EUs: FL06 and FL09 through FL11). *[40 CFR Part 63.6640(f)(i)(ii)]*

b. The permittee shall limit the operation of the diesel-fired emergency generator for testing and maintenance purposes to 100 hours per year. The permittee may operate the emergency generator up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EU: FL26). *[40 CFR Part 60.4211(f)]*

4. Control Requirements

Boilers/Water Heaters

a. The permittee shall combust only natural gas in all boilers/heaters. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

b. The permittee shall operate and maintain all boilers/heaters in accordance with the manufacturer's O&M manual for emissions-related components and good combustion practices. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

c. The permittee shall operate and maintain the 14.343 MMBtu/hr boiler (EU: FL01) with burners that have a manufacturer's maximum emission concentration of 29 ppm NO_x, corrected to 3% oxygen, and FGR control devices. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

d. The permittee shall operate and maintain the 14.343 MMBtu/hr boiler (EU: FL01) with burners that have a manufacturer's maximum emission concentration of 95 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

e. The permittee shall operate and maintain the three 14.645 MMBtu/hr boilers (EUs: FL02 through FL04) with burners that have a manufacturer's maximum emission concentration of 40 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 7, Revision 0 (01/29/2008)]*

f. The permittee shall operate and maintain the three 14.645 MMBtu/hr boilers (EUs: FL02 through FL04) with burners that have a manufacturer's maximum emission concentration of 50 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 7, Revision 0 (01/29/2008)]*

g. The permittee shall operate and maintain the 8.165 MMBtu/hr boiler (EU: FL05) with burners that have a manufacturer's maximum emission concentration of 29 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

h. The permittee shall operate and maintain the 8.165 MMBtu/hr boiler (EU: FL05) with burners that have a manufacturer's maximum emission concentration of 55 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

Diesel Generators/Fire Pumps

i. The permittee shall operate and maintain all diesel generators and fire pumps in accordance with the manufacturer's O&M manual for emissions-related components. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

j. The permittee shall operate each of the diesel engines with turbochargers (EUs: FL06, FL09 through FL11, and FL26). *[NSR ATC, Modification 10, Revision 0 (12/15/2008) and NSR ATC (02/23/2011)]*

k. The permittee shall ensure that the diesel engine is in compliance with 40 CFR Part 60, Subpart IIII, by meeting of all of the following (EU: FL26): *[40 CFR Part 60.4206]*

    i. Operation of the engine according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer; and

    ii. Installation and configuration of the engine according to the manufacturer's specifications.

Cooling Towers

l. The permittee shall operate and maintain all cooling towers in accordance with the manufacturer's O&M manual for emissions-related components. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

m. No chromium-containing compounds shall be used for water treatment. *[40 CFR Part 63.402]*

n. The permittee shall operate the cooling tower with drift eliminators with a manufacturer's maximum drift rate of 0.005% (EUs: FL28). *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

o. The permittee shall operate the cooling towers with drift eliminators that have a manufacturer's maximum drift rate of 0.001% (EUs: FL29 through FL31). *[Title V OP (12/03/2018)]*

p. The permittee shall limit the TDS content of each cooling tower's circulation water to 5,000 ppm (EUs: FL28 through FL31). *[Title V OP (12/03/2018)]*

Other

q. The permittee shall not cause, suffer, or allow any source to discharge air contaminants (or other materials) in quantities that will cause a nuisance, including excessive odors. *[AQR 40 & AQR 43]*

5. Monitoring

Boilers/Water Heaters

a. The permittee shall install and utilize nonresettable fuel meters such that the daily consumption of natural gas can be established for each applicable boiler (EUs: FL01 through FL04). *[AQR 12.5.2.6(d) and 40 CFR Part 60.48c(g)(1)]*

b. The permittee, when operating a boiler with a maximum heat input rating equal to or greater than 4.0 MMBtu/hr but less than 10.0 MMBtu/hr, shall perform a burner efficiency test once each calendar year (EU: FL05). *[AQR 12.5.2.6(d)]*

c. The permittee, when operating a boiler with a maximum heat input rating equal to or greater than 10.0 MMBtu/hr, shall perform a burner efficiency test twice each calendar year, at least five months apart, but no more than seven (EUs: FL01 through FL04). *[AQR 12.5.2.6(d)]*

d. The permittee shall conduct burner efficiency tests in accordance with the manufacturer's O&M manual and good combustion practices. Alternative methods may be used upon Control Officer approval (EUs: FL01 through FL05). *[AQR 12.5.2.6(d)]*

e. The permittee may choose not to perform a burner efficiency test on a boiler during the calendar year if the documented actual hours of operation of that boiler, with a maximum heat input rating equal to or greater than 4.0 MMBtu/hr but less than 10.0 MMBtu/hr, are zero during a calendar year. To exercise this option, the permittee must install an hour meter and begin keeping written records before the start of the calendar year (EUs: FL05). *[AQR 12.5.2.6(d)]*

f. The permittee may perform a burner efficiency test once each calendar year if the actual hours of operation are less than 50. To exercise this option, the permittee must install an hour meter and begin keeping written records before the start of the calendar year (EUs: FL01 through FL04). *[AQR 12.5.2.6(d)]*

g. The permittee may replace one contemporaneously-required burner efficiency test with a performance test that has acceptable results (EUs: FL01 through FL05). *[AQR 12.5.2.6(d)]*

Diesel Generators/Fire Pumps

h. The permittee shall monitor operating hours for each applicable diesel engine utilizing nonresettable hour meters (EUs: FL06, FL09 through FL11, and FL26). *[AQR 12.5.2.6(d)]*

Visible Emissions

i. The responsible official shall sign and adhere to the *Visible Emissions Check Guidebook* and keep a copy of the signed guide on-site at all times. *[AQR 12.5.2.6(d)]*

j. The permittee shall conduct a visual emissions check at least quarterly on each diesel-fired emergency generator and fire pump while in operation. *[AQR 12.5.2.6(d)]*

k. If no plume appears to exceed the opacity standard during the visible emissions check, the date, location, and results shall be recorded, along with the viewer's name. *[AQR 12.5.2.6(d)]*

l. If a plume appears to exceed the opacity standard, the permittee shall do one of the following: *[AQR 12.5.2.6(d)]*

  i. Immediately correct the perceived exceedance, then record the first and last name of the person who performed the emissions check, the date the check was performed, the unit(s) observed, and the results of the observation; or

  ii. Call a certified VEE reader to perform an EPA Method 9 evaluation.

    a. For sources required to have a certified reader on-site, the reader shall start Method 9 observations within 15 minutes of the initial observation. For all other sources, the reader shall start Method 9 observations within 30 minutes of the initial observation.

    b. If no opacity exceedance is observed, the certified VEE reader shall record the first and last name of the person who performed the VEE, the date the VEE was performed, the unit(s) evaluated, and the results. A Method 9 VEE form shall be completed for each emission unit that was initially perceived to have exceeded the opacity limit, and the record shall also indicate:

      (1) The cause of the perceived exceedance;

      (2) The color of the emissions; and

      (3) Whether the emissions were light or heavy.

c. If an opacity exceedance is observed, the certified VEE reader shall take immediate action to correct the exceedance. The reader shall then record the first and last name of the person performing the VEE, the date the VEE was performed, the unit(s) evaluated, and the results. A Method 9 VEE form shall be completed for each reading identified, and the record shall also indicate:

(1) The cause of the exceedance;

(2) The color of the emissions;

(3) Whether the emissions were light or heavy;

(4) The duration of the emissions; and

(5) The corrective actions taken to resolve the exceedance.

m. Any scenario of visible emissions noncompliance can and may lead to enforcement action. *[AQR 12.5.2.6(d)]*

Cooling Towers

n. The permittee shall continue to monitor the TDS in the cooling tower circulation water monthly. The permittee shall use a conductivity meter or an equivalent method approved in advance by the Control Officer to determine TDS. *[AQR 12.5.2.6(d)]*

6. Testing

Boiler Performance Tests

a. Performance testing shall be the instrument for determining compliance with emission limitations set forth in this permit for all boilers that have a heat input rating equal to or greater than 10.0 MMBtu/hr (EUs: FL01 through FL04). *[AQR 12.5.2.8(a) and DAQ's "Guidelines for Source Testing"]*

b. The permittee shall conduct performance tests on each boiler (EUs: FL01, FL02, FL03, and FL04) every five years, and no later than 90 days after the anniversary date of the last performance test. *[AQR 12.5.2.8(a) and DAQ's "Guidelines for Source Testing"]*

Table III-B-4: Performance Testing Protocol Requirements

Test Point	Pollutant	Method
Boiler Exhaust Outlet Stack	NO_x	EPA Method 7E
Boiler Exhaust Outlet Stack	CO	EPA Method 10 analyzer
Stack Gas Parameters	—	EPA Methods 1, 2, 3A, and 4

7. Recordkeeping

a. The permittee shall maintain records on site that include, at minimum, the following: *[AQR 12.5.2.6(d)]*

i. Dates and times when visible emissions checks and observations are made, and the corrective steps taken to bring opacity into compliance;

ii. Monthly TDS content of cooling tower circulation water;

iii. Log book of all inspections, maintenance, and repairs, as specified in this document;

iv. Records of burner efficiency testing, as specified in this OP;

v. Results of performance testing; and

vi. Records of location changes for nonroad engines, if applicable.

b. The permittee shall maintain on site and report the following semiannually: *[AQR 12.5.2.6(d)]*

i. Monthly amount of natural gas consumed (in MMBtu, scf, or therms) for each boiler (EUs: FL01 through FL04); *[40 CFR Part 60.48c(g)(1)]*

ii. Date and duration of operation of the emergency generators and the fire pump for testing, maintenance, and nonemergency use (EUs: FL06, FL09 through FL11, and FL26); and

iii. Date and duration of operation of the generators and fire pump for emergency use, including documentation justifying use during the emergency (EUs: FL06 through FL11 and FL26);

c. permittee shall include, for all inspections, logs, visible emission checks, and testing required under monitoring, recordkeeping, and reporting sections, at least the date and time, the name of the person performing the action, the results or findings, and the type of corrective action taken (if required). *[AQR 12.5.2.6(d)]*

C. BALLY'S LAS VEGAS

1. Emission Units

a. The stationary source activities at Bally's Las Vegas, covered by this Part 70 OP, consist of the emission units and associated appurtenances summarized in Table III-C-1. *[AQR 12.5.2.3; NSR ATC, Modification 10, Revision 0 (12/15/2008); NSR ATC, Modification 12, Revision 1 (08/20/2009); Title V OP (03/28/2016), (05/05/2017), and (12/19/2019); and Application for Renewal of Part 70 OP (09/25/2020)]*

Table III-C-1: Summary of EUs – Bally's Las Vegas

EU	Description	Rating	Make	Model No.	Serial No.
BA01	Natural Gas Boiler	16.8 MMBtu/hr	Kewanee	H3S-750-G02	NB-24935
BA02	Natural Gas Boiler	16.8 MMBtu/hr	Kewanee	H3S-750-G02	NB-25232
BA03	Natural Gas Boiler	25.106 MMBtu/hr	Kewanee	H3S-750-G02	NB-24875

EU	Description	Rating	Make	Model No.	Serial No.
BA04	Emergency Generator (#1) DOM: Pre-2006	1,000 kW	Magna One	682FDR8080AB-P667W	LD95982-1
		1,340 hp	Detroit Diesel	9163-7305	16E0006591
BA05	Emergency Generator (#2) DOM: Pre-2006	1,000 kW	Magna One	682FDR8080AB-P667W	LD-95982-2
		1,340 hp	Detroit Diesel	9163-7305	16E0006592
BA06	Emergency Generator DOM: Pre-2006	500 kW	Magna One	500SR9E	66111
		670 hp	Detroit Diesel	7163-7305	16VA7496
BA07	Emergency Generator DOM: Pre-2006	155 kW	Magna One	440FDR8024GG-H000W	LD-94032
		200 hp	Detroit Diesel		
BA11	Emergency Generator (#3) DOM: Pre-2006	1,000 kW	Detroit	1000 DS	600214
		1,340 hp		L18107	24VA001710
BA12	Emergency Generator (#4) DOM: Pre-2006	1,000 kW	Detroit	1000 DS	600215
		1,340 hp		L18127	24VA001728
BA17	Emergency Fire Pump DOM: 06/2011	526 hp	Clarke Fire Pump	JX6H-UFADK0-D	RG6135L023246
			John Deere Engine	6135HFC48A	
BA18	Emergency Fire Pump DOM: 04/2011	526 hp	Clarke Fire Pump	JX6H-UFADK0-D	RG6135L022100
			John Deere Engine	6135HFC48A	
BA19	Cooling tower – 3 cells	18,000 GPM	Evapco	USS 314-4O72	16-804451
BA20	Cooling tower – 3 cells	18,000 GPM	Evapco	USS314-4O72	16-804450

2. Emission Limitations

a. The permittee shall limit the actual emissions from each emission unit to the PTE listed in Table III-C-2. *[NSR ATC, Modification 10, Revision 0 (12/15/2008); NSR ATC, Modification 12, Revision 1 (08/20/2009); Title V OP (03/28/2016), (05/05/2017), and (12/19/2019); Application for Renewal of Part 70 OP (09/25/2020)]*

Table III-C-2: PTE (tons per year) – Bally's Las Vegas

EU	Condition[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
BA01	8,760 hr/yr	0.55	0.55	2.24	1.25	0.04	0.40	0.14
BA02	8,760 hr/yr	0.55	0.55	2.24	1.25	0.04	0.40	0.14
BA03	8,760 hr/yr	0.82	0.82	3.34	1.87	0.07	0.59	0.21

EU	Condition[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
BA04	500 hr/yr	0.24	0.24	8.04	1.84	0.01	0.24	0.01
BA05	500 hr/yr	0.24	0.24	8.04	1.84	0.01	0.24	0.01
BA06	500 hr/yr	0.12	0.12	4.02	0.92	0.01	0.12	0.01
BA07	500 hr/yr	0.11	0.11	1.55	0.34	0.01	0.13	0.00
BA11	500 hr/yr	0.24	0.24	8.04	1.84	0.01	0.24	0.01
BA12	500 hr/yr	0.24	0.24	8.04	1.84	0.01	0.24	0.01
BA17	500 hr/yr	0.01	0.01	0.76	0.12	0.01	0.03	0.01
BA18	500 hr/yr	0.01	0.01	0.76	0.12	0.01	0.03	0.01
BA19	8,760 hr/yr	0.93	0.93	0.00	0.00	0.00	0.00	0.00
BA20	8,760 hr/yr	0.93	0.93	0.00	0.00	0.00	0.00	0.00

[1]The quantities in this column are not intended as enforceable permit limits unless stated otherwise in this permit.

b. The permittee shall not allow actual emissions from the individual emission units to exceed the emission rates and emission concentrations listed in Table III-C-3. *[AQR 12.5.2.3]*

Table III-C-3: Emissions – Bally's Las Vegas

EU	Rating	NO_x/CO (ppm)[1]	NO_x (lbs/hr)	CO (lbs/hr)
BA01	16.8 MMBtu/hr	NO_x 25/CO 23	0.51	0.29
BA02	16.8 MMBtu/hr	NO_x 25/CO 23	0.51	0.29
BA03	25.106 MMBtu/hr	NO_x 25/CO 23	0.77	0.43

[1]Corrected to 3% oxygen.

c. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant in excess of an average of 20% opacity for a period of more than six consecutive minutes. *[AQR 26.1]*

3. Production Limitations

a. The permittee shall limit the operation of each of the diesel-fired emergency generators for testing and maintenance purposes to 100 hours per year. The permittee may operate each of the emergency generators up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EUs: BA04 through BA07, BA11, and BA12). *[40 CFR Part 63.6640(f)(i)(ii)]*

b. The permittee shall limit the operation of each of the fire pumps for testing and maintenance purposes to 100 hours per year. The permittee may operate each fire pumps up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance (EUs: BA17 and BA18). *[40 CFR Part 60.4211(f)]*

4. Control Requirements

Boilers/Water Heaters

a. The permittee shall combust only natural gas in all boilers/heaters. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

b. The permittee shall operate and maintain all boilers/heaters in accordance with the manufacturer's O&M manual for emissions-related components and good combustion practices. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

c. The permittee shall operate and maintain each of the 16.8 MMBtu/hr boilers (EUs: BA01 and BA02) with burners that have a manufacturer's maximum emission concentration of 25 ppm NO_x, corrected to 3% oxygen, and FGR control devices. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

d. The permittee shall operate and maintain each of the 16.8 MMBtu/hr boilers (EUs: BA01 and BA02) with burners that have a manufacturer's maximum emission concentration of 23 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

e. The permittee shall operate and maintain the 25.106 MMBtu/hr boiler (EU: BA03) with burners that have a manufacturer's maximum emission concentration of 25 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

f. The permittee shall operate and maintain the 25.106 MMBtu/hr boiler (EU: BA03) with burners that have a manufacturer's maximum emission concentration of 23 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

Diesel Generators/Fire Pumps

g. The permittee shall operate and maintain all diesel generators and fire pumps in accordance with the manufacturer's O&M manual for emissions-related components. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

h. The permittee shall operate each of the diesel engines with turbochargers (EUs: BA04 through BA07, BA11, and BA12). *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

i. The permittee shall operate each of the diesel fire pumps with turbochargers and aftercoolers (EUs: BA17 and BA18). *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

j. The permittee shall ensure that the diesel engines are in compliance with 40 CFR Part 60, Subpart IIII, by meeting of all of the following (EUs: BA17 and BA18): *[40 CFR Part 60.4211]*

   i. operation of the engine according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer; and

   ii. installation and configuration of the engine according to the manufacturer's specifications.

Cooling Towers

k. The permittee shall operate and maintain all cooling towers in accordance with the manufacturer's O&M manual for emissions-related components. *[Title V OP (05/05/2017)]*

l. No chromium-containing compounds shall be used for water treatment. *[40 CFR Part 63.402]*

m. The permittee shall operate the cooling tower with drift eliminators with a manufacturer's maximum drift rate of 0.001% (EU: BA19). *[Title V OP (05/05/2017)]*

n. The permittee shall operate the cooling tower with drift eliminators that have a manufacturer's maximum drift rate of 0.001% (EU: BA20). *[Title V OP (12/19/2019)]*

o. The permittee shall limit the TDS content of each cooling tower's circulation water to 5,000 ppm (EU: BA19). *[Title V OP (12/19/2019)]*

Other

p. The permittee shall not cause, suffer, or allow any source to discharge air contaminants (or other materials) in quantities that will cause a nuisance, including excessive odors. *[AQR 40 & AQR 43]*

5. Monitoring

Boilers/Water Heaters

a. The permittee shall install and utilize nonresettable fuel meters such that the daily consumption of natural gas can be established for each applicable boiler (EUs: BA01 through BA03). *[AQR 12.5.2.6(d) and 40 CFR Part 60.48c(g)(1)]*

b. The permittee shall perform a burner efficiency test twice each calendar year, at least five months apart but no more than seven (EUs: BA01 through BA03). *[AQR 12.5.2.6(d)]*

c. The permittee shall conduct burner efficiency tests in accordance with the manufacturer's O&M manual and good combustion practices. Alternative methods may be used upon Control Officer approval (EUs: BA01 through BA03). *[AQR 12.5.2.6(d)]*

d. The permittee may perform a burner efficiency test once each calendar year if the actual hours of operation are less than 50. To exercise this option, the permittee must install an hour meter and begin keeping written records before the start of the calendar year (EUs: BA01 through BA03). *[AQR 12.5.2.6(d)]*

e. The permittee may replace one contemporaneously-required burner efficiency test with a performance test that has acceptable results (EUs: BA01 through BA03). *[AQR 12.5.2.6(d)]*

Diesel Generators/Fire Pumps

f. The permittee shall install and utilize nonresettable hour meters such that the daily operating hours can be established for each applicable diesel engine (EUs: BA04 through BA07, BA11, BA12, BA17, and BA18). *[AQR 12.5.2.6(d)]*

Visible Emissions

g. The responsible official shall sign and adhere to the *Visible Emissions Check Guidebook* and keep a copy of the signed guide on-site at all times. *[AQR 12.5.2.6(d)]*

h. The permittee shall conduct a visual emissions check at least quarterly on each diesel-fired emergency generator and fire pump while in operation. *[AQR 12.5.2.6(d)]*

i. If no plume appears to exceed the opacity standard during the visible emissions check, the date, location, and results shall be recorded, along with the viewer's name. *[AQR 12.5.2.6(d)]*

j. If a plume appears to exceed the opacity standard, the permittee shall do one of the following: *[AQR 12.5.2.6(d)]*

    i. Immediately correct the perceived exceedance, then record the first and last name of the person who performed the emissions check, the date the check was performed, the unit(s) observed, and the results of the observation; or

    ii. Call a certified VEE reader to perform an EPA Method 9 evaluation.

        a. For sources required to have a certified reader on-site, the reader shall start Method 9 observations within 15 minutes of the initial observation. For all other sources, the reader shall start Method 9 observations within 30 minutes of the initial observation.

        b. If no opacity exceedance is observed, the certified VEE reader shall record the first and last name of the person who performed the VEE, the date the VEE was performed, the unit(s) evaluated, and the results. A Method 9 VEE form shall be completed for each emission unit that was initially perceived to have exceeded the opacity limit, and the record shall also indicate:

            (1) The cause of the perceived exceedance;

            (2) The color of the emissions; and

            (3) Whether the emissions were light or heavy.

        c. If an opacity exceedance is observed, the certified VEE reader shall take immediate action to correct the exceedance. The reader shall then record the first and last name of the person performing the VEE, the date the VEE was performed, the unit(s) evaluated, and the results. A Method 9 VEE form shall be completed for each reading identified, and the record shall also indicate:

            (1) The cause of the exceedance;

            (2) The color of the emissions;

            (3) Whether the emissions were light or heavy;

(4) The duration of the emissions; and

(5) The corrective actions taken to resolve the exceedance.

k. Any scenario of visible emissions noncompliance can and may lead to enforcement action. *[AQR 12.5.2.6(d)]*

Cooling Towers

l. The permittee shall monitor the TDS in the cooling tower circulation water monthly. The permittee may use a conductivity meter or an equivalent method approved in advance by the Control Officer to determine TDS. *[AQR 12.5.2.6(d)]*

6. Testing

a. Performance testing shall be the instrument for determining compliance with emission limitations set forth in this permit for all boilers that have a heat input rating equal to or greater than 10.0 MMBtu/hr (EUs: BA01, BA02, and BA03). *[AQR 12.5.2.8(a) and DAQ's "Guidelines for Source Testing"]*

b. The permittee shall conduct performance tests on each boiler (EUs: BA01, BA02, and BA03) every five years, and no later than 90 days after the anniversary date of the last performance test. *[AQR 12.5.2.8(a) and DAQ's "Guidelines for Source Testing"]*

Table III-C-4: Performance Testing Protocol Requirements

Test Point	Pollutant	Method
Boiler Exhaust Outlet Stack	NO_x	EPA Method 7E
Boiler Exhaust Outlet Stack	CO	EPA Method 10 analyzer
Stack Gas Parameters	—	EPA Methods 1, 2, 3A, and 4

7. Recordkeeping

a. The permittee shall maintain records on site that include, at minimum, the following: *[AQR 12.5.2.6(d)]*

i. Dates and times when visible emissions checks and observations are made, and the corrective steps taken to bring opacity into compliance;

ii. Monthly TDS content of cooling tower circulation water;

iii. Log book of all inspections, maintenance, and repairs as specified in this document;

iv. Results of performance testing; and

v. Records of location changes for nonroad engines, if applicable.

b. The permittee shall maintain records on site and report the following semiannually: *[AQR 12.5.2.6(d)]*

i. Monthly amount of natural gas consumed (in MMBtu, scf, or therms) for each boiler (EUs: BA01, BA02 and BA03); *[40 CFR Part 60.48c(g)(1)]*

ii. Date and duration of operation of the emergency generators and the fire pump for testing, maintenance, and nonemergency use (EUs: BA04 through BA07, BA11, BA12, BA17, and BA18); and

Date and duration of operation of the generators and fire pumps for emergency use, including documentation justifying use during the emergency (EUs: BA04 through BA07, BA11, BA12, BA17, and BA18).

c. The permittee shall include, for all inspections, logs, visible emission checks, and tests required under monitoring, recordkeeping, and reporting sections, at least the date and time, the name of the person performing the action, the results or findings, and the type of corrective action taken (if required). *[AQR 12.5.2.6(d)]*

D. THE CROMWELL LAS VEGAS

1. Emission Units

a. The stationary source activities at The Cromwell Las Vegas, covered by this Part 70 OP consist of the emission units and associated appurtenances summarized in Table III-D-1. *[AQR 12.5.2.3 and Title V OP (03/28/2016)]*

Table III-D-1: Summary of EUs – The Cromwell Las Vegas

EU	Description	Rating	Make	Model No.	Serial No.
CR01	Natural Gas Boiler	3.0 MMBtu/hr	Lochinvar	FBN3000	G13H00252062
CR02	Natural Gas Boiler	3.0 MMBtu/hr	Lochinvar	FBN3000	G13H00252063
CR03	Natural Gas Boiler	3.0 MMBtu/hr	Lochinvar	FBN3000	G13H00252141
CR04	Natural Gas Boiler	3.0 MMBtu/hr	Lochinvar	FBN3000	G13H00252065
CR05	Natural Gas Boiler	3.0 MMBtu/hr	Lochinvar	FBN3000	G13H00251706
CR06	Natural Gas Boiler	3.0 MMBtu/hr	Lochinvar	FBN3000	G13H00252064
CR07	Diesel Engine Emergency Generator DOM: 2013	1,500 kW	Caterpillar	SR4B-GD	G4W01097
		3,634 hp	Caterpillar	3512C	EBG01274
CR08	Diesel Engine Emergency Generator DOM: 2013	150 kW	Caterpillar	D150-8	CAT00C66ALC600121
		275 hp	Caterpillar	C6.6	E6L00768
CR09	Cooling Tower, 3-cell	5,400 gpm	Evapco	USS-312-936	13-541894

2. Emission Limitations

a. The permittee shall limit the actual emissions from each emission unit to the PTE listed in Table III-D-2. *[Title V OP (03/28/2016) and (12/19/2019)]*

Table III-D-2: PTE (tons per year) – The Cromwell Las Vegas

EU	Condition[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
CR01	8,760 hr/yr	0.10	0.10	0.16	0.49	0.01	0.07	0.02
CR02	8,760 hr/yr	0.10	0.10	0.16	0.49	0.01	0.07	0.02
CR03	8,760 hr/yr	0.10	0.10	0.16	0.49	0.01	0.07	0.02
CR04	8,760 hr/yr	0.10	0.10	0.16	0.49	0.01	0.07	0.02
CR05	8,760 hr/yr	0.10	0.10	0.16	0.49	0.01	0.07	0.02
CR06	8,760 hr/yr	0.10	0.10	0.16	0.49	0.01	0.07	0.02
CR07	500 hr/yr	0.06	0.06	10.18	0.88	0.01	0.22	0.03
CR08	500 hr/yr	0.02	0.02	0.43	0.09	0.01	0.17	0.01
CR09	8,760 hr/yr	0.28	0.28	0.00	0.00	0.00	0.00	0.00

[1]The quantities in this column are not intended as enforceable permit limits unless stated otherwise in this permit.

b. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant in excess of an average of 20% opacity for a period of more than six consecutive minutes. *[AQR 26.1]*

3. Production Limitations

a. The permittee shall limit the operation of each of the diesel-fired emergency generators for testing and maintenance purposes to 100 hours per year. The permittee may operate each emergency generator up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EUs: CR07 and CR08). *[40 CFR Part 60.4211(f)]*

4. Control Requirements

Boilers/Water Heaters

a. The permittee shall combust only natural gas in all boilers/heaters. *[Title V OP (03/28/2016)]*

b. The permittee shall operate and maintain all boilers/heaters in accordance with the manufacturer's O&M manual for emissions-related components and good combustion practices. *[Title V OP (03/28/2016)]*

c. The permittee shall operate and maintain the boilers (EUs: CR01 through CR06) with burners that have a manufacturer's maximum emission concentration of 10 ppm NO_x, corrected to 3% oxygen. *[Title V OP (03/28/2016)]*

d. The permittee shall operate and maintain the boilers (EUs: CR01 through CR06) with burners that have a manufacturer's maximum emission concentration of 50 ppm CO, corrected to 3% oxygen. *[Title V OP (03/28/2016)]*

Diesel Generators

e. The permittee shall operate and maintain all diesel generators in accordance with the manufacturer's O&M manual for emissions-related components. *[Title V OP (03/28/2016)]*

f. The permittee shall operate each of the diesel engines with turbochargers and aftercoolers (EUs: CR07 and CR08). *[Title V OP (03/28/2016)]*

g. The permittee shall ensure that the diesel engines are in compliance with 40 CFR Part 60, Subpart IIII, by meeting of all of the following (EUs: CR07 and CR08): *[40 CFR Part 60.4206]*

   i. operation of the engine according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer; and

   ii. installation and configuration of the engine according to the manufacturer's specifications.

Cooling Towers

h. The permittee shall operate and maintain the cooling tower in accordance with the manufacturer's O&M manual for emissions-related components. *[Title V OP (03/28/2016)]*

i. No chromium-containing compounds shall be used for water treatment. *[40 CFR Part 63.402]*

j. The permittee shall operate the cooling tower with drift eliminators that have a manufacturer's maximum drift rate of 0.001% (EU: CR09). *[Title V OP (03/28/2016)]*

k. The permittee shall limit the TDS content of each cooling tower's circulation water to 5,000 ppm (EU: CR09). *[Title V OP (12/19/2019)]*

Other

l. The permittee shall not cause, suffer, or allow any source to discharge air contaminants (or other materials) in quantities that will cause a nuisance, including excessive odors. *[AQR 40 & AQR 43]*

5. Monitoring

Diesel Generators

a. The permittee shall monitor operating hours for each applicable diesel engine utilizing nonresettable hour meters when operated for testing, maintenance, or during emergencies. (EUs: CR07 and CR08). *[AQR 12.5.2.6(d)]*

Visible Emissions

b. The responsible official shall sign and adhere to the *Visible Emissions Check Guidebook* and keep a copy of the signed guide on-site at all times. *[AQR 12.5.2.6(d)]*

c. The permittee shall conduct a visual emissions check at least quarterly on each diesel-fired emergency generator while in operation. *[AQR 12.5.2.6(d)]*

d. If no plume appears to exceed the opacity standard during the visible emissions check, the date, location, and results shall be recorded, along with the viewer's name. *[AQR 12.5.2.6(d)]*

e. If a plume appears to exceed the opacity standard, the permittee shall do one of the following: *[AQR 12.5.2.6(d)]*

i. Immediately correct the perceived exceedance, then record the first and last name of the person who performed the emissions check, the date the check was performed, the unit(s) observed, and the results of the observation; or

ii. Call a certified VEE reader to perform an EPA Method 9 evaluation.

a. For sources required to have a certified reader on-site, the reader shall start Method 9 observations within 15 minutes of the initial observation. For all other sources, the reader shall start Method 9 observations within 30 minutes of the initial observation.

b. If no opacity exceedance is observed, the certified VEE reader shall record the first and last name of the person who performed the VEE, the date the VEE was performed, the unit(s) evaluated, and the results. A Method 9 VEE form shall be completed for each emission unit that was initially perceived to have exceeded the opacity limit, and the record shall also indicate:

(1) The cause of the perceived exceedance;

(2) The color of the emissions; and

(3) Whether the emissions were light or heavy.

c. If an opacity exceedance is observed, the certified VEE reader shall take immediate action to correct the exceedance. The reader shall then record the first and last name of the person performing the VEE, the date the VEE was performed, the unit(s) evaluated, and the results. A Method 9 VEE form shall be completed for each reading identified, and the record shall also indicate:

(1) The cause of the exceedance;

(2) The color of the emissions;

(3) Whether the emissions were light or heavy;

(4) The duration of the emissions; and

(5) The corrective actions taken to resolve the exceedance.

f. Any scenario of visible emissions noncompliance can and may lead to enforcement action. *[AQR 12.5.2.6(d)]*

Cooling Towers

g. The permittee shall monitor the TDS in the cooling tower circulation water monthly. The permittee may use a conductivity meter or an equivalent method approved in advance by the Control Officer to determine TDS. *[AQR 12.5.2.6(d)]*

6. Testing

No performance testing requirements have been identified. *[AQR 12.5.2.8(a)]*

7. Recordkeeping

a. The permittee shall maintain records on site that include, at minimum, the following: *[AQR 12.5.2.6(d)]*

i. Dates and times when visible emissions checks and observations are made, and the corrective steps taken to bring opacity into compliance;

ii. Monthly TDS content of cooling tower circulation water;

iii. Log book of all inspections, maintenance, and repairs, as specified in this document; and

iv. Records of location changes for nonroad engines, if applicable.

b. The permittee shall maintain records on site and report the following semiannually: *[AQR 12.5.2.6(d)]*

i. The date and duration of operation of emergency generators for testing, maintenance, and nonemergency use (EUs: CR07 and CR08); and

ii. The date and duration of operation of generators for emergency use, including documentation justifying use during the emergency (EUs: CR07 and CR08).

c. The permittee shall include, for all inspections, logs, visible emission checks, and testing required under monitoring, recordkeeping, and reporting sections, at least the date and time, the name of the person performing the action, the results or findings, and the type of corrective action taken (if required). *[AQR 12.5.2.6(d)*

E. CAESARS PALACE

1. Emission Units

a. The stationary source activities at Caesars Palace covered by this Part 70 OP consist of the emission units and associated appurtenances summarized in Table III-E-1. *[AQR 12.5.2.3; NSR ATC, Modification 7, Revision 0 (01/29/2008); NSR ATC, NSR ATC, Modification 10, Revision 0 (12/15/2008); Modification 11, Revision 0 (02/19/2009); NSR ATC, Modification 12, Revision 1 (08/20/2009); Title V OP (03/28/2016); and Application for Renewal of Part 70 OP (09/25/2020)]*

Table III-E-1: Summary of EUs – Caesars Palace

EU	Description	Rating	Make	Model No.	Serial No.
CP01	Natural Gas Boiler	35.40 MMBtu/hr	Hurst	S4-G-800-150	S4000-150-18
CP02	Natural Gas Boiler	35.40 MMBtu/hr	Hurst	S4-G-800-150	S4000-150-19
CP03	Natural Gas Boiler	33.475 MMBtu/hr	Burnham	3P80050GBNM	12524
CP04	Natural Gas Boiler	33.475 MMBtu/hr	Burnham	3P80050GBNM	12164

EU	Description	Rating	Make	Model No.	Serial No.
CP05	Natural Gas Boiler	33.475 MMBtu/hr	Burnham	3P80050GBNM	12238
CP07	Natural Gas Boiler	1.0 MMBtu/hr	Gasmaster	GMI1	221.02
CP13	Emergency Generator DOM: 3/5/1997	2,000 kW	Caterpillar	SR-4B	8DM00558
		2,876 hp		3516	6HN00155
CP14	Emergency Generator DOM: 3/3/1997	2,000 kW	Caterpillar	SR-4B	8DM00557
		2,876 hp		3516	6HN00154
CP15	Emergency Generator DOM: 08/14/1996	1,750 kW	Caterpillar	SR-4B	7GM00534
		2,520 hp		3516	25Z05223
CP16	Emergency Generator DOM: 04/18/1995	1,250 kW	Caterpillar	SR4	4DM00503
		1,818 hp		3512	24Z06413
CP17	Emergency Generator DOM: 12/10/1997	2,000 kW	Caterpillar	SR-4B	8DM00625
		2,876 hp		3516	6HN00199
CP19a	Cooling Tower, Cell 1 of 3	9,000 gpm	Baltimore Aircoil	4469-20-3W	92-4G-6184-P4
CP19b	Cooling Tower, Cell 2 of 3	9,000 gpm	Baltimore Aircoil	4469-20-3W	92-4G-6184-P4
CP19c	Cooling Tower, Cell 3 of 3	9,000 gpm	Baltimore Aircoil	4469-20-3W	92-4G-6184-P4
CP20	Cooling Tower	5,750 gpm	Baltimore Aircoil	3725A3	U040665201MAD
CP21	Cooling Tower	5,750 gpm	Baltimore Aircoil	3725A-4	U040665202MAD
CP22	Cooling Tower	5,750 gpm	Baltimore Aircoil	3725A-5	U040665203MAD
CP24	Natural Gas Boiler	1.5 MMBtu/hr	RBI Futera	FW1500	120644885
CP25	Natural Gas Boiler	1.5 MMBtu/hr	RBI Futera	FW1500	120644886
CP26	Natural Gas Boiler	24.0 MMBtu/hr	Unilux	ZF2500W-1-300/400	A1683
CP27	Natural Gas Boiler	24.0 MMBtu/hr	Unilux	ZF2500W-1-300/400	A1684
CP28	Emergency Generator DOM: 2008	2,000 kW	Caterpillar	SR4B HV	G3X00133
		3,634 hp		3516CDITA	SBJ00672
CP29	Emergency Generator DOM: 2008	2,000 kW	Caterpillar	SR4B HV	G3X00229
		3,634 hp		3516CDITA	SBJ00673
CP30a	Cooling Tower	5,600 gpm	Composite Cooling Solutions	FT-2828-75-P6IL	CT-7

EU	Description	Rating	Make	Model No.	Serial No.
CP30b	Cooling Tower	5,600 gpm	Composite Cooling Solutions	FT-2828-75-P6IL	CT-8
CP32	GDO with an AST and nozzles	1,000-gallon	Fireguard	MWCFG	
CP34	Diesel Fire Pump DOM: Post-2006	525 hp	Clarke Fire Pump	JX6H-UF60	FPVT-C084983-002
			John Deere	6125HF070	RG6125H063341
CP35	Diesel Fire Pump DOM: Post-2006	525 hp	Clarke Fire Pump	JX6H-UF60	FPVT-C084983-001
			John Deere	6125HF070	RG6125H063339
CP37	Natural Gas Pool Heater	1.5 MMBtu/hr	RBI Futera II	FW-1500	101984123
CP41	Natural Gas Water Heater	0.25 MMBtu/hr	A.O. Smith	BTH250A200	1615M000633
CP42	Natural Gas Water Heater	0.25 MMBtu/hr	A.O. Smith	BTH250A100	0826M001486
CP44	Natural Gas Water Heater	0.999 MMBtu/hr	Lochinvar	PBN1002	A15H00273568

2. Emission Limitations

a. The permittee shall limit the actual emissions from each emission unit to the PTE listed in Table III-E-2. *[NSR ATC, Modification 7, Revision 0 (01/29/2008); NSR ATC, NSR ATC, Modification 10, Revision 0 (12/15/2008); Modification 11, Revision 0 (02/19/2009); NSR ATC, Modification 12, Revision 1 (08/20/2009); Title V OP (03/28/2016) and (12/19/2019); and Application for Renewal of Part 70 OP (09/25/2020)]*

Table III-E-2: PTE (tons per year) – Caesars Palace

EU	Condition[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
CP01	8,760 hr/yr	1.16	1.16	5.46	1.15	0.09	0.84	0.29
CP02	8,760 hr/yr	1.16	1.16	5.46	1.15	0.09	0.84	0.29
CP03	8,760 hr/yr	1.10	1.10	5.35	1.08	0.09	0.79	0.28
CP04	8,760 hr/yr	1.10	1.10	5.35	1.08	0.09	0.79	0.28
CP05	8,760 hr/yr	1.10	1.10	5.35	1.08	0.09	0.79	0.28
CP07	8,760 hr/yr	0.03	0.03	0.07	0.25	0.01	0.02	0.01
CP13	500 hr/yr	0.50	0.50	17.26	3.96	0.01	0.51	0.02
CP14	500 hr/yr	0.50	0.50	17.26	3.96	0.01	0.51	0.02
CP15	500 hr/yr	0.44	0.44	15.12	3.47	0.01	0.45	0.02
CP16	500 hr/yr	0.32	0.32	10.91	2.50	0.01	0.32	0.02
CP17	500 hr/yr	0.50	0.50	17.26	3.96	0.01	0.51	0.02
CP19a	8,760 hr/yr	2.32	2.32	0.00	0.00	0.00	0.00	0.00
CP19b	8,760 hr/yr	2.32	2.32	0.00	0.00	0.00	0.00	0.00
CP19c	8,760 hr/yr	2.32	2.32	0.00	0.00	0.00	0.00	0.00

EU	Condition[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
CP20	8,760 hr/yr	1.48	1.48	0.00	0.00	0.00	0.00	0.00
CP21	8,760 hr/yr	1.48	1.48	0.00	0.00	0.00	0.00	0.00
CP22	8,760 hr/yr	1.48	1.48	0.00	0.00	0.00	0.00	0.00
CP24	8,760 hr/yr	0.05	0.05	0.08	0.24	0.01	0.04	0.01
CP25	8,760 hr/yr	0.05	0.05	0.08	0.24	0.01	0.04	0.01
CP26	8,760 hr/yr	0.79	0.79	1.16	3.9	0.06	0.57	0.2
CP27	8,760 hr/yr	0.79	0.79	1.16	3.9	0.06	0.57	0.2
CP28	500 hr/yr	0.06	0.06	10.47	0.86	0.01	0.03	0.03
CP29	500 hr/yr	0.06	0.06	10.47	0.86	0.01	0.03	0.03
CP30a	8,760 hr/yr	0.29	0.29	0.00	0.00	0.00	0.00	0.00
CP30b	8,760 hr/yr	0.29	0.29	0.00	0.00	0.00	0.00	0.00
CP32	18,000 gal/yr	0.00	0.00	0.00	0.00	0.00	0.15	0.01
CP34	500 hr/yr	0.02	0.02	1.35	0.09	0.01	0.04	0.01
CP35	500 hr/yr	0.02	0.02	1.35	0.09	0.01	0.04	0.01
CP37	8,760 hr/yr	0.05	0.05	0.08	0.24	0.01	0.04	0.01
CP41	8,760 hr/yr	0.01	0.01	0.10	0.04	0.01	0.01	0.01
CP42	8,760 hr/yr	0.01	0.01	0.10	0.04	0.01	0.01	0.01
CP44	8,760 hr/yr	0.03	0.03	0.43	0.36	0.01	0.02	0.01

[1]The quantities in this column are not intended as enforceable permit limits unless stated otherwise in this permit.

b. The permittee shall not allow actual emissions from the individual emission units to exceed the emission rates and emission concentrations listed in Table III-E-3. *[AQR 12.5.2.3]*

Table III-E-3: Emissions – Caesars Palace

EU	Rating	NO_x/CO (ppm)[1]	NO_x (lbs/hr)	CO (lbs/hr)
CP01	35.4 MMBtu/hr	NO_x 29/CO 10	1.24	0.26
CP02	35.4 MMBtu/hr	NO_x 29/CO 10	1.24	0.26
CP03	33.475 MMBtu/hr	NO_x 30/CO 10	1.23	0.25
CP04	33.475 MMBtu/hr	NO_x 30/CO 10	1.23	0.25
CP05	33.475 MMBtu/hr	NO_x 30/CO 10	1.23	0.25
CP26	24.0 MMBtu/hr	NO_x 9/CO 50	0.26	0.89
CP27	24.0 MMBtu/hr	NO_x 9/CO 50	0.26	0.89

[1]Corrected to 3% oxygen.

c. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant in excess of an average of 20% opacity for a period of more than 6 consecutive minutes. *[AQR 26.1]*

3. Production Limitations

a. The permittee shall limit the operation of each of the diesel-fired emergency generators and the fire pump for testing and maintenance purposes to 100 hours per year. The permittee may operate each of the emergency generators and the fire pump up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EUs: CP13 through CP17). *[40 CFR Part 63.6640(f)(i)(ii)]*

b. The permittee shall limit the operation of each of the diesel-fired emergency generators and the fires pumps for testing and maintenance purposes to 100 hours per year. The permittee may operate each emergency generator and fire pump up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EUs: CP28, CP29, CP34, and CP35). *[40 CFR Part 60.4211(f)]*

c. The permittee shall limit the maximum throughput of all gasoline products to 18,000 gallons per any consecutive 12 months (EU: CP32). *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

4. Control Requirements

Boilers/Water Heaters [AQR 12.5.2.12]

a. The permittee shall combust only natural gas in all boilers/heaters. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

b. The permittee shall operate and maintain all boilers/heaters in accordance with the manufacturer's O&M manual for emissions-related components and good combustion practices. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

c. The permittee shall operate and maintain the 35.4 MMBtu/hr boilers (EUs: CP01 and CP02) with burners that have a manufacturer's maximum emission concentration of 29 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 7, Revision 0 (01/29/2008)]*

d. The permittee shall operate and maintain the 35.4 MMBtu/hr boilers (EUs: CP01 and CP02) with burners that have a manufacturer's maximum emission concentration of 10 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 7, Revision 0 (01/29/2008)]*

e. The permittee shall operate and maintain the 33.475 MMBtu/hr boilers (EUs: CP03 through CP05) with burners that have a manufacturer's maximum emission concentration of 30 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

f. The permittee shall operate and maintain the 33.475 MMBtu/hr boilers (EUs: CP03 through CP05) with burners that have a manufacturer's maximum emission concentration of 10 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

g. The permittee shall operate and maintain the 1.0 MMBtu/hr boiler (EU: CP07) with burners that have a manufacturer's maximum emission concentration of 14 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

h. The permittee shall operate and maintain the 1.0 MMBtu/hr boiler (EU: CP07) with burners that have a manufacturer's maximum emission concentration of 77 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

i. The permittee shall operate and maintain the 1.50 MMBtu/hour boilers (EUs: CP24 and CP25) with burners that have a manufacturer's maximum emission concentration of 10 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

j. The permittee shall operate and maintain the 1.50 MMBtu/hour boilers (EUs: CP24 and CP25) with burners that have a manufacturer's maximum emission concentration of 50 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

k. The permittee shall operate and maintain the two 24.0 MMBtu/hr boilers (EUs: CP26 and CP27) with burners that have a manufacturer's maximum emission concentration of 9 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 7, Revision 0 (01/29/2008)]*

l. The permittee shall operate and maintain the two 24.0 MMBtu/hr boilers (EUs: CP26 and CP27) with burners that have a manufacturer's maximum emission concentration of 50 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 7, Revision 0 (01/29/2008)]*

m. The permittee shall operate and maintain the 1.5 MMBtu/hr boiler (EU: CP37) with burners that have a manufacturer's maximum emission concentration of 10 ppm NO_x, corrected to 3% oxygen. *[AQR 12.5.2.6]*

n. The permittee shall operate and maintain the 1.5 MMBtu/hr boiler (EU: CP37) with burners that have a manufacturer's maximum emission concentration of 50 ppm CO, corrected to 3% oxygen. *[AQR 12.5.2.6]*

Diesel Generators/Fire Pumps

o. The permittee shall operate and maintain all diesel generators and fire pumps in accordance with the manufacturer's O&M manual for emissions-related components. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

p. The permittee shall operate each of the diesel engines with turbochargers and aftercoolers (EUs: CP13 through CP17, CP28, CP29, CP34, and CP35). *[NSR ATC, Modification 7, Revision 0 (01/29/2008); NSR ATC, Modification 11, Revision 0 (02/19/2009)]*

q. The permittee shall ensure that the diesel engines are in compliance with 40 CFR Part 60, Subpart IIII, by meeting of all of the following (EUs: CP28, CP29, CP34, and CP35): *[40 CFR Part 60.4206]*

   i. operation of the engine according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer; and

ii. installation and configuration of the engine according to the manufacturer's specifications.

Cooling Towers

r. The permittee shall operate and maintain all cooling towers in accordance with the manufacturer's O&M manual for emissions-related components. No chromium-containing compounds shall be used for water treatment. *[40 CFR Part 63.402]*

s. The permittee shall operate the cooling towers with drift eliminators that have a manufacturer's maximum drift rate of 0.005% (EUs: CP19a through CP22). *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

t. The permittee shall operate the cooling towers with drift eliminators that have a manufacturer's maximum drift rate of 0.001% (EUs: CP30a and CP30b). *[NSR ATC, Modification 7, Revision 0 (01/29/2008)]*

u. The permittee shall limit the TDS content of each cooling tower's circulation water to 5,000 ppm. *[Title V OP (12/19/2019)]*

Gasoline Dispensing

v. The permittee shall implement control technology requirements on gasoline dispensing equipment (EU: CP32). *[40 CFR Part 63, Subpart CCCCCC]*

w. The permittee shall install and operate all Phase I vapor recovery equipment according to certifications specified by the manufacturer, and shall maintain the equipment to be leak-free, vapor-tight, and in proper working order. *[AQR 12.5.2.6]*

x. From October 1 to March 31 every year in the Las Vegas Valley, the Eldorado Valley, the Ivanpah Valley, the Boulder City limits, and any area within three miles of these areas, no gasoline intended as a final product for fueling motor vehicles shall be supplied or sold by any person; sold at retail; sold to a private or a municipal fleet for consumption; or introduced into any motor vehicle by any person unless the gasoline has at least 3.5 percent oxygen content by weight. *[AQR 53.1.1 & 53.2.1]*

y. If a gasoline storage tank in the Las Vegas Valley, the Eldorado Valley, the Ivanpah Valley, the Boulder City limits, and any area within three miles of these areas, receives its last gasoline delivery with less than 3.5 percent oxygen content by weight before September 15, gasoline dispensed from that tank will be exempt from enforcement of Section 53.2.1 until the first delivery date after October 1. *[AQR 53.5.1.1]*

z. The permittee shall not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Preventative measures to be taken include, but are not limited to, the following: *[40 CFR Parts 63.11116 and 63.11117]*

i. Minimize gasoline spills;

ii. Clean up spills as expeditiously as practicable;

iii. Cover all open gasoline containers and all gasoline storage tank fill pipes with a gasketed seal when not in use; and

iv. Only load gasoline into storage tanks using a submerged fill tube where the greatest distance from the bottom of the storage tank to the point of the fill tube opening is no more than six inches.

aa. The permittee shall install, maintain, and operate a Phase I vapor recovery system on all gasoline storage tanks (EU: CP32) that meets the following requirements: *[AQR 12.5.2.6]*

i. The Phase I vapor recovery system shall be rated with at least 90.0 percent control efficiency when in operation. This system shall be certified by an industry-recognized certification body, i.e., California Resources Air Board (CARB) or equivalent.

ii. The Phase I vapor recovery system shall be a dual-point vapor balance system, as defined by 40 CFR Part 63.11132, in which the storage tank is equipped with an entry port for a gasoline fill pipe and a separate exit port for a vapor connection.

iii. All Phase I vapor recovery equipment shall be installed and operated in accordance with manufacturer specifications and certification requirements.

iv. All Phase I vapor recovery equipment, including the vapor line from the gasoline storage tanks to the gasoline cargo tank, shall be maintained in good working order and vapor-tight, as defined in 40 CFR Part 63.11132.

v. All vapor connections and lines on storage tanks shall be equipped with closures that seal upon disconnect.

bb. The vapor balance system shall be designed so that the pressure in the cargo tank does not exceed 18 inches of water pressure or 5.9 inches of water vacuum during product transfer.

cc. Liquid fill and vapor return adapters for all systems shall be equipped and secured with vapor-tight caps after each delivery. *[AQR 12.5.2.6]*

dd. A pressure/vacuum (PV) vent valve on each gasoline storage tank system (EU: CP32) shall be installed, maintained, and operated in accordance with manufacturer's specifications.

i. The pressure specifications for PV vent valves shall be a positive pressure setting of 2.5 to 6.0 inches of water and a negative pressure setting of 6.0 to 10.0 inches of water.

ii. The total leak rate of all PV vent valves at the affected facility, including connections, shall not exceed 0.17 ft^3 per hour at a pressure of 2.0 inches of water and 0.63 ft^3 per hour at a vacuum of 4 inches of water. *[AQR 12.5.2.6]*

ee. The vapor balance system shall be capable of meeting the static pressure performance requirement in 40 CFR Part 63, Subpart CCCCCC. *[AQR 12.5.2.6]* ff. The permittee shall comply with good management practices during the unloading of gasoline cargo tanks, as follows: *[AQR 12.5.2.6]*

i. All hoses in the vapor balance system shall be properly connected.

ii. The adapters or couplers that attach to the vapor line on the storage tank shall have closures that seal upon disconnect.

iii. All vapor return hoses, couplers, and adapters used in the gasoline delivery shall be vapor-tight.

iv. All tank truck vapor return equipment shall be compatible in size and form a vapor-tight connection with the vapor balance equipment on the gasoline storage tank.

v. All hatches on the tank truck shall be closed and securely fastened.

vi. The filling of storage tanks shall be limited to unloading from vapor-tight gasoline cargo tanks carrying documentation onboard that the cargo tank has met the specifications of EPA Test Method 27.

Other

gg. The permittee shall not cause, suffer, or allow any source to discharge air contaminants (or other materials) in quantities that will cause a nuisance, including excessive odors. *[AQR 40 & AQR 43]*

5. Monitoring

Boilers/Water Heaters

a. The permittee shall install and utilize nonresettable fuel meters such that the daily consumption of natural gas can be established for each applicable boiler (EUs: CP01 through CP05, CP26, and CP27). *[AQR 12.5.2.6(d) and 40 CFR Part 60.48c(g)(1)]*

b. The permittee shall perform a burner efficiency test twice each calendar year, at least five months apart but no more than seven (EUs: CP01 through CP05, CP26, and CP27). *[AQR 12.5.2.6(d)]*

c. The permittee shall conduct burner efficiency tests in accordance with the manufacturer's O&M manual and good combustion practices. Alternative methods may be used upon Control Officer approval (EUs: CP01 through CP05, CP26, and CP27). *[AQR 12.5.2.6(d)]*

d. The permittee may perform a burner efficiency test once each calendar year if the actual hours of operation are less than 50. To exercise this option, the permittee must install an hour meter and begin keeping written records before the start of the calendar year (EUs: CP01 through CP05, CP26, and CP27). *[AQR 12.5.2.6(d)]*

e. The permittee may replace one contemporaneously-required burner efficiency test with a performance test that has acceptable results (EUs: CP01 through CP05, CP26, and CP27). *[AQR 12.5.2.6(d)]*

Diesel Generators/Fire Pumps

f. The permittee shall monitor operating hours for each applicable diesel engine utilizing nonresettable hour meters when operated for testing, maintenance, or during emergencies (EUs: CP13 through CP17, CP28, CP29, CP34, and CP35). *[AQR 12.5.2.6(d)]*

Visible Emissions

g. The responsible official shall sign and adhere to the *Visible Emissions Check Guidebook* and keep a copy of the signed guide on-site at all times. *[AQR 12.5.2.6(d)]*

h. The permittee shall conduct a visual emissions check at least quarterly on each diesel-fired emergency generator and fire pump while in operation. *[AQR 12.5.2.6(d)]*

i. If no plume appears to exceed the opacity standard during the visible emissions check, the date, location, and results shall be recorded, along with the viewer's name. *[AQR 12.5.2.6(d)]*

j. If a plume appears to exceed the opacity standard, the permittee shall do one of the following: *[AQR 12.5.2.6(d)]*

   i. Immediately correct the perceived exceedance, then record the first and last name of the person who performed the emissions check, the date the check was performed, the unit(s) observed, and the results of the observation; or

   ii. Call a certified VEE reader to perform an EPA Method 9 evaluation.

      a. For sources required to have a certified reader on-site, the reader shall start Method 9 observations within 15 minutes of the initial observation. For all other sources, the reader shall start Method 9 observations within 30 minutes of the initial observation.

      b. If no opacity exceedance is observed, the certified VEE reader shall record the first and last name of the person who performed the VEE, the date the VEE was performed, the unit(s) evaluated, and the results. A Method 9 VEE form shall be completed for each emission unit that was initially perceived to have exceeded the opacity limit, and the record shall also indicate:

         (1) The cause of the perceived exceedance;

         (2) The color of the emissions; and

         (3) Whether the emissions were light or heavy.

      c. If an opacity exceedance is observed, the certified VEE reader shall take immediate action to correct the exceedance. The reader shall then record the first and last name of the person performing the VEE, the date the VEE was performed, the unit(s) evaluated, and the results. A Method 9 VEE form shall be completed for each reading identified, and the record shall also indicate:

         (1) The cause of the exceedance;

         (2) The color of the emissions;

(3) Whether the emissions were light or heavy;

(4) The duration of the emissions; and

(5) The corrective actions taken to resolve the exceedance.

k. Any scenario of visible emissions noncompliance can and may lead to enforcement action. *[AQR 12.5.2.6(d)]*

Cooling Towers

l. The permittee shall monitor the TDS in the cooling tower circulation water monthly. The permittee may use a conductivity meter or an equivalent method approved in advance by the Control Officer to determine TDS. *[AQR 12.5.2.6(d)]*

Gasoline Dispensing

m. The permittee shall monitor the combined throughput of gasoline each month (EU: CP32). *[AQR 12.5.2.6(d)]*

n. The permittee shall monitor the fuel storage and dispensing system (EU: CP32) to determine if components of the system are in compliance with the control requirements of this permit. The monitoring shall consist of, but not be limited to, the following: *[40 CFR Part 63.11125]*

   i. The permittee shall inspect daily for gasoline spills, and record the times and dates the source became aware of a spill and cleaned it up.

   ii. The permittee shall inspect covers on gasoline containers and fill-pipes after each delivery, and record the dates of fuel deliveries and corresponding inspections.

   iii. The permittee shall record the date and approximate volume of gasoline sent to open waste collection systems that collect recyclable gasoline.

6. Testing

Performance Tests

a. Performance testing shall be the instrument for determining compliance with the emission limitations set forth in this permit for all boilers that have a heat input rating equal to or greater than 10.0 MMBtu/hr (EUs: CP01 through CP05, CP26, and CP27). *[AQR 12.5.2.8(a) and DAQ's "Guidelines for Source Testing"]*

b. The permittee shall conduct performance tests on each boiler (EUs: CP01 through CP05, CP26, and CP27) every five years, and no later than 90 days after the anniversary date of the last performance test. *[AQR 12.5.2.8(a) and DAQ's "Guidelines for Source Testing"]*

Table III-E-4: Performance Testing Protocol Requirements

Test Point	Pollutant	Method
Boiler Exhaust Outlet Stack	NO_x	EPA Method 7E
Boiler Exhaust Outlet Stack	CO	EPA Method 10 analyzer
Stack Gas Parameters	—	EPA Methods 1, 2, 3A, and 4

Gasoline Dispensing

c. The permittee shall conduct Phase I vapor recovery tests in accordance with the CARB-approved vapor recovery test procedures (as revised) listed in Table III-E-5, as applicable. *[AQR 12.5.2.8(a)]*

Table III-E-5: Vapor Recovery System Testing Procedures and Schedules

Type of Vapor Recovery System	Test Procedure	Frequency
Phase I Vapor Balance System	Pressure Decay/Leak test: TP201.3B (as revised for AST)	Initial and every three years thereafter
	Static Torque of Rotatable Phase I Adaptors CARB procedure TP-201.1B (With swivel adapters only)	Initial and every three years thereafter
	Leak Rate and Cracking Pressure of Pressure/Vacuum Vent Valves: CARB procedure TP-201.1E (as revised)	Initial and every three years thereafter
	Flow rate Test: CC_VRTP_1	Initial and every three years thereafter

d. The permittee shall submit, by mail, fax, or hand delivery, a Division of Air Quality (DAQ)-approved vapor recovery test notification form (available on the DAQ website) to schedule each vapor recovery test with the Stationary Sources Section supervisor at least 30 calendar days before the anticipated date of testing, unless otherwise specified in this permit. *[AQR 12.5.2.8(a)]*

e. Any prior approved scheduled vapor recovery system test cannot be canceled and/or rescheduled without the Control Officer's prior approval. *[AQR 12.5.2.8(a)]*

f. The permittee shall conduct Phase I vapor recovery system testing on affected gasoline dispensing equipment according to the following requirements: *[AQR 12.5.2.8(a)]*

i. The permittee shall conduct and pass an initial vapor recovery system test within 180 days of startup of new equipment, or within 90 days after completion of repairs or reconstruction where the integrity of the vapor recovery system has been affected by the repair or reconstruction. Routine maintenance, including the replacement of hoses, nozzles, and efficiency compliance devices (e.g., bellows, face shield, splash guard, etc.), does not require an initial vapor recovery system test.

ii. The permittee shall conduct and pass subsequent Phase I vapor recovery system tests on or before the anniversary date of the previous successful test at the frequency specified in Table III-E-5.

iii. Each vapor recovery system test may be witnessed by a DAQ inspector.

g. The permittee shall submit a Gasoline Dispensing Operation Certification of Vapor Recovery System Test Results Submittal Form (available on the DAQ website), along with associated test results, to the Control Officer after each vapor recovery system test. The submittal form shall be: *[AQR 12.5.2.8(a)]*

i. Complete and signed by the Responsible Official for the equipment being tested. The Responsible Official must certify that the test results are true, accurate, and complete.

ii. Submitted by mail, by fax, or in person.

iii. Submitted by the source, or by the permittee's testing company or consultant. However, the source is the responsible party and must ensure that the test report is delivered to DAQ within the applicable time frame.

h. If the source passes or fails the vapor recovery system test, the permittee shall submit the test results report to the Control Officer within 60 days of the date of the vapor recovery system test.

i. If the source fails a vapor recovery system test: *[Clark County Department of Air Quality Source Testing Guidelines (9/19/2019)]*

i. The permittee shall notify the Control Officer, by email or phone, within 24 hours of equipment test failure. If repairs can be made within five working days of the original scheduled test date, the permittee shall make the repairs and pass the required test(s).

ii. If the equipment cannot be repaired in five working days, the permittee shall make all necessary repairs and schedule a retest of the affected facility by submitting a new Test Notification Form to the Control Officer by mail, fax, or hand delivery no later than three business days before the new test date.

iii. After retesting (pass/fail), the owner/operator shall submit a Test Results Submittal Form (available on the DAQ website) and supporting test documents to the Control Officer within 15 days of completion.

iv. The permittee shall continue retesting until the affected facility successfully passes all aspects of the vapor recovery system test.

j. The Control Officer may require the permittee to conduct any test after a failed vapor recovery system test in the presence of a DAQ representative. *[AQR 12.5.2.8(a)]*

7. Recordkeeping

a. The permittee shall maintain records on site that include, at a minimum: *[AQR 12.5.2.6(d)]*

i. Dates and times when visible emissions checks and observations are made, and the corrective steps taken to bring opacity into compliance;

ii. Monthly TDS content of cooling tower circulation water;

iii. Log book of all inspections, maintenance, and repairs, as specified in this document;

iv. Records of burner efficiency testing, as specified in this permit;

v. Results of performance testing;

vi. Records of location changes for nonroad engines, if applicable; and

vii. Gasoline-dispensing records shall contain, at a minimum (EU: CP32): *[AQR 12.5.2.6(d) and 40 CFR Part 63.11120]*

1. Equipment inspections, including findings and corrective actions;

2. Maintenance on storage and distribution equipment, including a general description of location(s) and part(s);

3. Date and time that storage and distribution equipment was taken out of service;

4. Date of repair or replacement of storage and distribution equipment/parts;

5. Deviations from permit requirements resulting in excess emissions;

6. Deviations from permit requirements not resulting in excess emissions (reported annually);

7. Daily total combined throughput of gasoline;

8. Monthly combined total throughput of gasoline; and

9. Calendar year annual emissions for the entire source (reported annually).

b. The permittee shall maintain records on site and report the following information semiannually: *[AQR 12.5.2.6(d)]*

i. Monthly amount of natural gas consumed (in MMBtu, scf, or therms) for each boiler (EUs: CP01 through CP05, CP26 and CP27). *[40 CFR Part 60.48c(g)(1)]*

ii. Date and duration of operation of generators and fire pumps for emergency use, including documentation justifying use during the emergency (EUs: CP13 through CP17, CP28, CP29, CP34 and CP35); and

iii. Date and duration of operation of generators and fire pumps for testing, maintenance, and nonemergency use (EUs: CP13 through CP17, CP28, CP29, CP34, and CP35); and

iv. Monthly, consecutive 12-month total of gasoline throughput *[40 CFR Part 63.11116(b)]*.

c. The permittee shall include, for all inspections, logs, visible emission checks, and testing required under monitoring, recordkeeping, and reporting sections, at least the date and time, the name of the person performing the action, the results or findings, and the type of corrective action taken (if required). *[AQR 12.5.2.6(d)]*

F. PARIS CASINO RESORT

1. Emission Units

a. The stationary source activities at Paris Casino Resort, covered by this Part 70 OP, consist of the emission units and associated appurtenances summarized in Table III-F-1. *[AQR 12.5.2.3; NSR ATC, Modification 7, Revision 0 (01/29/2008); NSR ATC, Modification 10, Revision 0 (12/15/2008); NSR ATC, Modification 12, Revision 1, (08/20/2009); NSR ATC, Modification 14, (10/09/2009); NSR ATC, Modification 15, Revision 0 (03/20/2010); Title V 70 OP (05/29/2013), (03/28/2016), and (12/19/2019); and Application for Renewal of Part 70 OP (09/25/2020)]*

Table III-F-1: Summary of EUs – Paris Casino Resort

EU	Description	Rating	Make	Model No.	Serial No.
PA12	Natural Gas Boiler #4	3.5 MMBtu/hr	Bryan	RV350S-150-FDG-LX	81362
PA13	Natural Gas Boiler #5	3.5 MMBtu/hr	Bryan	RV350S-150-FDG-LX	81349
PA14	Natural Gas Boiler #3	17.0 MMBtu/hr	Bryan	RW1700W-FDG-LX	81458
PA15	Natural Gas Boiler #1	21.0 MMBtu/hr	Bryan	RW2100W-FDG-LX	81444
PA16	Natural Gas Boiler #2	21.0 MMBtu/hr	Bryan	RW2100W-FDG-LX	81457
PA17	Emergency Generator #1 DOM: 03/25/1998	2,100kW	Cummins	QSW73	79652
		2,816 hp		CW73-G	66300058
PA18	Emergency Generator #2 DOM: 02/26/1998	2,100kW	Cummins	QSW73	79651
		2,816 hp		CW73-G	66300040
PA19	2-Cell Cooling Tower #1	4,725 gpm	Baltimore Aircoil	33758-2W	97221981 & 97222002
PA20	2-Cell Cooling Tower #2	4,725 gpm	Baltimore Aircoil	33758-2W	97222011 & 97222001
PA21	2-Cell Cooling Tower #3	4,725 gpm	Baltimore Aircoil	33758-2W	97222021 & 97221992
PA22	2-Cell Cooling Tower #4	4,725 gpm	Baltimore Aircoil	33758-2W	97221991 & 97222012
PA23	2-Cell Cooling Tower #5	4,725 gpm	Baltimore Aircoil	33758-2W	97222022 & 97221982
PA28	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	FW1950	0409522881
PA29	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	FW1950	092086486
PA30	Natural Gas Pool Heater	1.95 MMBtu/hr	RBI Futera II	FW1950	092084697
PA31	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	FW1950	071983421

EU	Description	Rating	Make	Model No.	Serial No.
PA32	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	FW1950	021261112
PA33	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	FW1950	121160719
PA34	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	FW1950	011260847
PA35	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	FW1950	021982198
PA36	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	FW1950	051570836

2. Emission Limitations

The permittee shall limit the actual emissions from each emission unit to the PTE listed in Table III-F-2. *[NSR ATC, Modification 7, Revision 0 (01/29/2008); NSR ATC, Modification 10, Revision 0 (12/15/2008); NSR ATC, Modification 12, Revision 1, (08/20/2009); NSR ATC, Modification 14, (10/09/2009); NSR ATC, Modification 15, Revision 0 (03/20/2010); and Title V 70 OP (05/29/2013), (03/28/2016), and (12/19/2019)]*

Table III-F-2: PTE (tons per year) – Paris Casino Resort

EU	Conditions[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
PA12	8,760 hr/yr	0.13	0.13	0.48	1.27	0.01	0.09	0.04
PA13	8,760 hr/yr	0.13	0.13	0.48	1.27	0.01	0.09	0.04
PA14	8,760 hr/yr	0.56	0.56	2.72	6.28	0.04	0.40	0.14
PA15	8,760 hr/yr	0.69	0.69	3.36	7.75	0.06	0.50	0.17
PA16	8,760 hr/yr	0.69	0.69	3.36	7.75	0.06	0.50	0.17
PA17	500 hr/yr	0.49	0.49	16.90	3.87	0.01	0.50	0.02
PA18	500 hr/yr	0.49	0.49	16.90	3.87	0.01	0.50	0.02
PA19	8,760 hr/yr	1.22	1.22	0.00	0.00	0.00	0.00	0.00
PA20	8,760 hr/yr	1.22	1.22	0.00	0.00	0.00	0.00	0.00
PA21	8,760 hr/yr	1.22	1.22	0.00	0.00	0.00	0.00	0.00
PA22	8,760 hr/yr	1.22	1.22	0.00	0.00	0.00	0.00	0.00
PA23	8,760 hr/yr	1.22	1.22	0.00	0.00	0.00	0.00	0.00
PA28	8,760 hr/yr	0.06	0.06	0.10	0.32	0.01	0.05	0.02
PA29	8,760 hr/yr	0.06	0.06	0.10	0.32	0.01	0.05	0.02
PA30	8,760 hr/yr	0.06	0.06	0.10	0.32	0.01	0.05	0.02
PA31	8,760 hr/yr	0.06	0.06	0.10	0.32	0.01	0.05	0.02
PA32	8,760 hr/yr	0.06	0.06	0.10	0.32	0.01	0.05	0.02
PA33	8,760 hr/yr	0.06	0.06	0.10	0.32	0.01	0.05	0.02
PA34	8,760 hr/yr	0.06	0.06	0.10	0.32	0.01	0.05	0.02
PA35	8,760 hr/yr	0.06	0.06	0.10	0.70	0.01	0.05	0.02
PA36	8,760 hr/yr	0.06	0.06	0.84	0.70	0.01	0.05	0.02

[1]The quantities in this column are not intended as enforceable permit limits unless stated otherwise in this permit.

a. The permittee shall not allow actual emissions from the individual emission units to exceed the emission rates and emission concentrations listed in Table III-F-3. *[Title V OP (05/29/2013)]*

Table III-F-3: Emissions – Paris Casino Resort

EU	Rating	NO_x/CO (ppm)[1]	NO_x (lbs/hr)	CO (lbs/hr)
PA14	17.0 MMBtu/hr	NO_x 30/CO 114	0.62	1.44
PA15	21.0 MMBtu/hr	NO_x 30/CO 114	0.77	1.78
PA16	21.0 MMBtu/hr	NO_x 30/CO 114	0.77	1.78

[1]Corrected to 3% oxygen.

b. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant in excess of an average of 20% opacity for a period of more than 6 consecutive minutes. *[AQR 26.1]*

3. Production Limitations

a. The permittee shall limit the operation of each of the diesel-fired emergency generators for testing and maintenance purposes to 100 hours per year. The permittee may operate each of the emergency generators up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EUs: PA17 and PA18). *[40 CFR Part 63.6640(f)(i)(ii)]*

4. Control Requirements

Boilers/Water Heaters

a. The permittee shall combust only natural gas in all boilers/heaters. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

b. The permittee shall operate and maintain all boilers/heaters in accordance with the manufacturer's O&M manual for emissions-related components and good combustion practices. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

c. The permittee shall operate and maintain the 3.5 MMBtu/hour boilers (EUs: PA12 and PA13) with burners that have a manufacturer's maximum emission concentration of 26 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

d. The permittee shall operate and maintain the 3.5 MMBtu/hour boilers (EUs: PA12 and PA13) with burners that have a manufacturer's maximum emission concentration of 111 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

e. The permittee shall operate and maintain the 17.0 MMBtu/hr boiler (EU: PA14) with burners that have a manufacturer's maximum emission concentration of 30 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

f. The permittee shall operate and maintain the 17.0 MMBtu/hr boiler (EU: PA14) with burners that have a manufacturer's maximum emission concentration of 114 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

g. The permittee shall operate and maintain the 21.0 MMBtu/hr boilers (EUs: PA15 and PA16) with burners that have a manufacturer's maximum emission concentration of 30 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

h. The permittee shall operate and maintain the 21.0 MMBtu/hr boilers (EUs: PA15 and PA16) with burners that have a manufacturer's maximum emission concentration of 114 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

i. The permittee shall operate and maintain the 1.95 MMBtu/hr boilers (EUs: PA28 through PA34) with burners that have a manufacturer's maximum emission concentration of 10 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 15, Revision 0 (03/20/2010)]*

j. The permittee shall operate and maintain the 1.95 MMBtu/hr boilers (EUs: PA28 through PA34) with burners that have a manufacturer's maximum emission concentration of 50 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 15, Revision 0 (03/20/2010)]*

k. The permittee shall operate and maintain the 1.95 MMBtu/hr boiler (EU: PA35) with burners that have a manufacturer's maximum emission concentration of 10 ppm NO_x, corrected to 3% oxygen. *[Title V OP (12/19/2019)]*

Diesel Generators [AQR 12.5.2.6]

l. The permittee shall operate and maintain all diesel generators in accordance with the manufacturer's O&M manual for emissions-related components. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

m. The permittee shall operate each of the diesel engine with turbochargers (EUs: PA17 and PA18). *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

Cooling Towers

n. The permittee shall operate and maintain all cooling towers in accordance with the manufacturer's O&M manual for emissions-related components. No chromium-containing compounds shall be used for water treatment. *[40 CFR Part 63.402]*

o. The permittee shall operate each of the cooling towers with drift eliminators that have a manufacturer's maximum drift rate of 0.005% (EUs: PA19 through PA23). *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

p. The permittee shall limit the TDS content of each cooling tower's circulation water to 5,000 ppm. *[Title V OP (12/19/2019)]*

Other

q. The permittee shall not cause, suffer, or allow any source to discharge air contaminants (or other materials) in quantities that will cause a nuisance, including excessive odors. *[AQR 40 & AQR 43]*

5. Monitoring

Boilers/Water Heaters

a. The permittee shall install and utilize nonresettable fuel meters such that the daily consumption of natural gas can be established for each applicable boiler (EUs: PA14, PA15, and PA16). *[AQR 12.5.2.6(d) and 40 CFR Part 60.48c(g)(1)]*

b. The permittee shall perform a burner efficiency test twice each calendar year, at least five months apart but no more than seven (EUs: PA14, PA15, and PA16). *[AQR 12.5.2.6(d)]*

c. The permittee shall conduct burner efficiency tests in accordance with the manufacturer's O&M manual and good combustion practices. Alternative methods may be used upon Control Officer approval (EUs: PA14, PA15, and PA16). *[AQR 12.5.2.6(d)]*

d. The permittee may perform a burner efficiency test once each calendar year if the actual hours of operation are less than 50. To exercise this option, the permittee must install an hour meter and begin keeping written records before the start of the calendar year (EUs: PA14, PA15, and PA16). *[AQR 12.5.2.6(d)]*

e. The permittee may replace one contemporaneously-required burner efficiency test with a performance test that has acceptable results (EUs: PA14, PA15, and PA16). *[AQR 12.5.2.6(d)]*.

Diesel Generators

f. The permittee shall monitor operating hours for each applicable diesel engine utilizing nonresettable hour meters. (EUs: PA17 and PA18). *[AQR 12.5.2.6(d)]*

Visible Emissions

g. The responsible official shall sign and adhere to the *Visible Emissions Check Guidebook* and keep a copy of the signed guide on-site at all times. *[AQR 12.5.2.6(d)]*

h. The permittee shall conduct a visual emissions check at least quarterly on each diesel-fired emergency generator while in operation. *[AQR 12.5.2.6(d)]*

i. If no plume appears to exceed the opacity standard during the visible emissions check, the date, location, and results shall be recorded, along with the viewer's name. *[AQR 12.5.2.6(d)]*

j. If a plume appears to exceed the opacity standard, the permittee shall do one of the following: *[AQR 12.5.2.6(d)]*

i. Immediately correct the perceived exceedance, then record the first and last name of the person who performed the emissions check, the date the check was performed, the unit(s) observed, and the results of the observation; or

ii. Call a certified VEE reader to perform an EPA Method 9 evaluation.

a. For sources required to have a certified reader on-site, the reader shall start Method 9 observations within 15 minutes of the initial observation. For all other sources, the reader shall start Method 9 observations within 30 minutes of the initial observation.

b. If no opacity exceedance is observed, the certified VEE reader shall record the first and last name of the person who performed the VEE, the date the VEE was performed, the unit(s) evaluated, and the results. A Method 9 VEE form shall be completed for each emission unit that was initially perceived to have exceeded the opacity limit, and the record shall also indicate:

(1) The cause of the perceived exceedance;

(2) The color of the emissions; and

(3) Whether the emissions were light or heavy.

c. If an opacity exceedance is observed, the certified VEE reader shall take immediate action to correct the exceedance. The reader shall then record the first and last name of the person performing the VEE, the date the VEE was performed, the unit(s) evaluated, and the results. A Method 9 VEE form shall be completed for each reading identified, and the record shall also indicate:

(1) The cause of the exceedance;

(2) The color of the emissions;

(3) Whether the emissions were light or heavy;

(4) The duration of the emissions; and

(5) The corrective actions taken to resolve the exceedance.

k. Any scenario of visible emissions noncompliance can and may lead to enforcement action. *[AQR 12.5.2.6(d)]*

Cooling Towers

l. The permittee shall monitor the TDS in the cooling tower circulation water monthly. The permittee shall use a conductivity meter or an equivalent method approved in advance by the Control Officer to determine TDS. *[AQR 12.5.2.6(d)]*

6. Testing

a. Performance testing shall be the instrument for determining compliance with emission limitations set forth in this permit for all boilers that have a heat input rating equal to or greater than 10.0 MMBtu/hr (EUs: PA14, PA15, and PA16). *[AQR 12.5.2.8(a) and Air Quality's Guidelines for Source Testing]*

b. The permittee shall conduct performance tests on each boiler (EUs: PA14, PA15, and PA16) every five years, and no later than 90 days after the anniversary date of the last performance test. *[AQR 12.5.2.8(a) and Air Quality's Guidelines for Source Testing]*

Table III-F-4: Performance Testing Protocol Requirements

Test Point	Pollutant	Method
Boiler Exhaust Outlet Stack	NO_x	EPA Method 7E
Boiler Exhaust Outlet Stack	CO	EPA Method 10 analyzer
Stack Gas Parameters	—	EPA Methods 1, 2, 3A, and 4

7. Recordkeeping

a. The permittee shall maintain records on site that include, at a minimum, the following: *[AQR 12.5.2.6(d)]*

i. Dates and times when visible emissions checks and observations are made, and the corrective steps taken to bring opacity into compliance;

ii. Monthly TDS content of cooling tower circulation water;

iii. Log book of all inspections, maintenance, and repairs, as specified in this permit;

iv. Records of burner efficiency testing;

v. Results of performance testing; and

vi. Records of location changes for nonroad engines, if applicable.

b. The permittee shall maintain records on site and report the following semiannually: *[AQR 12.5.2.6(d)]*

i. Monthly amount of natural gas consumed (in MMBtu, scf, or therms) for each boiler (EUs: PA14, PA15, and PA16); *[40 CFR Part 60.48c(g)(1)]*

ii. Date and duration of operation of emergency generators for testing, maintenance, and nonemergency use (EUs: PA17 and PA18); and

iii. Date and duration of operation of emergency generators for emergency use, including documentation justifying use during the emergency (EUs: PA17 and PA18).

c. The permittee shall include, for all inspections, logs, visible emission checks, and testing required under monitoring, recordkeeping, and reporting sections, at least the date and time, the name of the person performing the action, the results or findings, and the type of corrective action taken (if required). *[AQR 12.5.2.6(d)]*

G. THE LINQ HOTEL & CASINO

1. Emission Units

a. The stationary source activities at The LINQ Hotel & Casino covered by this Part 70 OP consist of the emission units and associated appurtenances summarized in Table III-G-1. *[AQR 12.5.2.3; NSR ATC, Modification 7, Revision 0 (01/29/2008); NSR ATC, Modification 10, Revision 0 (12/15/2008); NSR ATC, Modification 12, Revision 1, (08/20/2009); Title V OP (03/28/2016); and Application for Renewal of Part 70 OP (09/25/2020)]*

Table III-G-1: Summary of EUs – The LINQ Hotel & Casino

EU	Description	Rating	Make	Model No.	Serial No.
IP01	Natural Gas Boiler	1.25 MMBtu/hr	Ajax	WG-1250 D	82-34510
IP02	Natural Gas Boiler	1.25 MMBtu/hr	Ajax	WG-1250 D	82-34507
IP03	Natural Gas Boiler	1.25 MMBtu/hr	Ajax	WG-1250 D	82-34502
IP04	Natural Gas Boiler	16.738 MMBtu/hr	Kewanee	H3S 400HP	R8190
IP05	Natural Gas Boiler	16.738 MMBtu/hr	Kewanee	H3S 400-G0	R8191
IP06	Emergency Generator DOM: Pre-2006	470 kW	Caterpillar	SR4	6EA00547
		680 hp		3412	81Z01351
IP07	Emergency Generator DOM: Pre-2006	500 kW	Caterpillar	SR4	5NA05002
		755 hp		3412	81Z04033
IP08	Emergency Generator DOM: Pre-2006	600 kW	Caterpillar	SR4	6FA04856
		890 hp		3412	81Z07511
IP09	Emergency Generator DOM: Pre-2006	600 kW	Caterpillar	SR4	6FA05404
		890 hp		3412	81Z08595
IP10	Emergency Generator DOM: Pre-2006	280 kW	E.M. Generator	7083-7305	263120414
		375 hp	Detroit		
IP11	Emergency Generator DOM: Pre-2006	500 kW	Marathon Electric	580FDF4036FFPD1W	JB-95613
		670 hp	Detroit	71637305	16VA015737
IP38	Emergency Generator DOM: 2019	500 kW	Caterpillar	LC6	G6B25666
		762 hp	Caterpillar	C15	FTE04081

2. Emission Limitations

a. The permittee shall limit the actual emissions from each emission unit to the PTE listed in Table III-G-2. *[NSR ATC, Modification 7, Revision 0 (01/29/2008); NSR ATC, Modification 10, Revision 0 (12/15/2008); NSR ATC, Modification 12, Revision 1, (08/20/2009); Title V OP (03/28/2016); and Application for Renewal of Part 70 OP (09/25/2020)]*

Table III-G-2: PTE (tons per year) – The LINQ Hotel & Casino

EU	Condition[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
IP01	8,760 hr/yr	0.04	0.04	0.27	0.45	0.01	0.03	0.01
IP02	8,760 hr/yr	0.04	0.04	0.27	0.45	0.01	0.03	0.01
IP03	8,760 hr/yr	0.04	0.04	0.27	0.45	0.01	0.03	0.01
IP04	8,760 hr/yr	0.57	0.57	3.59	5.43	0.04	0.39	0.13
IP05	8,760 hr/yr	0.57	0.57	3.59	5.43	0.04	0.39	0.13
IP06	500 hr/yr	0.12	0.12	4.08	0.94	0.01	0.12	0.00
IP07	500 hr/yr	0.13	0.13	4.53	1.04	0.01	0.13	0.01
IP08	500 hr/yr	0.16	0.16	5.34	1.23	0.01	0.16	0.01
IP09	500 hr/yr	0.16	0.16	5.34	1.23	0.01	0.16	0.01
IP10	500 hr/yr	0.21	0.21	2.91	0.63	0.01	0.24	0.01
IP11	500 hr/yr	0.12	0.12	4.02	0.92	0.01	0.12	0.01
IP38	500 hr/yr	0.02	0.02	2.07	0.49	0.01	0.02	0.01

[1]The quantities in this column are not intended as enforceable permit limits unless stated otherwise in this permit.

b. The permittee shall not allow actual emissions from the individual emission units to exceed the emission rates and emission concentrations listed in Table III-G-3. *[NSR ATC, Modification 7, Revision 0 (01/29/2008)]*

Table III-G-3: Emissions – The LINQ Hotel & Casino

EU	Rating	NO_x/CO (ppm)[1]	NOx (lbs/hr)	CO (lbs/hr)
IP04	16.738 MMBtu/hr	NO_x 40.2/CO 100	0.82	1.24
IP05	16.738 MMBtu/hr	NO_x 40.2/CO 100	0.82	1.24

[1]Corrected to 3% oxygen.

c. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant in excess of an average of 20% opacity for a period of more than 6 consecutive minutes. *[AQR 26.1]*

3. Production Limitations

a. The permittee shall limit the operation of each of the diesel-fired emergency generators for testing and maintenance purposes to 100 hours per year. The permittee may operate each of the emergency generators up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EUs: IP06 through IP11). *[40 CFR Part 63.6640(f)(i)(ii)]*

b. The permittee shall limit the operation of the diesel-fired emergency generator for testing and maintenance purposes to 100 hours per year. The permittee may operate the emergency generator up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EU: IP38). *[40 CFR Part 60.4211(f)]*

4. Control Requirements

Boilers/Water Heaters [AQR 12.5.2.6]

a. The permittee shall combust only natural gas in all boilers/heaters. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

b. The permittee shall operate and maintain all boilers/heaters in accordance with the manufacturer's O&M manual for emissions-related components and good combustion practices. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

c. The permittee shall operate and maintain the 1.25 MMBtu/hr boilers (EUs: IP01 through IP03) with burners that have a manufacturer's maximum emission concentration of 40.2 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

d. The permittee shall operate and maintain the 1.25 MMBtu/hr boilers (EUs: IP01 through IP03) with burners that have a manufacturer's maximum emission concentration of 110.5 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

e. The permittee shall operate and maintain the 16.738 MMBtu/hr boilers (EUs: IP04 and IP05) with burners that have a manufacturer's maximum emission concentration of 40.2 ppm NO_x, corrected to 3% oxygen, and FGR control devices. *[NSR ATC, Modification 7, Revision 0 (01/29/2008)]*

f. The permittee shall operate and maintain the 16.738 MMBtu/hr boilers (EUs: IP04 and IP05) with burners that have a manufacturer's maximum emission concentration of 100 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 7, Revision 0 (01/29/2008)]*

Diesel Generators

g. The permittee shall operate and maintain all diesel generators and fire pumps in accordance with the manufacturer's O&M manual for emissions-related components. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

h. The permittee shall operate each of the emergency generators with turbochargers and aftercoolers (EUs: IP06 through IP09 and IP38). *[NSR ATC, Modification 10, Revision 0 (12/15/2008) and Application for Renewal of Part 70 OP (09/25/2020)]*

i. The permittee shall operate each of the emergency generators with turbochargers (EUs: IP10 and IP11). *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

j. The permittee shall ensure that the diesel engine is in compliance with 40 CFR Part 60, Subpart IIII, by meeting of all of the following (EU: IP38): *[40 CFR Part 60.4206]*

   i. operation of the engine according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer; and

   ii. installation and configuration of the engine according to the manufacturer's specifications.

Other

k. The permittee shall not cause, suffer, or allow any source to discharge air contaminants (or other materials) in quantities that will cause a nuisance, including excessive odors. *[AQR 40 & AQR 43]*

5. Monitoring

Boilers/Water Heaters

a. The permittee shall install and utilize nonresettable fuel meters such that the daily consumption of natural gas can be established for each applicable boiler (EUs: IP04 and IP05). *[AQR 12.5.2.6(d) and 40 CFR Part 60.48c(g)(1)]*

b. The permittee shall perform a burner efficiency test twice each calendar year, at least five months apart but no more than seven (EUs: IP04 and IP05). *[AQR 12.5.2.6(d)]*

c. The permittee shall conduct burner efficiency tests in accordance with the manufacturer's O&M manual and good combustion practices. Alternative methods may be used upon Control Officer approval (EUs: IP04 and IP05). *[AQR 12.5.2.6(d)]*

d. The permittee may perform a burner efficiency test once each calendar year if the actual hours of operation are less than 50. To exercise this option, the permittee must install an hour meter and begin keeping written records before the start of the calendar year (EUs: IP04 and IP05). *[AQR 12.5.2.6(d)]*

e. The permittee may replace one contemporaneously-required burner efficiency test with a performance test that has acceptable results (EUs: IP04 and IP05). *[AQR 12.5.2.6(d)]*

Diesel Generators

f. The permittee shall monitor operating hours for each applicable diesel engine utilizing nonresettable hour meters. (EUs: IP06 through IP11 and IP38). *[AQR 12.5.2.6(d)]*

Visible Emissions

g. The responsible official shall sign and adhere to the *Visible Emissions Check Guidebook* and keep a copy of the signed guide on-site at all times. *[AQR 12.5.2.6(d)]*

h. The permittee shall conduct a visual emissions check at least quarterly on each diesel-fired emergency generator while in operation. *[AQR 12.5.2.6(d)]*

i. If no plume appears to exceed the opacity standard during the visible emissions check, the date, location, and results shall be recorded, along with the viewer's name. *[AQR 12.5.2.6(d)]*

j. If a plume appears to exceed the opacity standard, the permittee shall do one of the following: *[AQR 12.5.2.6(d)]*

   i. Immediately correct the perceived exceedance, then record the first and last name of the person who performed the emissions check, the date the check was performed, the unit(s) observed, and the results of the observation; or

ii. Call a certified VEE reader to perform an EPA Method 9 evaluation.

a. For sources required to have a certified reader on-site, the reader shall start Method 9 observations within 15 minutes of the initial observation. For all other sources, the reader shall start Method 9 observations within 30 minutes of the initial observation.

b. If no opacity exceedance is observed, the certified VEE reader shall record the first and last name of the person who performed the VEE, the date the VEE was performed, the unit(s) evaluated, and the results. A Method 9 VEE form shall be completed for each emission unit that was initially perceived to have exceeded the opacity limit, and the record shall also indicate:

(1) The cause of the perceived exceedance;

(2) The color of the emissions; and

(3) Whether the emissions were light or heavy.

c. If an opacity exceedance is observed, the certified VEE reader shall take immediate action to correct the exceedance. The reader shall then record the first and last name of the person performing the VEE, the date the VEE was performed, the unit(s) evaluated, and the results. A Method 9 VEE form shall be completed for each reading identified, and the record shall also indicate:

(1) The cause of the exceedance;

(2) The color of the emissions;

(3) Whether the emissions were light or heavy;

(4) The duration of the emissions; and

(5) The corrective actions taken to resolve the exceedance.

k. Any scenario of visible emissions noncompliance can and may lead to enforcement action. *[AQR 12.5.2.6(d)]*

6. Testing

a. Performance testing shall be the instrument for determining compliance with the emission limitations set forth in this permit for all boilers that have a heat input rating equal to or greater than 10.0 MMBtu/hr (EUs: IP04 and IP05). *[AQR 12.5.2.8(a) and DAQ's "Guidelines for Source Testing"]*

b. The permittee shall conduct performance tests on each boiler (EUs: IP04 and IP05) every five years, and no later than 90 days after the anniversary date of the last performance test. *[AQR 12.5.2.8(a) and DAQ's "Guidelines for Source Testing"]*

Table III-G-4: Performance Testing Protocol Requirements

Test Point	Pollutant	Method
Boiler Exhaust Outlet Stack	NO_x	EPA Method 7E
Boiler Exhaust Outlet Stack	CO	EPA Method 10 analyzer
Stack Gas Parameters	—	EPA Methods 1, 2, 3A, and 4

7. Recordkeeping

a. The permittee shall maintain records on site that include, at minimum, the following: *[AQR 12.5.2.6(d)]*

i. Dates and times when visible emissions checks and observations are made, and the corrective steps taken to bring opacity into compliance;

ii. Log book of all inspections, maintenance, and repairs, as specified in this permit;

iii. Records of burner efficiency testing;

iv. Results of performance testing; and

v. Records of location changes for nonroad engines, if applicable.

b. The permittee shall maintain records on site and report the following semiannually: *[AQR 12.5.2.6(d)]*

i. Monthly amount of natural gas consumed (in MMBtu, scf, or therms) for each boiler (EUs: IP04 and IP05); *[40 CFR Part 60.48c(g)(1)]*

ii. Date and duration of operation of emergency generators for testing, maintenance, and nonemergency use (EUs: IP06 through IP11 and IP38); and

iii. Date and duration of operation of emergency generators for emergency use, including documentation justifying use during the emergency (EUs: IP06 through IP11 and IP38).

c. The permittee shall include, for all inspections, logs, visible emission checks, and testing required under monitoring, recordkeeping, and reporting sections, at least the date and time, the name of the person performing the action, the results or findings, and the type of corrective action taken (if required). *[AQR 12.5.2.6(d)]*

H. PLANET HOLLYWOOD

1. Emission Units

a. The stationary source activities at the Planet Hollywood covered by this Part 70 OP consist of the emission units and associated appurtenances summarized in Table III-H-1. *[AQR 12.5.2.3 and Part 70 OP (06/23/2021)]*

Table III-H-1: Summary of EUs – Planet Hollywood

EU	Type	Rating	Manufacturer	Model No.	Serial No.
PH07	Natural Gas Boiler	23.65 MMBtu/hr	Unilux	ZF2000W	2339
PH08	Natural Gas Boiler	23.65 MMBtu/hr	Unilux	ZF2000W	2340
PH09	Natural Gas Boiler	23.65 MMBtu/hr	Unilux	ZF2000W	2341

EU	Type	Rating	Manufacturer	Model No.	Serial No.
PH10	Genset – Emergency	1,750 kW	Spectrum	1750DS4	0628031
	Engine – Diesel DOM: 1999	2,550 hp	MTU/Detroit Diesel	T1637K16	5272000427
PH11	Genset – Emergency	1,750 kW	Spectrum	1750DS4	0628032
	Engine – Diesel DOM: 1999	2,550 hp	MTU/Detroit Diesel	T1637K16	5272000397
PH12	Genset – Emergency	1,750 kW	Spectrum	1750DS4	0628033
	Engine – Diesel DOM: 1999	2,550 hp	MTU/Detroit Diesel	T1637K16	5272000421
PH13	Genset – Emergency	1,750 kW	MTU	1750RXC6DT2	301122-1-1-1208
	Engine – Diesel DOM: 2008	2,561 hp	MTU/Detroit Diesel	T1238A36	5262003725
PH14	6-Cell Cooling Tower	33,360 gpm	Baltimore Aircoil Company	PCS50-2424-100-12P3	PC2429

Note: DOM: date of manufacture; gpm: gallons per minute; hp: horsepower; kW: kilowatt; MMBtu: millions of British thermal units.

2. Emission Limitations

a. The permittee shall limit the actual emissions from each emission unit to the PTE listed in Table III-H-2. *[Part 70 OP (06/23/2021)]*

Table III-H-2: PTE (tons per year) – Planet Hollywood

EU	Condition[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
PH07	8,760 hr/yr	0.78	0.78	3.78	7.67	0.06	0.56	0.20
PH08	8,760 hr/yr	0.78	0.78	3.78	7.67	0.06	0.56	0.20
PH09	8,760 hr/yr	0.78	0.78	3.78	7.67	0.06	0.56	0.20
PH10	500 hr/yr	0.45	0.45	15.30	3.51	0.01	0.45	0.01
PH11	500 hr/yr	0.45	0.45	15.30	3.51	0.01	0.45	0.01
PH12	500 hr/yr	0.45	0.45	15.30	3.51	0.01	0.45	0.01
PH13	500 hr/yr	0.21	0.21	6.40	3.68	0.01	0.34	0.01
PH14	8,760 hr/yr	8.58	8.58	0.00	0.00	0.00	0.00	0.00

[1]The quantities in this column are not intended as enforceable permit limits unless stated otherwise in this permit.

b. The permittee shall not allow actual emissions from the individual emission units to exceed the emission rates and emission concentrations listed in Table III-H-3. *[AQR 12.5.2.3 and Part 70 OP(06/23/2021)]*

Table III-H-3: Emissions – Planet Hollywood

EU	Rating	NO_x/CO (ppm)[1]	NO_x **(lbs/hr)**	CO **(lbs/hr)**
PH07	23.65 MMBtu/hr	NO_x 30/CO 100	0.86	1.75
PH08	23.65 MMBtu/hr	NO_x 30/CO 100	0.86	1.75
PH09	23.65 MMBtu/hr	NO_x 30/CO 100	0.86	1.75

[1]Corrected to 3% oxygen.

c. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant in excess of an average of 20% opacity for a period of more than six consecutive minutes. *[AQR 26.1]*

3. Production Limitations

a. The permittee shall limit the operation of each of the diesel-fired emergency generators for testing and maintenance purposes to 100 hours per year. The permittee may operate each of the emergency generators up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EUs: PH10 through PH12). *[40 CFR Part 63.6640(f)(i)(ii)]*

b. The permittee shall limit the operation of the diesel-fired emergency generator for testing and maintenance purposes to 100 hours per year. The permittee may operate the emergency generator up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EU: PH13). *[40 CFR Part 60.4211(f)]*

4. Control Requirements

Boilers/Water Heaters

a. The permittee shall combust only natural gas in all boilers/heaters. *[Part 70 OP (06/23/2021)]*

b. The permittee shall operate and maintain all boilers/heaters in accordance with the manufacturer's O&M manual for emissions-related components and good combustion practices. *[Part 70 OP (06/23/2021)]*

c. The permittee shall operate and maintain the boilers (EUs: PH07 through PH09) with burners that have a manufacturer's maximum emission concentration of 30 ppm NO_x, corrected to 3% oxygen. *[Part 70 OP (06/23/2021)]*

d. The permittee shall operate and maintain the boilers (EUs: PH07 through PH09) with burners that have a manufacturer's maximum emission concentration of 100 ppm CO, corrected to 3% oxygen. *[Part 70 OP (06/23/2021)]*

Diesel Generators

e. The permittee shall operate and maintain all diesel generators in accordance with the manufacturer's O&M manual for emissions-related components. *[Part 70 OP (06/23/2021)]*

f. The permittee shall operate each of the diesel engines with turbochargers and aftercoolers (EUs: PH10 through PH13). *[Part 70 OP (06/23/2021)]*

g. The permittee shall ensure that the diesel engine is in compliance with 40 CFR Part 60, Subpart IIII, by meeting of all of the following (EU: PH13): *[40 CFR Part 60.4206]*

i. operation of the engine according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer; and

ii. installation and configuration of the engine according to the manufacturer's specifications.

Cooling Towers

h. The permittee shall operate and maintain all cooling towers in accordance with the manufacturer's O&M manual for emissions-related components. No chromium-containing compounds shall be used for water treatment (EU: PH14). *[Part 70 OP (06/23/2021)]*

i. The permittee shall operate the cooling towers with drift eliminators that have a manufacturer's maximum drift rate of 0.005% (EU: PH14). *[Part 70 OP (06/23/2021)]*

j. The permittee shall limit the TDS content of each cooling tower's circulation water to 5,000 ppm (EU: PH14). *[Part 70 OP (06/23/2021)]*

Other

k. The permittee shall not cause, suffer, or allow any source to discharge air contaminants (or other materials) in quantities that will cause a nuisance, including excessive odors. *[AQR 40 & AQR 43]*

5. Monitoring

Boilers/Water Heaters

a. The permittee shall install and utilize nonresettable fuel meters such that the daily consumption of natural gas can be established for each applicable boiler (EUs: PH07 through PH09). *[AQR 12.5.2.6(d) and 40 CFR Part 60.48c(g)(2)]*

b. The permittee shall perform a burner efficiency test twice each calendar year, at least five months apart but no more than seven (EUs: PH07 through PH09). *[AQR 12.5.2.6(d)]*

c. The permittee shall conduct burner efficiency tests in accordance with the manufacturer's O&M manual and good combustion practices. Alternative methods may be used upon Control Officer approval (EUs: PH07 through PH09). *[AQR 12.5.2.6(d)]*

d. The permittee may perform a burner efficiency test once each calendar year if the actual hours of operation are less than 50. To exercise this option, the permittee must install an hour meter and begin keeping written records before the start of the calendar year (EUs: PH07 through PH09). *[AQR 12.5.2.6(d)]*

e. The permittee may replace one contemporaneously-required burner efficiency test with a performance test that has acceptable results (EUs: PH07 through PH09). *[AQR 12.5.2.6(d)]*

Diesel Generators

f. The permittee shall monitor operating hours for each applicable diesel engine utilizing nonresettable hour meters when operated for testing, maintenance, or during emergencies. (EUs: PH10 through PH13). *[AQR 12.5.2.6(d)]*

Visible Emissions

g. The responsible official shall sign and adhere to the *Visible Emissions Check Guidebook* and keep a copy of the signed guide on-site at all times. *[AQR 12.5.2.6(d)]*

h. The permittee shall conduct a visual emissions check at least quarterly on each diesel-fired emergency generator while in operation. *[AQR 12.5.2.6(d)]*

i. If no plume appears to exceed the opacity standard during the visible emissions check, the date, location, and results shall be recorded, along with the viewer's name. *[AQR 12.5.2.6(d)]*

j. If a plume appears to exceed the opacity standard, the permittee shall do one of the following: *[AQR 12.5.2.6(d)]*

   i. Immediately correct the perceived exceedance, then record the first and last name of the person who performed the emissions check, the date the check was performed, the unit(s) observed, and the results of the observation; or

   ii. Call a certified VEE reader to perform an EPA Method 9 evaluation.

      a. For sources required to have a certified reader on-site, the reader shall start Method 9 observations within 15 minutes of the initial observation. For all other sources, the reader shall start Method 9 observations within 30 minutes of the initial observation.

      b. If no opacity exceedance is observed, the certified VEE reader shall record the first and last name of the person who performed the VEE, the date the VEE was performed, the unit(s) evaluated, and the results. A Method 9 VEE form shall be completed for each emission unit that was initially perceived to have exceeded the opacity limit, and the record shall also indicate:

         (1) The cause of the perceived exceedance;

         (2) The color of the emissions; and

         (3) Whether the emissions were light or heavy.

      c. If an opacity exceedance is observed, the certified VEE reader shall take immediate action to correct the exceedance. The reader shall then record the first and last name of the person performing the VEE, the date the VEE was performed, the unit(s) evaluated, and the results. A Method 9 VEE form shall be completed for each reading identified, and the record shall also indicate:

         (1) The cause of the exceedance;

         (2) The color of the emissions;

(3) Whether the emissions were light or heavy;

(4) The duration of the emissions; and

(5) The corrective actions taken to resolve the exceedance.

k. Any scenario of visible emissions noncompliance can and may lead to enforcement action. *[AQR 12.5.2.6(d)]*

Cooling Towers

l. The permittee shall monitor the TDS in the cooling tower circulation water monthly. The permittee may use a conductivity meter or an equivalent method approved in advance by the Control Officer to determine TDS (EU: PH14). *[AQR 12.5.2.6(d)]*

6. Testing

a. Performance testing shall be the instrument for determining compliance with the emission limitations set forth in this permit for all boilers that have a heat input rating equal to or greater than 10.0 MMBtu/hr (EUs: PH07 through PH09). *[AQR 12.5.2.8(a) and DAQ's "Guidelines for Source Testing"]*

b. The permittee shall conduct performance tests on each boiler (EUs: PH07 through PH09) every five years, and no later than 90 days after the anniversary date of the last performance test. *[AQR 12.5.2.8(a) and DAQ's "Guidelines for Source Testing"]*

Table III-H-4: Performance Testing Protocol Requirements

Test Point	Pollutant	Method
Boiler Exhaust Outlet Stack	NO_x	EPA Method 7E
Boiler Exhaust Outlet Stack	CO	EPA Method 10 analyzer
Stack Gas Parameters	—	EPA Methods 1, 2, 3A, and 4

7. Recordkeeping

a. The permittee shall maintain records on site that include, at minimum, the following: *[AQR 12.5.2.6(d)]*

i. Dates and times when visible emissions checks and observations are made, and the corrective steps taken to bring opacity into compliance;

ii. Monthly TDS content of cooling tower circulation water;

iii. Log book of all inspections, maintenance, and repairs, as specified in this permit;

iv. Records of burner efficiency testing, as specified in this permit;

v. Results of performance testing; and

vi. Records of location changes for nonroad engines, if applicable.

b. The permittee shall maintain records on site and report the following semiannually: *[AQR 12.5.2.6(d)]*

i. Monthly amount of natural gas consumed (in MMBtu, scf, or therms) for each boiler (EUs: PH07 through PH09); *[40 CFR Part 60.48c(g)(1)]*

ii. Date and duration of operation of generators for emergency use, including documentation justifying use during the emergency (EUs: PH10 through PH13); and

iii. Date and duration of operation of emergency generators for testing, maintenance, and nonemergency use (EUs: PH10 through PH13).

c. The permittee shall include, for all inspections, logs, visible emission checks, and testing required under monitoring, recordkeeping, and reporting sections, at least the date and time, the name of the person performing the action, the results or findings, and the type of corrective action taken (if required). *[AQR 12.5.2.6(d)]*

I. LINQ COMPLEX – HIGH ROLLER

1. Emission Units

a. The stationary source activities at the LINQ Complex – High Roller covered by this Part 70 OP consist of the emission units and associated appurtenances summarized in Table III-I-1. *[AQR 12.5.2.3; Title V OP Significant Revision (05/29/13); and Title V OP (03/28/2016)]*

Table III-I-1: Summary of EU – LINQ Complex – High Roller

EU	Description	Rating	Make	Model No.	Serial No.
LI01	Natural Gas Boiler	5.0 MMBtu/hr	CAMUS	DNRH-5000-MSI	041215509
LI02	Natural Gas Boiler	5.0 MMBtu/hr	CAMUS	DNRH-5000-MSI	041215507
LI03	Natural Gas Boiler	5.0 MMBtu/hr	CAMUS	DNRH-5000-MSI	041215508
LI04	Natural Gas Boiler	5.0 MMBtu/hr	CAMUS	DNRH-5000-MSI	041215506
LI05	Natural Gas Boiler	5.0 MMBtu/hr	CAMUS	DNRH-5000-MSI	041215505
LI06	Emergency Generator DOM: 2012	2,000 kW	Caterpillar	SR4B-GD	G4Z00115
		3,634 hp		3516C	SBJ01461
LI07	Emergency Generator DOM: 2012	2,000 kW	Caterpillar	SR4B-GD	G4Z00116
		3,634 hp		3516C	SBJ01460
LI08	Cooling Tower, 2 cell	6,000 gpm	Marley	NC8413VAN2BGF	NC-10054867-B1&B2
LI09	Cooling Tower, 2 cell	6,000 gpm	Marley	NC8413VAN2BGF	NC-10054867-C1&C2
LI10	Cooling Tower, 2 cell	6,000 gpm	Marley	NC8413VAN2BGF	NC-10054867-A1&A2
LI11	Natural Gas Water Heater	0.150 MMBtu/hr	AO Smith	BTH-150-100	1304M002358

EU	Description	Rating	Make	Model No.	Serial No.
LI12	Emergency Engine DOM: 11/2012	180 kW 241 hp	Deutz	TCD 6.1 L6	11360110
LI13	Emergency Engine DOM: 11/2012	180 kW 241 hp	Deutz	TCD 6.1 L6	11353814

2. Emission Limitations

a. The permittee shall limit the actual emissions from each emission unit to the PTE listed in Table III-I-2. *[Title V OP Significant Revision (05/29/13); and Title V OP (03/28/2016)]*

Table III-I-2: PTE (tons per year) – LINQ Complex – High Roller

EU	Condition[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
LI01	8,760 hr/yr	0.16	0.16	0.24	0.81	0.01	0.12	0.04
LI02	8,760 hr/yr	0.16	0.16	0.24	0.81	0.01	0.12	0.04
LI03	8,760 hr/yr	0.16	0.16	0.24	0.81	0.01	0.12	0.04
LI04	8,760 hr/yr	0.16	0.16	0.24	0.81	0.01	0.12	0.04
LI05	8,760 hr/yr	0.16	0.16	0.24	0.81	0.01	0.12	0.04
LI06	500 hr/yr	0.06	0.06	10.80	0.58	0.01	0.22	0.03
LI07	500 hr/yr	0.06	0.06	10.80	0.58	0.01	0.22	0.03
LI08	8,760 hr/yr	1.55	1.55	0.00	0.00	0.00	0.00	0.00
LI09	8,760 hr/yr	1.55	1.55	0.00	0.00	0.00	0.00	0.00
LI10	8,760 hr/yr	1.55	1.55	0.00	0.00	0.00	0.00	0.00
LI11	8,760 hr/yr	0.01	0.01	0.01	0.02	0.01	0.01	0.01
LI12	500 hr/yr	0.01	0.01	0.20	0.35	0.01	0.02	0.01
LI13	500 hr/yr	0.01	0.01	0.20	0.35	0.01	0.02	0.01

[1]The quantities in this column are not intended as enforceable permit limits unless stated otherwise in this permit.

b. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant in excess of an average of 20% opacity for a period of more than six consecutive minutes. *[AQR 26.1]*

3. Production Limitations

a. The permittee shall limit the operation of each of the diesel-fired emergency generators for testing and maintenance purposes to 100 hours per year. The permittee may operate each emergency generator up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EUs: LI06, LI07, LI12, and LI13). *[40 CFR Part 60.4211(f)]*

4. Control Requirements

Boilers/Water Heaters

a. The permittee shall combust only natural gas in all boilers/heaters. *[Title V OP (05/29/2013)]*

b. The permittee shall operate and maintain all boilers/heaters in accordance with the manufacturer's O&M manual for emissions-related components and good combustion practices. *[Title V OP (05/29/2013)]*

c. The permittee shall operate and maintain the boilers (EUs: LI01 through LI05) with burners that have a manufacturer's maximum emission concentration of 9 ppm NO_x, corrected to 3% oxygen. *[Title V OP (05/29/2013)]*

d. The permittee shall operate and maintain the boilers (EUs: LI01 through LI05) with burners that have a manufacturer's maximum emission concentration of 50 ppm CO, corrected to 3% oxygen. *[Title V OP (05/29/2013)]*

Diesel Generators

e. The permittee shall operate and maintain all diesel generators in accordance with the manufacturer's O&M manual for emissions-related components. *[Title V OP (05/29/2013)]*

f. The permittee shall operate each of the diesel engines with turbochargers and aftercoolers (EUs: LI06, LI07, LI12, and LI13). *[Title V OP (05/29/2013)]*

g. The permittee shall ensure that the diesel engines are in compliance with 40 CFR Part 60, Subpart IIII, by meeting of all of the following (EUs: LI06, LI07, LI12, and LI13): *[40 CFR Part 60.4206]*

   i. operation of the engine according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer; and

   ii. installation and configuration of the engine according to the manufacturer's specifications.

Cooling Towers

h. The permittee shall operate and maintain all cooling towers in accordance with the manufacturer's O&M manual for emissions-related components. No chromium-containing compounds shall be used for water treatment. *[Title V OP (05/29/2013)]*

i. The permittee shall operate each of the cooling towers with drift eliminators that have a manufacturer's maximum drift rate of 0.005% (EUs: LI08 through LI10). *[Title V OP (05/29/2013)]*

j. The permittee shall limit the TDS content of each cooling tower's circulation water to 5,000 ppm. *[Title V OP (12/19/2019)]*

Other

k. The permittee shall not cause, suffer, or allow any source to discharge air contaminants (or other materials) in quantities that will cause a nuisance, including excessive odors. *[AQR 40 & AQR 43]*

5. Monitoring

Boilers/Water Heaters

a. The permittee shall perform a burner efficiency test once each calendar year (EUs: LI01 through LI05). *[AQR 12.5.2.6(d)]*

b. The permittee shall conduct burner efficiency tests in accordance with the manufacturer's O&M manual and good combustion practices. Alternative methods may be used upon Control Officer approval (EUs: LI01 through LI05). *[AQR 12.5.2.6(d)]*

c. The permittee shall not have to perform a burner efficiency test if the actual hours of operation are 0. To exercise this option, the permittee must install an hour meter and begin keeping written records before the start of the calendar year (EUs: LI01 through LI05). *[AQR 12.5.2.6(d)]*

d. The permittee may replace one contemporaneously-required burner efficiency test with a performance test that has acceptable results (EUs: LI01 through LI05). *[AQR 12.5.2.6(d)]*

Diesel Generators

e. The permittee shall monitor operating hours for each applicable diesel engine utilizing nonresettable hour meters when operated for testing, maintenance, or during emergencies. (EUs: LI06, LI07, LI12, and LI13). *[AQR 12.5.2.6(d)]*

Visible Emissions

f. The responsible official shall sign and adhere to the *Visible Emissions Check Guidebook* and keep a copy of the signed guide on-site at all times. *[AQR 12.5.2.6(d)]*

g. The permittee shall conduct a visual emissions check at least quarterly on each diesel-fired emergency generator while in operation. *[AQR 12.5.2.6(d)]*

h. If no plume appears to exceed the opacity standard during the visible emissions check, the date, location, and results shall be recorded, along with the viewer's name. *[AQR 12.5.2.6(d)]*

i. If a plume appears to exceed the opacity standard, the permittee shall do one of the following: *[AQR 12.5.2.6(d)]*

   i. Immediately correct the perceived exceedance, then record the first and last name of the person who performed the emissions check, the date the check was performed, the unit(s) observed, and the results of the observation; or

   ii. Call a certified VEE reader to perform an EPA Method 9 evaluation.

a. For sources required to have a certified reader on-site, the reader shall start Method 9 observations within 15 minutes of the initial observation. For all other sources, the reader shall start Method 9 observations within 30 minutes of the initial observation.

b. If no opacity exceedance is observed, the certified VEE reader shall record the first and last name of the person who performed the VEE, the date the VEE was performed, the unit(s) evaluated, and the results. A Method 9 VEE form shall be completed for each emission unit that was initially perceived to have exceeded the opacity limit, and the record shall also indicate:

(1) The cause of the perceived exceedance;

(2) The color of the emissions; and

(3) Whether the emissions were light or heavy.

c. If an opacity exceedance is observed, the certified VEE reader shall take immediate action to correct the exceedance. The reader shall then record the first and last name of the person performing the VEE, the date the VEE was performed, the unit(s) evaluated, and the results. A Method 9 VEE form shall be completed for each reading identified, and the record shall also indicate:

(1) The cause of the exceedance;

(2) The color of the emissions;

(3) Whether the emissions were light or heavy;

(4) The duration of the emissions; and

(5) The corrective actions taken to resolve the exceedance.

j. Any scenario of visible emissions noncompliance can and may lead to enforcement action. *[AQR 12.5.2.6(d)]*

Cooling Towers

k. The permittee shall monitor the TDS in the cooling tower circulation water monthly. The permittee may use a conductivity meter or an equivalent method approved in advance by the Control Officer to determine TDS (EUs: LI08 through LI10). *[AQR 12.5.2.6(d)]*

6. Testing

No performance testing requirements have been identified. *[AQR 12.5.2.8(a)]*

7. Recordkeeping

a. The permittee shall maintain records on site that include, at minimum, the following: *[AQR 12.5.2.6(d)]*

i. Dates and times when visible emissions checks and observations are made, and the corrective steps taken to bring opacity into compliance;

ii. Monthly TDS content of cooling tower circulation water;

iii. Log book of all inspections, maintenance, and repairs, as specified in this permit;

iv. Records of burner efficiency testing, as specified in this permit; and

v. Records of location changes for nonroad engines, if applicable.

b. The permittee shall maintain records on site and report the following semiannually: *[AQR 12.5.2.6(d)]*

i. Date and duration of operation of generators for emergency use, including documentation justifying use during the emergency (EUs: LI06, LI07, LI12, and LI13); and

ii. Date and duration of operation of emergency generators for testing, maintenance, and nonemergency use (EUs: LI06, LI07, LI12, and LI13).

c. The permittee shall include, for all inspections, logs, visible emission checks, and testing required under monitoring, recordkeeping, and reporting sections, at least the date and time, the name of the person performing the action, the results or findings, and the type of corrective action taken (if required). *[AQR 12.5.2.6(d)]*

J. BATTISTA'S

All the emission units at Battista's are insignificant and are listed in the TSD.

1. Emission Limitations

a. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant in excess of an average of 20% opacity for a period of more than six consecutive minutes. *[AQR 26.1]*

K. FORUM MEETING CENTER

1. Emission Units

a. The stationary source activities at the Forum Meeting Center covered by this Part 70 OP consist of the emission units and associated appurtenances summarized in Table III-K-1. *[AQR 12.5.2.3 and Title V OP (12/19/2019)]*

Table III-K-1: Summary of EUs – Forum Meeting Center

EU	Description	Rating	Make	Model No.	Serial No.
FMC01	Boiler	6.00 MMBtu/hr	Lochinvar	FBN6001	1847112615299
FMC02	Boiler	6.00 MMBtu/hr	Lochinvar	FBN6001	1847112615300
FMC03	Boiler	6.00 MMBtu/hr	Lochinvar	FBN6001	1847112615301
FMC04	Boiler	6.00 MMBtu/hr	Lochinvar	FBN6001	1847112615298
FMC05	Emergency	1,000 kW	Cummins	DQFAD-A061Y200	B190508151

	Generator DOM: 1/21/2019	1,490 hp		QST30	37277632
FMC06	Cooling Tower, 2-Cell	2,400 gpm/cell	Evapco	USS224-4P20	18-849683
FMC07	Cooling Tower, 2-Cell	2,400 gpm/cell	Evapco	USS224-4P20	18-849684

2. Emission Limitations

a. The permittee shall limit the actual emissions from each emission unit to the PTE listed in Table III-K-2. *[Title V OP (12/19/2019)]*

Table III-K-2: PTE (tons per year) – Forum Meeting Center

EU	Condition[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
FMC01	8,760 hr/yr	0.20	0.20	0.29	0.97	0.02	0.14	0.05
FMC02	8,760 hr/yr	0.20	0.20	0.29	0.97	0.02	0.14	0.05
FMC03	8,760 hr/yr	0.20	0.20	0.29	0.97	0.02	0.14	0.05
FMC04	8,760 hr/yr	0.20	0.20	0.29	0.97	0.02	0.14	0.05
FMC05	500 hr/yr	0.08	0.08	3.61	0.41	0.01	0.26	0.01
FMC06	8,760 hr/yr	0.25	0.25	0.00	0.00	0.00	0.00	0.00
FMC07	8,760 hr/yr	0.25	0.25	0.00	0.00	0.00	0.00	0.00

[1]The quantities in this column are not intended as enforceable permit limits unless stated otherwise in this permit.

b. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant in excess of an average of 20% opacity for a period of more than six consecutive minutes. *[AQR 26.1]*

3. Production Limitations

a. The permittee shall limit the operation of the diesel-fired emergency generator for testing and maintenance purposes to 100 hours per year. The permittee may operate the emergency generator up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EU: FMC05). *[40 CFR Part 60.4211(f)]*

4. Control Requirements

Boilers/Water Heaters

a. The permittee shall combust only natural gas in all boilers/heaters. *[Title V OP (12/19/2019)]*

b. The permittee shall operate and maintain all boilers/heaters in accordance with the manufacturer's O&M manual for emissions-related components and good combustion practices. *[Title V OP (12/19/2019)]*

c. The permittee shall operate and maintain the boilers (FMC01 through FMC04) with burners that have a manufacturer's maximum emission concentration of 9 ppm NO_x, corrected to 3% oxygen. *[Title V OP (12/19/2019)]*

d. The permittee shall operate and maintain the boilers (EUs: FMC01 through FMC04) with burners that have a manufacturer's maximum emission concentration of 50 ppm CO, corrected to 3% oxygen. *[Title V OP (12/19/2019)]*

Diesel Generator

e. The permittee shall operate and maintain the diesel generator in accordance with the manufacturer's O&M manual for emissions-related components. *[Title V OP (12/19/2019)]*

f. The permittee shall operate the diesel engine with a turbocharger and aftercooler (EU: FMC05). *[Title V OP (12/19/2019)]*

g. The permittee shall ensure that the diesel engine is in compliance with 40 CFR Part 60, Subpart IIII, by meeting of all of the following (EU: FMC05): *[40 CFR Part 60.4206]*

   i. operation of the engine according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer; and

   ii. installation and configuration of the engine according to the manufacturer's specifications.

Cooling Towers

h. The permittee shall operate and maintain all cooling towers in accordance with the manufacturer's O&M manual for emissions-related components. No chromium-containing compounds shall be used for water treatment. *[Title V OP (12/19/2019)]*

i. The permittee shall operate each of the cooling towers with drift eliminators that have a manufacturer's maximum drift rate of 0.001% (EUs: FMC06 and FMC07). *[Title V OP (12/19/2019)]*

j. The permittee shall limit the TDS content of each cooling tower's circulation water to 5,000 ppm. *[Title V OP (12/19/2019)]*

Other

k. The permittee shall not cause, suffer, or allow any source to discharge air contaminants (or other materials) in quantities that will cause a nuisance, including excessive odors. *[AQR 40 & AQR 43]*

5. Monitoring

Boilers/Water Heaters

a. The permittee shall perform a burner efficiency once each calendar year (EUs: FMC01 through FMC04). *[AQR 12.5.2.6(d)]*

b. The permittee shall conduct burner efficiency tests in accordance with the manufacturer's O&M manual and good combustion practices. Alternative methods may be used upon Control Officer approval (EUs: FMC01 through FMC04). *[AQR 12.5.2.6(d)]*

c. The permittee shall not have to perform a burner efficiency test if the actual hours of operation are 0. To exercise this option, the permittee must install an hour meter and begin keeping written records before the start of the calendar year (EUs: FMC01 through FMC04). *[AQR 12.5.2.6(d)]*

d. The permittee may replace one contemporaneously-required burner efficiency test with a performance test that has acceptable results (EUs: FMC01 through FMC04). *[AQR 12.5.2.6(d)]*

Diesel Generator

e. The permittee shall monitor operating hours for the diesel engine utilizing a nonresettable hour meter when operated for testing, maintenance, or during emergencies. (EU: FMC05). *[AQR 12.5.2.6(d)]*

Visible Emissions

f. The responsible official shall sign and adhere to the *Visible Emissions Check Guidebook* and keep a copy of the signed guide on-site at all times. *[AQR 12.5.2.6(d)]*

g. The permittee shall conduct a visual emissions check at least quarterly on each diesel-fired emergency generator while in operation. *[AQR 12.5.2.6(d)]*

h. If no plume appears to exceed the opacity standard during the visible emissions check, the date, location, and results shall be recorded, along with the viewer's name. *[AQR 12.5.2.6(d)]*

i. If a plume appears to exceed the opacity standard, the permittee shall do one of the following: *[AQR 12.5.2.6(d)]*

   i. Immediately correct the perceived exceedance, then record the first and last name of the person who performed the emissions check, the date the check was performed, the unit(s) observed, and the results of the observation; or

   ii. Call a certified VEE reader to perform an EPA Method 9 evaluation.

      a. For sources required to have a certified reader on-site, the reader shall start Method 9 observations within 15 minutes of the initial observation. For all other sources, the reader shall start Method 9 observations within 30 minutes of the initial observation.

      b. If no opacity exceedance is observed, the certified VEE reader shall record the first and last name of the person who performed the VEE, the date the VEE was performed, the unit(s) evaluated, and the results. A Method 9 VEE form shall be completed for each emission unit that was initially perceived to have exceeded the opacity limit, and the record shall also indicate:

         (1) The cause of the perceived exceedance;

         (2) The color of the emissions; and

         (3) Whether the emissions were light or heavy.

c. If an opacity exceedance is observed, the certified VEE reader shall take immediate action to correct the exceedance. The reader shall then record the first and last name of the person performing the VEE, the date the VEE was performed, the unit(s) evaluated, and the results. A Method 9 VEE form shall be completed for each reading identified, and the record shall also indicate:

(1) The cause of the exceedance;

(2) The color of the emissions;

(3) Whether the emissions were light or heavy;

(4) The duration of the emissions; and

(5) The corrective actions taken to resolve the exceedance.

j. Any scenario of visible emissions noncompliance can and may lead to enforcement action. *[AQR 12.5.2.6(d)]*

Cooling Towers

k. The permittee shall monitor the TDS in the cooling tower circulation water monthly. The permittee may use a conductivity meter or an equivalent method approved in advance by the Control Officer to determine TDS (EUs: FMC06 and FMC07). *[AQR 12.5.2.6(d)]*

6. Testing

No performance testing requirements have been identified. *[AQR 12.5.2.8(a)]*

7. Recordkeeping

a. The permittee shall maintain records on site that include, at a minimum, the following: *[AQR 12.5.2.6(d)]*

i. Dates and times when visible emissions checks and observations are made, and the corrective steps taken to bring opacity into compliance;

ii. Monthly TDS content of cooling tower circulation water;

iii. Log book of all inspections, maintenance, and repairs, as specified in this permit;

iv. Records of burner efficiency testing, as specified in this permit; and

v. Records of location changes for nonroad engines, if applicable.

b. The permittee shall maintain records on site and report the following semiannually: *[AQR 12.5.2.6(d)]*

i. Date and duration of operation of the generator for emergency use, including documentation justifying use during the emergency (EU: FMC05); and

ii. Date and duration of operation of the emergency generator for testing, maintenance, and nonemergency use (EU: FMC05).

c. The permittee shall include, for all inspections, logs, visible emission checks, and testing required under monitoring, recordkeeping, and reporting sections, at least the date and time, the name of the person performing the action, the results or findings, and the type of corrective action taken (if required). *[AQR 12.5.2.6(d)]*

IV. MITIGATION

The source has no federal offset requirements. *[AQR 12.7]*

V. NONROAD ENGINES

Pursuant to 40 CFR Part 1068.30, nonroad engines that are portable or transportable (i.e., not used on self-propelled equipment) shall not remain at a location for more than 12 consecutive months; otherwise, the engine will constitute a stationary reciprocating internal combustion engine (RICE) and be subject to the applicable requirements of 40 CFR Part 63, Subpart ZZZZ; 40 CFR Part 60, Subpart IIII; and/or 40 CFR Part 60, Subpart JJJJ. Stationary RICE shall be permitted as emission units upon commencing operation at this stationary source. Records of location changes for portable or transportable nonroad engines shall be maintained, and shall be made available to the Control Officer upon request. These records are not required for engines owned and operated by a contractor for maintenance and construction activities, as long as records are maintained demonstrating that such work took place at the stationary source for periods of less than 12 consecutive months.

Nonroad engines used on self-propelled equipment do not have this 12-month limitation or the associated recordkeeping requirements.

VI. OTHER REQUIREMENTS

1. The permittee shall not use, sell, or offer for sale any fluid as a substitute material for any motor vehicle, residential, commercial, or industrial air conditioning system, refrigerator freezer unit, or other cooling or heating device designated to use a chlorofluorocarbon (CFC) or hydrochlorofluorocarbon (HCFC) compound as a working fluid, unless such fluid has been approved for sale in such use by the Administrator. The permittee shall keep record of all paperwork relevant to the applicable requirements of 40 CFR Part 82 on site. *[40 CFR Part 82]*

2. Caesars shall complete the development and implementation of its Environmental Management Portal (EMP) to assure Caesars future compliance with the requirements of this Operating Permit. The EMP shall be utilized for: *[Hearing Officer's Order (03/28/2019)]*

   a. Monitoring and recording periodic inspections;

   b. Training personnel on regulatory requirements;

   c. Tracking of permitted EUs, regulatory requirements and deadlines, testing deadlines, and permit expiration dates; and

   d. Notifying personnel of upcoming regulatory requirements, including but not limited to testing and reporting deadlines and recordkeeping requirements.

3. The EMP must be in use at all times for recordkeeping, tracking, and notification purposes. *[Hearing Officer's Order (03/28/2019)]*

4. Caesars shall have adopted written procedures for the use of the EMP application and shall commence annual training of all appropriate staff from each of the Facilities. Caesars will maintain records of the attendees, topics addressed, and dates of training. *[Hearing Officer's Order (03/28/2019)]*

VII. PERMIT SHIELD

1. Compliance with the terms contained in this permit shall be deemed compliance with the following applicable requirements in effect on the date of permit issuance:

Table VII-1: Applicable Requirements Related to Permit Shield

Applicable Regulation	Title
40 CFR Part 60, Subpart Dc	Standards of Performance for New Stationary Sources (NSPS) – Small Industrial-Commercial-Institutional Steam Generating Units
40 CFR Part 60, Subpart IIII	Standards of Performance for New Stationary Sources (NSPS) – Stationary Compression Ignition (CI) Internal Combustion Engines (ICE)
40 CFR Part 63, Subpart ZZZZ	National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines
40 CFR Part 63, Subpart CCCCCC	National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities

VIII. ATTACHMENTS

A. APPLICABLE REGULATIONS

1. Nevada Revised Statutes, Chapter 445B.
2. Applicable AQR sections, as listed in Table VIII-A-1.

Table VIII-A-1: Requirements Specifically Identified As Applicable—Local

Citation	Title
AQR Section 0	Definitions
AQR Section 4	Control Officer
AQR Section 12.0	General application requirements for construction of new and modified sources of air pollution
AQR Section 12.2	Permit Requirements for Major Sources in Attainment Areas
AQR Section 12.3	Permit Requirements for Major Sources in Nonattainment Areas
AQR Section 12.4	Authority to Construct Application and Permit Requirements for Part 70 Sources
AQR Section 12.5	Part 70 Operating Permit Requirements
AQR Section 12.13	Posting of Permit
AQR Section 13.2(b)(82) Subpart ZZZZ	NESHAP – Stationary Reciprocating Internal Combustion Engines
AQR Section 13.2.(b)(106) Subpart CCCCCC	NESHAP – Gasoline Dispensing Facilities

Citation	Title
AQR Section 14.1(b)1, Subpart A	NSPS – General Provisions
AQR Section 14.1(b)(5)	NSPS – Standards of Performance for Small Industrial – Commercial – Institutional Steam Generating Units (Subpart Dc)
AQR Section 14.1(b)(80)	NSPS – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (Subpart IIII)
AQR Section 18	Permit and Technical Service Fees
AQR Section 25	Affirmative Defense for Excess Emissions Due to Malfunctions, Startup, and Shutdown
AQR Section 26.1	Emissions of Visible Air Contaminants
AQR Section 28	Fuel Burning Equipment
AQR Section 40	Prohibition of Nuisance Conditions
AQR Section 41.1	Fugitive Dust
AQR Section 42	Open Burning
AQR Section 43	Odors in the Ambient Air
AQR Section 70.4	Emergency Procedures
AQR Section 80	Circumvention

3. Clean Air Act, as amended (authority: 42 U.S.C. § 7401, et seq.)
4. Applicable 40 CFR subsections, as listed in Table VIII-A-2.

Table VIII-A-2. Requirements Specifically Identified As Applicable—Federal

Citation	Title
40 CFR Part 52.21	Prevention of Significant Deterioration (PSD)
40 CFR Part 52.1470	SIP Rules
40 CFR Part 60, Subpart A	Standards of Performance for New Stationary Sources – General Provisions
40 CFR Part 60, Subpart Dc	Standards of Performance for New Stationary Sources – Small Industrial-Commercial-Institutional Steam Generating Units
40 CFR Part 60	Appendix A, Method 9 or equivalent, (Opacity)
40 CFR Part 60, Subpart IIII	Standards of Performance for New Stationary Sources – Stationary Compression Ignition (CI) Internal Combustion Engines (ICE)
43 CFR Part 63, Subpart ZZZZ	NESHAP for Stationary Reciprocating Internal Combustion Engines
40 CFR Part 63, Subpart CCCCCC	NESHAP for Gasoline Dispensing Facilities
40 CFR Part 70	Federally Mandated Operating Permits
40 CFR Part 82	Protection of Stratospheric Ozone

Appendix B
RACT Analysis – Hurst and Burnham Boilers
Emission Units CP01, CP02, CP03, CP04 and CP05

APPENDIX B

RACT Analysis

Hurst and Burnham Boilers, Emission Units CP01, CP02, CP03, CP04 and CP05

Appendix B
Table of Contents

Attachments

1.0 General

This appendix summarizes the Reasonably Available Control Technology (RACT) Analysis performed for the Hurst and Burnham boilers, Emission Units (EUs) CP01 - CP05, located at Caesars Entertainment, Inc. (Caesars), Caesars Palace. The basic steps for this analysis are as follows:

- Identification of existing equipment and baseline emissions
- Identification of available control options
- Elimination of technically infeasible control options
- Determination of the cost effectiveness of control options
- Evaluation of the benefits and disadvantages (environmental, energy and economic) associated with the technically feasible control options
- Identification of RACT control technology including emission limitations, monitoring, testing, recordkeeping and reporting requirements

Controls for oxides of nitrogen (NO_X) are evaluated in this appendix.

2.0 NO_X RACT Assessment

2.1 Equipment Description and Limitations

EUs CP01 - CP05 utilize natural gas as the fuel supply. There are no limitations on hours of operation or fuel consumption. NO_X emissions are limited to 29 ppm @ 3% O_2 (1.24 lb/hr) for EUs CP01 and CP02 and 30 ppm @ 3% O_2 (1.23 lb/hr) for EUs CP03, CP04 and CP05. All five emissions units are similar (3-pass, fire-tube type and rated at 800 bhp). The only difference between the emission units is the manufacturer and maximum heat input rating of the burners, however, the difference in maximum heat input ratings between the Hurst and Burnham boilers is small. For these reasons, this evaluation is being performed for all five emission units concurrently.

2.2 Baseline Emissions

As noted in Section 3 of the report, baseline emissions can be set equivalent to actual emissions if actual emissions for the three previous consecutive years are 70% or less of the source's or individual emission unit's potential emissions. Caesars meets this criterion on both a facility-wide basis and individual emissions unit basis. Table 1 below summarizes the baseline NO_X emissions for each emission unit.

Table 1 - Baseline Emissions

Emission Unit	NO_X Emissions[1] (tons)
CP01	2.23
CP02	2.74
CP03	2.35
CP04	1.08
CP05	2.49

Notes: [1] Maximum annual emissions for 2019 - 2021.

2.3 Identification and Technical Feasibility of NO_X Control Options

2.3.1. Identification of Available Controls

A review of the most recent (5 years) determinations contained in the U.S. EPA RACT/BACT/LAER Clearinghouse was conducted to identify any recent RACT determinations for boilers of the same or comparable size. The database did not contain any RACT determinations for this time period. In addition, various U.S. EPA control technology reports were reviewed and the current contractor responsible for servicing the Caesars' boilers was consulted to identify potential controls. Based on the information obtained, the proposed NO_X control technologies for EUs CP01-CP05 are summarized in Table 2.

Table 2 – Available NO_X Control Technology Methods for EUs CP01 - CP05

Control Equipment	NO_X Reduction Potential (%)	Range of Application	Commercial Availability/ R&D Status
Flue Gas Recirculation (FGR)	30-60	FGR requires physical space around the boiler that is not always available	Commercially available with certain boilers
Ultra-Low NOx Burner	30-70 (9 ppm)	Burner changeout is normally an option for any boiler.	Commercially available
Selective Catalytic Reduction (SCR)	75-90	Limited range of application and normally not with boiler exhaust profiles	Commercially available
Selective Non-Catalytic Reduction (SNCR)	75-90	Limited range of application and normally not with boiler exhaust profiles	Commercially available

The technical feasibility of each control option will next be evaluated.

2.3.2. Flue Gas Recirculation (FGR)

FGR involves the recirculation of a portion of the flue gas to the burners. It reduces NO_X emissions by two mechanisms. First, the recirculated gas acts as a dilutant to reduce combustion temperatures, thus suppressing the thermal NO_X mechanism. Second, FGR lowers the oxygen concentration in the primary flame zone. The portion recycled is up to 25% to 30% and it can be implemented on most modern design types. It may not be feasible to retrofit this technology on all existing boiler types or in places with spacing limitations. According to the Caesars boiler maintenance contractor, the existing boilers with Riello burners cannot be retrofitted with FGR due to the configuration of the components for the combustion air supply for the burners. Therefore, an FGR retrofit is not technically feasible for these boilers. An FGR retrofit in conjunction with burner replacement is potentially feasible but since it would not represent a significant improvement in the amount of control possible when compared to retrofitting an ultra-low NO_X burner alone, this control option is not considered to be an alternative control strategy to an ultra-low NO_X burner.

2.3.3. Ultra-Low NO_X Burner

Low NO_X burners reduce NO_X by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame, which suppresses thermal NO_X formation. The two most common types of low NO_X burners being applied to natural gas boilers are staged air burners and staged fuel burners, or a combination thereof. The existing Riello burners associated with all five boilers are low NO_x design already and cannot be modified to increase NO_x reduction to the level of an ultra-low burner capability so it would be necessary to replace each burner with an ultra-low NO_X burner. This is technically feasible and would be capable of reducing the NO_X concentration in the boiler exhaust to 9 ppm @ 3% O_2. Emissions of CO would necessarily increase, however.

2.3.4. Selective Catalytic Reduction (SCR)

SCR involves the injection of ammonia in the boiler exhaust gases in the presence of a catalyst. The catalyst allows the ammonia to reduce NO_X levels at lower exhaust temperatures than selective non-catalytic reduction (SNCR). Unlike SNCR, where the exhaust gases must be approximately 1400-1600°F, SCR can be utilized where exhaust gases are between 500° F and 1200° F, depending on the catalyst used. SCR can result in NO_X reductions up to 75%. Since all of the boilers reviewed in this analysis generate exhaust temperatures of less than 400° F, an SCR system is not a technically feasible option for this application.

2.3.5. Selective Non-Catalytic Reduction (SNCR)

SNCR involves the injection of a NO_X reducing agent, such as ammonia or urea, in the boiler exhaust gases at a temperature of approximately 1400-1600°F. The ammonia or urea breaks down the NO_X in the exhaust gases into water and atmospheric nitrogen. SNCR reduces NO_X up to 50%. As was the case with SCR control, the boiler exhaust temperatures are far too low to implement SNCR as a viable control technology. The 400 ° F boiler exhaust makes an SNCR system not technically feasible for this application.

2.3.6. Technological Feasibility Summary

Table 3 summarizes the technological feasibility evaluations of the identified control options.

Table 3 – NO_X Control Technology Methods for EU CP01 - CP05

Control Equipment	Technically Feasible?	Uncontrolled NO_X Emissions (tons/yr)	NO_X Controlled Emission Rate (tons/yr)	NO_X removed (tons/yr)
FGR	No	n/a	n/a	n/a
Ultra-Low NO_x Burner	Yes	1.08 - 2.74	0.32 - 0.82	0.76 - 1.92
SCR	No	n/a	n/a	n/a
SNCR	No	n/a	n/a	n/a

Based on the information presented in Table 3, Caesars will evaluate the cost of an ultra-low NO_X burner rated at 9 ppm.

2.4 Cost of NO_X Control Options

For each technically feasible method of control, a total annualized equipment cost and an annual operating cost has been calculated. The calculation of the capital cost recovery factor used to estimate the annualized equipment cost assumes an interest rate of 6% and equipment life of 10 years. The individual cost calculations for each EU are included in Attachment B-1. The capital cost is based on an actual quote from an equipment vendor, a copy of which is included with Attachment B-1. The calculated costs are summarized in Table 4.

Table 4 – Cost of NO_X Control Options for EUs CP01 - CP05

Method of Control	Annualized Cost ($/yr)	Estimated NO_X Removal (tons/yr)	Cost Effectiveness ($/ton removed)
Ultra-Low NO_X Burner (CP01)	$32,337	1.56	$20,715
Ultra-Low NO_X Burner (CP02)	$32,337	1.92	$16,860
Ultra-Low NO_X Burner (CP03)	$32,337	1.65	$19,657
Ultra-Low NO_X Burner (CP04)	$32,337	0.76	$42,773
Ultra-Low NO_X Burner (CP05)	$32,337	1.74	$18,552

2.5 Environmental, Energy & Economic Considerations

2.5.1. Environmental Impacts

As shown in Table 4, there is only a minimal potential reduction in NO_X emissions associated with the installation of ultra-low NO_X burners. Installation of ultra-low NO_X burners would result in an increase in carbon monoxide (CO) emissions and necessitate a revision to the current permit. Potential CO emissions would increase by a factor of two for each boiler retrofitted with an ultra-low NO_X burner.

2.5.2. Energy Impacts

It is anticipated that only minimal adverse energy impacts would be associated with an ultra-low NO_X burner technology since there would be a minimal decrease in burner efficiency.

2.5.3. Economic Impacts

The economic impacts analysis is based on the cost effectiveness of each technology in terms of the cost per ton of removed pollutant as evaluated in Section 2.4. A maximum cost effectiveness threshold for NO_X RACT has not been established by DAQ. In 1994, the U.S. EPA recommended a maximum of $1,300 per ton to represent RACT at that time. Based on the increase in the Chemical Engineering Plant Cost Index (CEPCI) between then and now, this equates to approximately $3,000 per ton for the present. The U.S. EPA, in its approval of certain State Implementation Plan revisions for Pennsylvania (85 FR 65706) noted that Pennsylvania's proposed maximum of $2,800 per ton was low compared to other states but approved it. Maximum thresholds for other jurisdictions were presented in the notice as follows:

- Wisconsin, $2,500 per ton NO_X
- Illinois, $2,500—$3,000 per ton NO_X

- Maryland, \$3,500—\$5,000 per ton NO_X
- Ohio, \$5,000 per ton NO_X
- New York, \$5,000—\$5,500 per ton NO_X

For the purpose of this analysis, even if the maximum value of \$5,500 from above is deemed appropriate in Clark County, the cost of control for each individual boiler significantly exceeds this value. Table 4 presents the cost effectiveness of the viable control option upgrades. They exceed the most stringent RACT thresholds several times over.

3.0 NO_X RACT Determination

After eliminating technically infeasible options and evaluating the remaining technologies for environmental, energy, and economic impacts, it is evident that emission units CP01-CP05 can be considered to comply with RACT with existing emission limitations, monitoring, testing and recordkeeping. Performance tests indicate the current emission limits are achieved.

ATTACHMENT B-1

Cost Effectiveness Calculation

Emission Unit/Control Technology

Emission Unit	CP01
Emission Unit Description	Hurst Boiler
Control Technology	Ultra-Low NO_X Burner
Baseline Emission Rate[1] (tons/year)	2.23
Emission Reduction[2] (%)	70%
Controlled Emissions (tons/year)	0.67

Annualized Capital Costs

Initial Capital Investment[3]	$235,000
Direct & Indirect Costs[4]	$3,000
Total Capital Investment	$238,000
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$32,337

Annual Operating Costs

No additional annual operating cost identified

Total Annualized Cost	$32,337

Cost Effectiveness

Emissions Reduction (tons/year)	1.56
Cost Effectiveness of NO_X Reduction ($/ton)	$20,715

Notes:

[1] Maximum actual emissions for 2019 - 2021.

[2] NO_X emissions reduced from 29 ppm to 9 ppm.

[3] Cost based on vendor estimate includes installation and startup.

[4] Performance testing.

Cost Effectiveness Calculation

Emission Unit/Control Technology	
Emission Unit	CP02
Emission Unit Description	Hurst Boiler
Control Technology	Ultra-Low NO_X Burner
Baseline Emission Rate[1] (tons/year)	2.74
Emission Reduction[2] (%)	70%
Controlled Emissions (tons/year)	0.82
Annualized Capital Costs	
Initial Capital Investment[3]	$235,000
Direct & Indirect Costs[4]	$3,000
Total Capital Investment	$238,000
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$32,337
Annual Operating Costs	
No additional annual operating cost identified	
Total Annualized Cost	$32,337
Cost Effectiveness	
Emissions Reduction (tons/year)	1.92
Cost Effectiveness of NO_X Reduction ($/ton)	$16,860

Notes:

[1] Maximum actual emissions for 2019 - 2021.

[2] NO_X emissions reduced from 29 ppm to 9 ppm.

[3] Cost based on vendor estimate includes installation and startup.

[4] Performance testing.

Cost Effectiveness Calculation

Emission Unit/Control Technology

Emission Unit	CP03
Emission Unit Description	Burnham Boiler
Control Technology	Ultra-Low NO_X Burner
Baseline Emission Rate[1] (tons/year)	2.35
Emission Reduction[2] (%)	70%
Controlled Emissions (tons/year)	0.71

Annualized Capital Costs

Initial Capital Investment[3]	$235,000
Direct & Indirect Costs[4]	$3,000
Total Capital Investment	$238,000
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$32,337

Annual Operating Costs

No additional annual operating cost identified

Total Annualized Cost	$32,337

Cost Effectiveness

Emissions Reduction (tons/year)	1.65
Cost Effectiveness of NO_X Reduction ($/ton)	$19,657

Notes:

[1] Maximum actual emissions for 2019 - 2021.

[2] NO_X emissions reduced from 29 ppm to 9 ppm.

[3] Cost based on vendor estimate includes installation and startup.

[4] Performance testing.

Cost Effectiveness Calculation

Emission Unit/Control Technology	
Emission Unit	CP04
Emission Unit Description	Burnham Boiler
Control Technology	Ultra-Low NO_X Burner
Baseline Emission Rate[1] (tons/year)	1.08
Emission Reduction[2] (%)	70%
Controlled Emissions (tons/year)	0.32
Annualized Capital Costs	
Initial Capital Investment[3]	$235,000
Direct & Indirect Costs[4]	$3,000
Total Capital Investment	$238,000
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$32,337
Annual Operating Costs	
No additional annual operating cost identified	
Total Annualized Cost	$32,337
Cost Effectiveness	
Emissions Reduction (tons/year)	0.76
Cost Effectiveness of NO_X Reduction ($/ton)	$42,773

Notes:

[1] Maximum actual emissions for 2019 - 2021.

[2] NO_X emissions reduced from 29 ppm to 9 ppm.

[3] Cost based on vendor estimate includes installation and startup.

[4] Performance testing.

Cost Effectiveness Calculation

Emission Unit/Control Technology

Emission Unit	CP05
Emission Unit Description	Burnham Boiler
Control Technology	Ultra-Low NO_X Burner
Baseline Emission Rate[1] (tons/year)	2.49
Emission Reduction[2] (%)	70%
Controlled Emissions (tons/year)	0.75

Annualized Capital Costs

Initial Capital Investment[3]	$235,000
Direct & Indirect Costs[4]	$3,000
Total Capital Investment	$238,000
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$32,337

Annual Operating Costs

No additional annual operating cost identified

Total Annualized Cost	$32,337

Cost Effectiveness

Emissions Reduction (tons/year)	1.74
Cost Effectiveness of NO_X Reduction ($/ton)	$18,552

Notes:

[1] Maximum actual emissions for 2019 - 2021.

[2] NO_X emissions reduced from 29 ppm to 9 ppm.

[3] Cost based on vendor estimate includes installation and startup.

[4] Performance testing.

PYRO COMBUSTION & CONTROLS INC.

Company:	Broadbent	Date	Estimate No
Attention:	Russ Harms	9/13/2022	221614
Phone:			
Fax:			

Pyro Combustion & Controls, Inc, is pleased to offer, for your consideration the following:

REFERENCE REPLACE BURNER ON 1(ONE) BOILER IN CENTRAL PLANT

* 1(one)- Powerflame 9PPM Nox 50ppm CO Burner
* Siemens's LMV linkageless with VFD
* 1(one)- refractory ring
* Remove existing burner
* Install new refractory ring
* Mount burner to boiler
* Wire to existing controls
* Start-up and check safety controls for proper operation

Sales Tax - Clark County

Lead Time:

Our price, including labor, materials, applicable taxes and freight................ $234,863.00

Thank you for your consideration, we look forward to receiving your response.
Terms: Orders in excess of $25,000 will require payment of 25% Down, 50% upon Shipping and 25% on Completion.
If payment is made via credit card a 4.5% non-cash transaction fee will apply on all orders over $5,000.00.

Joe Harris

If this quotation meets with your approval please sign, date and indicate its purchase order number below and fax back to (702) 385-7976 or email joseph@pyrocombustion.com

Quote Valid for 30 Days

Acceptance: ___________________________________ Date: ___________________

Purchase Order # ______________________________

2969 S Highland Dr - Las Vegas NV 89109 - Lic#57902
phone: 702-384-7976 - fax: 702-385-7976 - www.pyrocombustion.com

BURNER SCOPE

Date: 09/12/2022

To: PYRO COMBUSTION AND CONTROLS

From: KEVIN STEPP
ENERGY PRODUCTS

Burner Information:

Burner: NVC13-G-30 9-12 PPM
Mode: MOD ODP   Approval: NFPA
Other: CSD-1
Gas Rate: 33600   Oil Rate:
Fuel Type: NAT GAS
Supply Voltage: 460/3/60

Boiler Information:

HURST AND BURNHAM BOILERS
Model: S4-G-400-150 3P-800
Type: SCOTCH-MARINE BOILER
Gas Pressure: Min: - Max: 5.00 (PSI)
Furnace Press: 1.93
Job Name: CAESARS K-PAK

We are pleased to quote the following equipment:

Equipment

QTY	DESCRIPTION
1	40.00 HP HIGH EFFICIENCY 3 PH BLOWER MOTOR
1	LMV52.440B1 FLAME SAFEGUARD AND PARALLEL POSITIONING CONTROL W/AZL UV
1	ALARM BUZZER
1	GAS PILOT WITH 6KV IGNITION TRANSFORMER
1	PREPURGE: PROVEN OPEN DAMPER PREPURGE SEQUENCE
1	MAIN GAS STRAINER
1	PILOT GAS STRAINER
1	AUXILIARY PILOT SOLENOID VALVE
1	PILOT N. O. VENT VALVE
1	LOCKING SHUTOFF COCK FOR PILOT N.O.V.V. AND MAIN N.O.V.V.
1	PREMIX SURFACE STABILIZED COMBUSTION HEAD
1	BLACK CONDUIT STD
1	Gas Train: SDC30-MOD-AXA-H
1	THREE GAS PRESSURE GAUGES
1	3.00" LUBRICATED LEAK TEST SHUTOFF
1	LGP-G 1-20 IN. LOW GAS PRESSURE SWITCH
1	SKP15.011U1 MOTORIZED VALVE BODY W/ PROOF OF CLOSURE
1	3.00" VGD40.08U DUAL VALVE BODY MAIN GAS SHUTOFF
1	1.25" NORMALLY OPEN VENT VALVE
1	HGP-G 2-20 IN. MANUAL RESET HIGH GAS PRESSURE SWITCH
1	3.00" MAIN GAS BALL VALVE SHUTOFF

Additional Equipment

QTY	TYPE	ID	DESCRIPTION
1	A	11.006	CSD-1 CODE GAS ADDERS 3.00 INCH GAS TRAIN

1	E	3.190	24 X 34 CONTROL PANEL
1	E	5.110	500VA STEPDOWN 208/230/460 PRIMARY 120 SECONDARY W/PRIMARY AND SECONDARY FUSES
1	E	7.300	AUTO RESET ALARM SILENCING SYSTEM
3	E	8.300	RED INDICATOR LIGHT 120V. - LW, FF, PFF
1	E	9.010	3PDT RELAY --- SPECIFY RELAY FUNCTION --- - CONTACT FOR BREAK GLASS STATION
3	E	9.010	3PDT RELAY --- SPECIFY RELAY FUNCTION --- - LW, FF, PFF SOUND ALARM CONDITIONS
2	E	10.404	CSD-1 ELECTRICAL TERMINALS FOR EMERGENCY DISCONNECT BY OTHERS
1	E	15.281	3 POLE 100 AMP FUSE BLOCK TOUCH SAFE 25 HP 208 50 HP 480 - SINGLE POINT
1	E	15.288	FUSES 3 POLE 100 AMP 25 HP AT 208 - 40 HP 480V FAST ACT REQUIRED FOR VFD
1	E	16.000	HOUR RUNNING METER 635G,99,999.9 HOURS
-2	G	3.460	3" ADDITIONAL BALL VALVE
2	G	3.485	3" ADDITIONAL BALL VALVE, CSD-1 COCKS
2	G	19.110	1/4" BALL VALVE LEAK TEST/GAUGE COCK
1	M	3.610	40 HP HIGH EFF. BLOWER MOTOR WITH TEFC ILO STD
1	P	94.220	LMV OPT. SENSORS 4-20 mA PRESS. 0-200 PSI - 502685
1	V	50.026	YASKAWA-VF DRIVES 40 HP 480 V GA80U4023ABM(60 amps) MOUNTING BRACKET
1	V	60.005	3 CONTACTOR BYPASS (5), 577556, 576150 x 2, 140720 460/3/60 40 HP OR LESS

Pricing summary for quote: 090822-055MJS

Estimated Weight: 3200

Lead Time: 16 TO 20 WKS

1 ALL PRICES QUOTED ARE IN USD FOB PARSONS, KANSAS UNLESS OTHERWISE STATED.

2 ALL PRICES QUOTED ARE IN USD EX-WORKS PARSONS, KANSAS UNLESS OTHERWISE STATED.

3 ALL BOILER CONTROLS AND TRIM ARE TO BE SUPPLIED BY OTHERS.

4 ANY ITEMS WHICH ARE REQUIRED BUT ARE NOT SPECIFICALLY LISTED ARE NOT INCLUDED IN THE QUOTED PRICE AND ARE ASSUMED TO BE SUPPLIED BY OTHERS.

5 CLERICAL ERRORS OR OMISSIONS ARE SUBJECT TO CORRECTION

6 CURRENT LEAD TIME ESTIMATES ARE BASED ON ENGINEERING AND PRODUCTION LEAD TIMES. THIS LEAD TIME DOES NOT TAKE INOT ACCOUNT ANY SUPPLIER/DELIVERY ISSUES OUTSIDE OF POWER FLAME CONTROL. IF WE FIND AN ISSUE WITH THIS INITIAL LEAD TIME ESTIMATE WE WILL INFORM YOU IN A TIMELY MANNER. A NEW ESTIMATED DELIVERY DATE WILL BE PROVIDED ALONG WITH ANY KNOWN ALTERNATE PARTS TO MITIGATE EXTENDED LEAD TIMES. ALTERNATE PARTS MAY OR MAY NOT INCLUDE A COST ADDER.

7 POWER FLAME WARRANTY IS 15 MONTHS PAST THE DATE OF DELIVERY FOR PARTS ONLY.
POWER FLAME TAKES EXCEPTION TO ANY BLANKET REFERENCE OF STATE AND OR LOCAL CODE THAT IS UNKNOWN TO POWER FLAME AND SUBJECT TO CHANGE

8 ALL PRICING VALID FOR 30 DAYS

9 NO OTHER OPTIONS REQUESTED.

10 FREIGHT IS NOT INCLUDED IN THIS PRICE

11 MILESTONE PAYMENT TERMS ARE:
30% DUE AT RELEASE TO MANUFACTURING
30% DUE PRIOR TO SHIPMENT
40% DUE 30 DAYS AFTER SHIPMENT

POWER FLAME INCORPORATED
GENERAL TERMS AND CONDITIONS
FOR EQUIPMENT AND ANCILLARY SERVICES

1. GENERAL: Seller requires that its dealers pass this agreement on to the end user. As used herein, "Equipment" is the equipment and/or parts identified in this Agreement as expressly agreed to be provided by Seller to Purchaser. As used herein, the "Services", if any, are the services identified in this Agreement as expressly agreed to be provided by Seller to Purchaser. As used herein, the "Software", if any, is the software identified in this Agreement as expressly agreed to be licensed by Seller to Purchaser. These General Terms and Conditions of Sale (the "Terms"), Seller's quote, Purchaser's Purchase Order and Seller's Order Acknowledgement are collectively referred to in the Terms as the "Agreement". The Agreement sets forth the entire, exclusive and complete agreement of Seller and Purchaser with respect to the sale and purchase of the Equipment, the performance of the Services and the license of the Software and supersedes any prior or contemporaneous written or oral agreement, understanding and communications and any course of dealing, usage of trade or course of performance. This Agreement prevails over any of Purchaser's terms and conditions of purchase or purchase order, regardless of whether or when Purchaser submitted such terms and conditions or purchase order. Fulfillment of Purchaser's order does not constitute acceptance of any of Purchaser's terms and conditions and does not serve to modify or amend these terms and conditions. No waiver or modification of this Agreement shall be effective unless in writing and signed by both Seller and Purchaser. Quotes are subject to change without notice. Prices quoted shall be firm for orders scheduled by Seller to be delivered within sixty (60) days after the quotation date; otherwise, Seller reserves the right to apply prices in effect at the time of delivery.

2. PERFORMANCE CONDITIONS: The performance of the Equipment covered in this Agreement cannot be exactly predicted for every operating condition. In consequence, any predicted performance data submitted is intended to show probable operating results which may be closely approximated, but which cannot be guaranteed.

3. ENGINEERING: Seller and Purchaser acknowledge and contemplate that any engineering services for which Seller is responsible pursuant to this Agreement will be performed by engineers employed by Seller only to the extent allowed by applicable laws and regulations. Otherwise, such engineering services will be provided by qualified, licensed engineers selected and retained by Seller at Seller's expense. Except as otherwise provided herein, Seller and Purchaser acknowledge and contemplate that upon acceptance of this Agreement by Seller, Seller's engineering department or a qualified, licensed engineer selected and retained by Seller at Seller's expense will perform whatever engineering analysis and design is necessary to fulfill its obligations under this Agreement, and will prepare whatever plant layouts, drawings, and design specifications are necessary in Seller's discretion to facilitate the performance of the Equipment in accordance with this Agreement. Seller and Purchaser further acknowledge and contemplate that this engineering process may result in modifications or changes which may include, but are not limited to: modifications in conveyor lengths, sizes, speeds, angles, or positions; changes in motor sizes; changes in Equipment or plant configuration; and modifications or parts lists. No such modifications or changes shall constitute a breach of contract by Seller.

4. DRAWINGS: Seller will furnish Purchaser with necessary drawings and instruction for Purchaser's erection or installation of the Equipment. Seller will not be held responsible for design and/or installation of footings and/or other items necessary for installing the Equipment unless otherwise stated herein.

5. DIFFERING SITE CONDITIONS: If, in the performance of this Agreement, subsurface or latent conditions at the site are found to be materially different from those indicated by geotechnical reports provided by Purchaser, or unknown conditions of an unusual nature are disclosed differing materially from those ordinarily encountered by Seller, then such conditions may result in adjustments to the Price, anticipated dates for delivery/shipment, and other contractual obligations. No such adjustments shall constitute a breach of contract by Seller.

6. CONFIDENTIALITY: All non-public, confidential or proprietary information of Seller, including but not limited to specifications, samples, patterns, designs, plans, drawings, documents, data, business operations, purchaser lists, pricing, discounts or rebates, disclosed by Seller to Purchaser, whether disclosed orally or disclosed or accessed in written, electronic or other form or media, and whether or not marked, designated or otherwise identified as "confidential" in connection with this Agreement shall be treated by Purchaser as confidential and may not be disclosed to any third party or copied by Purchaser unless authorized in advance by Seller in writing. Upon Seller's request, Purchaser shall return all documents and other materials received from Seller. Seller shall be entitled to seek injunctive relief for any violation of this Paragraph 6. This Paragraph 6 does not apply to information that is: (a) in the public domain; (b) Purchaser can show was known to Purchaser at the time of disclosure; or (c) Purchaser can show was rightfully obtained by Purchaser on a non-confidential basis from a third party. Purchaser's confidentiality, non-disclosure and non-use obligations herein shall remain in force for the maximum term permitted by applicable law.

7. WARRANTY:

a. Seller warrants that upon shipment from Seller's site and continuing for a period of fifteen (15) months from shipment from Seller's site (the "Equipment Warranty Period"), so long as shipment occurs within sixty (60) days of Seller's Ready to Ship Notification to Purchaser, that the Seller manufactured Equipment will be free of defects in material and workmanship, provided any operation of the Equipment by Purchaser has been in accordance with generally approved practice as instructed by Seller service personnel or set forth in Seller service instructions, if any, and provided that Purchaser notifies Seller in writing as soon as such defect becomes apparent, but in all events during the Equipment Warranty Period. Notwithstanding the foregoing, the Equipment Warranty Period for burner blast tubes (Firing Heads), and mesh head elements is five (5) years from shipment from Seller's site; provided that the warranty on mesh head elements is prorated at 20% / year. Seller shall repair, or at its option replace EXW point of shipment, any defective Equipment or parts covered by the warranty. If the Purchaser is entitled to a claim under this warranty, Purchaser shall, as a condition precedent to securing warranty performance, return the Equipment to Seller's plant, 2001 South 21st Street, Parsons, Kansas, transportation prepaid. Notwithstanding the foregoing, where repair or replacement is deemed by Seller to be commercially impractical, Seller may choose to refund the Price upon return of the Equipment. The right to have defective Equipment repaired or replaced shall constitute the Purchaser's sole and exclusive remedy for breach of this limited Equipment warranty. Labor for defective Equipment repair will be paid by Purchaser under a formula determined by Seller. For helical coils found in Seller's HCS heaters, the Equipment Warranty Period for the helical coils is three (3) years. For helical coils found in Seller's HC heaters, the Equipment Warranty Period for the helical coils is five (5) years. Equipment which is repaired or replaced shall carry a warranty equal to the unexpired portion of the Equipment Warranty Period.

b. Seller makes no warranties or guarantees with respect to Equipment not manufactured by Seller, including but not limited to diesel engines, motors, motor starters, pumps, mixers, mills, scales, speed reducers, and other assemblies, valves, pressure regulators, solenoids, electronic drives, pressure differential switches, temperature sensing switches, flame scanners, gauge boards, modulating actuators, electronic displays, pressure transmitters, radar sensors, other electronic controls and instrumentation and other parts and accessories. Liners, castings, furnace refractories, and refractory materials are subject to wide variations of destructive service, are also not covered by the Equipment warranty and are a maintenance responsibility of Purchaser from the beginning of operation. Seller will pass through to Purchaser any warranties and limitations provided by the original manufacturer of parts used in the Equipment manufactured by Seller, but Seller does not provide any warranty as to such items.

c. Seller warrants that the Services performed hereunder shall be free from defects in workmanship for a period of ninety (90) days from the date of performance (the "Service Warranty Period"). Seller undertakes at its cost to reperform defective Services covered by the warranty, provided that Purchaser notifies Seller in writing as soon as such defect becomes apparent, but in all events during the Service Warranty Period. The right to have defective Services reperformed shall constitute the Purchaser's sole and exclusive remedy for breach of this limited Service warranty. Services which are reperformed shall carry a warranty equal to the unexpired portion of the Service Warranty Period.

d. No warranty shall apply to Equipment which has been repaired or altered by others so as, in Seller's judgment, to adversely affect the same or which shall have been subject to negligence, accident, abuse or improper care, installation, maintenance, clogged or storage or other than normal use or service, during or after shipment. No warranty shall apply to any used Equipment or for ordinary wear and tear, or ordinary corrosion or erosion, or clogged or damaged filters. No warranty shall apply to any Equipment adversely affected by being used with any machinery, part or accessory not manufactured or authorized by Seller. No warranty shall apply to consumables or parts having a life expectancy shorter than the Equipment Warranty Period.

e. Seller does not warrant or represent that any Equipment furnished by it meets any federal, state or local safety, environmental or electrical regulations. Seller is wholly discharged from all liability under this warranty in the event that Purchaser fails to pay for the Equipment or Services in accordance with the applicable purchase terms. This Equipment warranty extends only to the first end-user and is not transferable. This warranty may not be modified except pursuant to a written agreement signed by Seller.

f. THE EXPRESS WARRANTIES AND WARRANTY REMEDIES PROVIDED IN THIS PARAGRAPH 7 ARE THE SOLE AND EXCLUSIVE WARRANTIES AND WARRANTY REMEDIES PROVIDED BY SELLER TO PURCHASER AND ARE PROVIDED IN LIEU OF ALL OTHER WARRANTIES, WHETHER EXPRESS OR IMPLIED (EXCEPT WARRANTY OF TITLE), INCLUDING, BUT NOT LIMITED TO, ANY IMPLIED WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE AND ANY IMPLIED WARRANTY FROM COURSE OF DEALING OR USAGE OF TRADE, ALL OF WHICH ARE HEREBY EXPRESSLY WAIVED AND DISCLAIMED.

8. LIMITATION OF LIABILITY: NOTWITHSTANDING ANYTHING ELSE TO THE CONTRARY CONTAINED IN THIS AGREEMENT, THE PARTIES AGREE THAT IN NO EVENT OR CIRCUMSTANCE IS SELLER LIABLE TO PURCHASER FOR SPECIAL, INDIRECT, INCIDENTAL, PUNITIVE OR CONSEQUENTIAL DAMAGES, COSTS OR LOSSES OF ANY NATURE WHATSOEVER, INCLUDING BUT NOT LIMITED TO LOST PROFITS OR REVENUE, LOSS OF PRODUCTION, LOSS OF USE OR LOSS OF CONTRACTS, COSTS FOR RAW MATERIAL, ENERGY, UTILITY, LABOR OR CAPITAL OR FOR ANY OTHER INDIRECT LOSS; OR FOR CLAIMS RAISED BY PURCHASER'S CUSTOMERS; AND WHETHER BASED ON BREACH OF CONTRACT OR WARRANTY, TERMINATION, NEGLIGENCE, TORT, STRICT LIABLITY, INDEMNITY AT LAW OR IN EQUITY OR OTHERWISE. IN NO EVENT SHALL SELLER'S AGGREGATE LIABILITY ARISING OUT OF OR RELATED TO THIS AGREEMENT, WHETHER ARISING OUT OF OR RELATED TO BREACH OF CONTRACT, TORT (INCLUDING NEGLIGENCE) OR OTHERWISE, EXCEED THE TOTAL OF THE AMOUNTS PAID TO SELLER FOR THE EQUIPMENT SOLD HEREUNDER.

9. INSURANCE: From the date Seller notifies Purchaser that the Equipment is ready to ship, until the date the Equipment is paid for in full, Purchaser shall provide and maintain insurance in an amount no less than the total value of the Equipment delivered hereunder which insurance provides coverage against customary casualties and risks, including fire and explosion, and shall also provide coverage against liability for accidents or injuries to the public or to employees, in the names of Seller and Purchaser, as their interest may appear, and in amounts satisfactory to Seller. If Purchaser fails to provide such insurance, it then becomes Purchaser's responsibility to notify Seller so that Seller may provide the same, and the cost thereof shall be added to the Price. All loss resulting from failure to affect such insurance shall be assumed by Purchaser.

10. SECURITY INTEREST; COST OF RECORDING: Purchaser hereby conveys and grants to Seller a purchase money security interest in the Equipment to secure payment by Purchaser of all amounts due hereunder including the Price and such other debts, obligations and liabilities of Purchaser to Seller which may now exist or hereafter arise, whether absolute or contingent, or primary or secondary, together with all extensions or renewals for the foregoing and all expenses, legal or otherwise (including court costs and reasonable attorney's fees) incurred by Seller in collecting or endeavoring to collect any or all of the foregoing, in protecting any collateral and in enforcing the Agreement. The Equipment shall remain personal property in all respects notwithstanding the manner of annexation of any of the Equipment to realty. Purchaser agrees to execute any instrument or document considered necessary by Seller to perfect its security interest in the Equipment, including, but not limited to, financing statements, chattel mortgages, deeds of trust, deeds to secure debt, mortgages or other security instruments. Until default hereunder, Purchaser may have possession of the Equipment and use the same in any lawful manner not inconsistent with this Proposal or with any policy of insurance thereon. Purchaser will pay the costs and taxes due for recording and filing any Financing, Continuation or Termination Statements with respect to Seller's security interest in the Equipment or in connection with any of the other security documents referred to above.

11. EQUIPMENT NOT TO BE REMOVED: As long as the security interest in the Equipment is retained by Seller, the Equipment shall not be removed from the erection site and Purchaser shall not permit, voluntarily or involuntarily, the Equipment or any part of it to be sold, transferred, encumbered, attached, seized or removed in any manner whatsoever.

12. DEFAULT: Upon default by Purchaser in the payment of the Price or any portion thereof when due or in the payment of all or any portion of any other indebtedness secured under this Agreement when due or in the performance of any other term or provision hereof, all unpaid amounts due Seller shall thereupon be immediately due and payable and Seller shall have the rights and remedies contained herein and the rights and remedies of a secured party under the Uniform Commercial Code of the State of Tennessee or under the laws of any other jurisdiction as a court of competent jurisdiction shall determine to be applicable. In the event of Purchaser's default, the following provisions shall apply: (a) Purchaser shall, upon request of Seller, disassemble the Equipment and make it available to Seller at a place designated by Seller; (b) Seller may enter Purchaser's premises where any part of the Equipment is located, and take possession of and remove all or any portion of the Equipment for purposes of disposition pursuant hereto; (c) Purchaser agrees that sales for cash or on credit to a wholesaler, retailer, or user or property of the type subject to this Agreement or at public auction or private sale are all commercially reasonable; (d) Seller shall give Purchaser notice of the time and place of any sale of any of the Equipment or of the time after which any private sale or any other intended disposition thereof is to be made by notice, postage prepaid and addressed to Purchaser at the latest address of Purchaser appearing on the records of Seller at least seven (7) days before the time of the sale or other disposition, which provisions for notice Purchaser and Seller agree are reasonable; (e) any proceeds of any disposition of any of the Equipment may be first applied by Seller to the payment of expenses in connection with exercising its rights and remedies hereunder, including reasonable attorney's fees and legal expenses, and any balance of such proceeds may be applied as Seller may elect in its sole discretion; (f) if the sale or other disposition of the Equipment fails to satisfy in full obligations of Purchaser secured by this Agreement, and the reasonable expenses of retaking, holding, preparing for sale, selling and the like, including reasonable attorney's fees and legal expenses incurred by Seller in connection with this Agreement or the obligation it secures, Purchaser shall be liable for any deficiency.

13. PERMITS AND APPROVAL OF PLANS: Purchaser assumes all responsibility for securing any necessary governmental approvals of the plans and specifications and any permits required for the installation and operation of the Equipment, all at Purchaser's expense.

14. PERMIT CONTINGENCY: If the purchase of Equipment under this Agreement is contingent on Purchaser's receipt of one or more permits or other governmental approvals, then the Price set forth in this Agreement will not be binding on Seller. Once all contingencies have been fulfilled or are waived, the Price will be determined by Seller taking into account any increase in Seller's cost of purchased components and/or raw materials, among other factors.

15. COMPLIANCE WITH APPLICABLE LAWS: Purchaser assumes all responsibility for complying with all federal, state and local statutes, laws, codes, regulations and ordinances in connection with the installation and operation of the Equipment and any other activity related thereto, including, without limitation, all federal, state and local environmental laws and regulations relating to pollution and protection of the environment and the Occupational Safety and Health Act and all rules and regulations promulgated thereunder.

16. PATENTS: In the event that any of the Equipment specified in this Agreement is based upon designs of or furnished by Purchaser, Purchaser shall indemnify Seller for any loss or expense incurred by it by reason of any claim for infringement of patents.

17. SHIPMENT:

a. If Purchaser is in default of any of its obligations under this Agreement, Seller may, at its election, withhold any further performance of its obligations and duties under this Agreement until such time as such default has been cured by Purchaser, in which event the anticipated date of shipment as set forth herein shall be adjusted accordingly. Seller shall not be liable or responsible for, nor shall the Price be reduced by any amount because of any matters beyond the control of Seller which delay or postpone the anticipated date set forth above for the shipment of the Equipment, such matters including, but not limited to, warlike acts, civil disorder, governmental restriction, acts of God, prior sale, acceptance of United States governmental contracts, strike, lockout, accidents, freight embargo, fire, flood, inability of Seller to obtain necessary materials, supplies, labor or transportation, pandemic, or any unforeseen water, soil or rock conditions.

b. A detailed shipping list will accompany the bill of lading and Purchaser agrees to check the Equipment as it is unloaded and any claim for shortage against Seller will be made in writing within twenty-four (24) hours of time of unloading, to be followed by an affidavit (if required) from the person in charge of the unloading. Claims for loss or damage in transit will be made on the carrier by Purchaser.

c. Except to the extent otherwise provided herein, Purchaser has full responsibility for erection and/or installation of the Equipment.

18. LATE CHARGES AND ATTORNEY'S FEES: Purchaser agrees that in the event any amount payable by Purchaser to Seller remains unpaid for more than 30 days, a service charge of 1.5% per month (18% per annum) or any portion thereof (or the highest rate of interest allowed by law, whichever is less) shall accrue on such unpaid amount beginning on the thirty-first (31st) day after such date payment is due. If the indebtedness, including late charges, arising out of this or any other transaction between Seller and Purchaser is placed in the hands of an attorney for collection, or is collected by and through an attorney, Purchaser will pay all costs of collection, including without limitation, court costs and reasonable attorney's fees.

19. POSTPONED DELIVERY (INCLUDING SHIPPING DELAY): If, through no fault of Seller, delivery or shipment is delayed or postponed (including deferral of shipment requested by Purchaser), Purchaser shall pay to Seller any additional costs, including plant Equipment storage, handling, and insurance, incurred by Seller arising from such delay, deferral, or postponement. Such a delay, postponement or deferral is considered "offer to ship" or "shipment" for all purposes, including invoicing, payment and transfer of title. Therefore, the balance remaining unpaid on the Price shall become due and payable immediately. Purchaser shall bear the risk of loss of or damage to the Equipment during storage and thereafter. If, as a result of the delay, postponement or deferral, the Equipment requires repainting, all costs associated with repainting shall be paid by the Purchaser. Should Purchaser delay/postpone/defer shipment, Purchaser and Seller will complete the attached "Postponed Delivery/Shipping Delay/Deferral Notice".

20. EQUIPMENT CERTIFICATION: Once certification and fabrication has been completed on control houses and power houses, if state certification specifications change or unit(s) are to be shipped to a location other than that for which the certification was acquired, the cost of any recertification and/or modifications required to be done on the Equipment shall be paid by Purchaser.

21. LIMITATION OF PROPOSAL: The Price and terms quoted in this Sales Proposal are subject to formal acceptance (i.e. signature on this Sales

Proposal) without change by Purchaser within a period 30 days from the date hereof, except that Seller shall have the right to withdraw its Sales Proposal at any time before formal acceptance by Purchaser.

22. EXECUTION OF CONTRACT: This Sales Proposal is merely the solicitation of an order and is not an offer from Seller to Purchaser (even though executed on behalf of Seller under "RESPECTFULLY SUBMITTED,") and does not obligate Seller in any manner whatsoever until this Agreement is both executed below on behalf of Purchaser as an order made to Seller as well as executed below on behalf of Seller as an acceptance of such order from Purchaser, at which time this Agreement shall become a binding contract between Seller and Purchaser. Once this Agreement has become a binding contract, it cannot be suspended or cancelled without the prior written consent of Seller, which may be withheld in the sole discretion of Seller. In no event will consent to suspension or cancellation be given without full reimbursement by Purchaser of all Seller's expenses, damages and losses arising from such cancellation or suspension and incurred through the date of cancellation or suspension, plus reasonable overhead and profit allocation on such amounts.

23. SEVERABILITY: If any provision of this Agreement is found to be legally invalid or unenforceable: (i) the validity and enforceability of the remainder of this Agreement shall not be affected, (ii) such provision shall be deemed modified to the minimum extent necessary to make such provision consistent with applicable law, and (iii) such provision shall be valid, enforceable and enforced in its modified form.

24. ASSIGNMENT: Purchaser shall not assign any of its rights or delegate any of its obligations under this Agreement without the prior written consent of Seller. Any purported assignment or delegation in violation of this Paragraph 24 is null and void. No assignment or delegation relieves Purchaser of any of its obligations under this Agreement.

25. LAW CONTROLLING: This Agreement and all questions regarding the performance of the parties hereunder shall be controlled by the laws of the State of Tennessee (without regard to conflicts of law). The parties agree that the United Nations Convention on Contracts for the International Sale of Goods does not apply to this Agreement, or the transactions contemplated thereby.

26. DISPUTE RESOLUTION: Any dispute or claim arising out of or relating to this Agreement, or the breach, termination or invalidity thereof, and any related tort, statutory and equitable claims (each a "Dispute"), which the parties are not able to settle amicably within 3 months from the first written request for such settlement, shall be brought exclusively in a state or federal court in the State of Tennessee, County of Hamilton. The parties hereby waive any right to challenge such choice of jurisdiction or venue or to seek transfer to another jurisdiction. THE PARTIES FURTHER KNOWINGLY AND VOLUNTARILY WAIVE ANY RIGHT TO A JURY TRIAL OF THE DISPUTE.

27. TAXES: Prices quoted herein do not include any Federal, State or Municipal Taxes. If under existing or future law passed by the United States, any state or any municipality, Seller, in its opinion, is required to pay or collect a tax, impost or charge upon the manufacture, sale, use or assembly of the material described herein, the Price shall be increased by the amount of such tax, impost or charge. The amount of such increase is to be paid to Seller upon demand. If Purchaser holds resale tax permits and the material described herein is for resale, such information shall be shown by Purchaser.

28. BACK-CHARGES AND ALLOWANCES: Seller shall not be called upon to make any allowance for material, labor, repairs or alterations made for its account unless authorized by Seller in writing.

29. INSPECTION AND ACCEPTANCE PERIOD: Purchaser agrees to inspect the Equipment immediately after delivery to the site, but in no event later than five (5) calendar days after such delivery (the "Acceptance Period"). Any defect discovered during the Acceptance period is subject to the procedures and remedies set forth in Paragraph 7 (Warranty).

30. RESPONSIBILITY OF PURCHASER FOR OPERATION OF EQUIPMENT: The operation of the Equipment at all times shall be the sole and exclusive responsibility of Purchaser or any end user. Any Services by Seller's representatives shall be given solely in a consulting or advisory capacity and shall not release Purchaser or any end user in any manner whatsoever from its responsibility for operating the Equipment.

31. INDEMNIFICATION: Purchaser agrees to indemnify and hold harmless Seller, its affiliates and their respective employees from and against any and all liabilities, damages, obligations and claims (including, without limitation, court costs and reasonable attorney's fees) arising from or with respect to the operation of the Equipment. Without limiting the generality of the preceding sentence, the parties acknowledge and agree that if a claim initially was brought against Seller for defective manufacture, design or the like and was finally determined by a court of competent jurisdiction or otherwise settled (such settlement being with Purchaser's consent) on a basis relating to the negligent operation or use of the Equipment, Seller will be entitled to indemnification pursuant to the provisions of the preceding sentence.

32. TITLE AND RISK OF LOSS: Title to the Equipment shall pass to Purchaser upon shipment or offer to ship should Purchaser delay shipment. The risk of loss or damage to the Equipment shall pass to Byer upon delivery of the Equipment (EXW point of shipment Seller site, Incoterms 2020), unless transferred earlier in accordance with Paragraph 19 (Postponed Delivery (Including Shipping Delay)).

33. NOTICES: Each party shall deliver all notices and other communications under this Agreement (each, a "Notice") in writing and addressed to the other party at the addresses set forth on the first page of this Sales Proposal. Each party shall deliver all Notices by personal delivery or through deposit in the mail, certified or registered (in each case, return receipt requested, postage prepaid) or through a nationally recognized overnight courier (with all fees prepaid). If Notice should be given immediately or promptly, then in addition to furnishing a copy of the Notice in the manner aforesaid, a copy shall be sent via e-mail (with confirmation of transmission). A Notice is effective only (a) upon receipt by the receiving party and (b) if the party giving the Notice has complied with the requirements of this Section 33, unless the receiving party has waived its requirements in writing. A copy of all notices to Seller shall be sent to: Power Flame, 1725 Shepherd Road, Chattanooga, TN 37421, Attn: Legal Counsel.

34. WEIGHTS: Shipping weights or dimensions wherever shown in price lists, catalogs and as show in proposals or quotations, are approximate and are not guaranteed.

35. DESIGN CHANGES: Seller reserves the right to make changes in design from time to time as are deemed desirable without incurring the obligation to furnish them for Equipment previously sold or shipped.

36. PAINTING: Before shipment, Seller will apply one coat of standard paint to all structural and plate work, and two coats to paving machines.

37. SAFETY DEVICES: The Equipment is provided with only those safety devices identified herein. It is the responsibility of Buyer to furnish other appropriate safety devices which are desired by Buyer and/or required by OSHA or other laws and regulations.

38. ELECTRICAL EQUIPMENT AND WIRING: Seller cannot assume responsibility that any weather-resistant cords, plugs or receptacles included with its power and/or control panels will be acceptable under the applicable electrical code. Buyer is responsible for any disconnect switches or other devices required in addition to the main disconnect switch in the power panel. Scale, probe or moisture meter cables or wires are not to be installed underground, and each is to be kept isolated from all other power and/or signal wires.

39. DISCONTINUANCE, IMPROVEMENT AND DESIGN CHANGES. Seller may discontinue the manufacture of any Equipment or make changes or improvements at any time in the specifications, construction or design of any Equipment without incurring any obligation to Buyer. Equipment so changed or improved will be accepted by Buyer in fulfillment of existing orders.

Appendix C

RACT Analysis – Emergency Generators

Emission Units HA13, HA14, HA18, FL09, FL10, BA04, BA05, BA11, BA12, CR07, CP13, CP14, CP15, CP16, CP17, CP28, CP29, PA17, PA18, IP08, IP09, PH10, PH11, PH12, PH13, LI06 and LI07

APPENDIX C

RACT Analysis

Emergency Generators, Emission Units HA13, HA14, HA18, FL09, FL10, BA04, BA05, BA11, BA12, CR07, CP13, CP14, CP15, CP16, CP17, CP28, CP29, PA17, PA18, IP08, IP09, PH10, PH11, PH12, PH13, LI06 and LI07

Appendix C
Table of Contents

1.0 General

This appendix summarizes the Reasonably Available Control Technology (RACT) Analysis performed for the emergency generators, Emission Units (EU) HA13, HA14, HA18, FL09, FL10, BA04, BA05, BA11, BA12, CR07, CP13, CP14, CP15, CP16, CP17, CP28, CP29, PA17, PA18, IP08, IP09, PH10, PH11, PH12, PH13, LI06 and LI07 located at various properties associated with various Caesars Entertainment, Inc. properties. The basic steps for this analysis are as follows:

- Identification of existing equipment and baseline emissions
- Identification of available control options
- Elimination of technically infeasible control options
- Determination of the cost effectiveness of control options
- Evaluation of the benefits and disadvantages (environmental, energy and economic) associated with the technically feasible control options
- Identification of RACT control technology including emission limitations, monitoring, testing, recordkeeping and reporting requirements

Controls for oxides of nitrogen (NO_X) are evaluated in this appendix.

2.0 NO_X RACT Assessment

2.1 Equipment Description and Limitations

EUs HA13, HA14, HA18, FL09, FL10, BA04, BA05, BA11, BA12, CR07, CP13, CP14, CP15, CP16, CP17, CP28, CP29, PA17, PA18, IP08, IP09, PH10, PH11, PH12, PH13, LI06 and LI07 have ratings varying from 600 kW to 2,100 kW and are all powered by compression ignition engines utilizing diesel as the fuel supply. They are all limited to 100 hours of operation per year for testing and maintenance purposes and up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. All of the engines are turbo-charged and aftercooled.

Due to the large number of generators requiring a RACT analysis for this source, individual emission units were grouped according to the power rating of the engine (hp). This is a reasonable approach since the engine horsepower ratings for each engine will largely determine the type and size of control device possible.

2.2 Baseline Emissions

As noted in Section 3 of the report, baseline emissions can be set equivalent to actual emissions if actual emissions for the three previous consecutive years are 70% or less of the source's or individual emission unit's potential emissions. Caesars meets this criterion on both a facility-wide basis and individual emissions unit basis.

Table 1 summarizes the baseline NO_X emissions for each emission unit.

Table 1 – Baseline Emissions for the Emergency Generators

Emission Unit	Engine Rating (hp)	Generator Rating (kW)	NO_X Emissions[1] (tons/year)
HA14, IP08, IP09	890	600	0.25
FL09, FL10	1109	750	0.28
HA18	1180	800	0.34
HA13	1232	800	0.21
CP16	1818	1250	0.67
BA04, BA05, BA11, BA12	1340	1000	0.26
CP15	2520	1750	0.78
PH10, PH11, PH12	2550	1750	0.30
PH13	2561	1750	0.13
PA17, PA18	2816	2000	0.45
CP13, CP14, CP17	2876	2000	1.04
CR07, CP28, CP29, LI06, LI07	3634	2000	0.56

Notes: [1] Maximum annual emissions for 2019 - 2021 for each group.

2.3 Identification and Technical Feasibility of NO_X Control Options

2.3.1. Identification of Available Controls

A review of the most recent (5 years) determinations contained in the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC) was conducted to identify any recent RACT determinations for generators of the same or comparable size. The database did not contain any RACT determinations for this time period. In addition, various U.S. EPA control technology reports were reviewed and the current contractor responsible for servicing the Caesars' emergency generators was consulted to identify potential controls. Based on the information obtained, the proposed NO_X control technology for the emergency generators is summarized in Table 2. It should be noted that all Caesars generators are equipped with turbochargers and aftercoolers which are considered the baseline control technology options for these emission units.

Table 2 – Available NO_X Control Technology Methods for the Emergency Generators

Control Equipment	NO_X Reduction Potential (%)	Range of Application	Commercial Availability/ R&D Status
Selective Catalytic Reduction (SCR)	90	Limited range of application	Commercially available

The technical feasibility of this control option will next be evaluated.

2.3.2. Selective Catalytic Reduction (SCR)

SCR involves the injection of ammonia in the boiler exhaust gases in the presence of a catalyst. The catalyst allows the ammonia to reduce NO_X levels at lower exhaust temperatures than selective non-catalytic reduction (SNCR). Unlike SNCR, where the exhaust gases must be approximately 1400-1600°F, SCR can be utilized where exhaust gases are between 500° F and 1200° F, depending on the catalyst used. SCR can result in NO_X reductions up to 90%. SCR systems are technically feasible for retrofit on existing generators.

2.3.3. Technological Feasibility Summary

Table 3 summarizes the technological feasibility evaluations of the identified control option.

Table 3 – NO_X Control Technology Methods for the Emergency Generators

Control Equipment	Technically Feasible?	Uncontrolled NO_X Emissions (tons/year)	NO_X Controlled Emission Rate (tons/year)	NO_X removed (tons/year)
SCR	Yes	0.25 - 1.04	0.01 - 0.10	0.12 - 0.94

Based on the information presented in Table 3, Caesars will evaluate the cost of installing SCR systems with a control efficiency of 90%.

2.4 Cost of NO_X Control Options

For the technically feasible method of control alternative, a total annualized equipment cost and an annual operating cost has been calculated. The calculation of the capital cost recovery factor used to estimate the annualized equipment cost assumes an interest rate of 6% and equipment life of 10 years. The individual cost calculations for each group of emissions units based on the size of the SRC system required are included in Attachment B-2. The capital cost for each generator is based on the actual quote from an equipment vendor. A copy of the quote obtained is included with Attachment B-2. The calculated costs are summarized in Table 4.

Table 4 – Cost of NO_X Control Options for the Emergency Generators

EU	Method of Control	Annualized Cost ($/year)	Estimated NO_X Removal (tons/year)	Cost Effectiveness ($/ton removed)
HA14, IP08, IP09	SCR	$25,938	0.23	$115,282
HA13, HA18, FL09, FL10, BA04, BA05, BA11, BA12	SCR	$27,385	0.31	$89,494
CP15, CP16	SCR	$27,862	0.70	$39,690
PH13	SCR	$27,627	0.12	$236,127
CR07, PH10, PH11, PH12	SCR	$29,668	0.27	$109,880
CP13, CP14, CP17,CP28, CP29, PA17, PA18, LI06, LI07	SCR	$32,224	0.94	$34,427

2.5 Environmental, Energy & Economic Considerations

2.5.1. Environmental Impacts

As shown in Table 4, there is only a minimal potential reduction in NO_X emissions associated with the installation of an SCR system.

2.5.2. Energy Impacts

It is anticipated that only minimal adverse energy impacts would be associated with an SCR system.

2.5.3. Economic Impacts

The economic impacts analysis is based on the cost effectiveness of each technology in terms of the cost per ton of removed pollutant as evaluated in Section 2.4. A maximum cost effectiveness threshold for NO_X RACT has not been established by DAQ. In 1994, the U.S. EPA recommended a maximum of $1,300 per ton to represent RACT at that time. Based on the increase in the Chemical Engineering Plant Cost Index (CEPCI) between then and now, this equates to approximately $3,000 per ton for the present. The U.S. EPA, in its approval of certain State Implementation Plan revisions for Pennsylvania (85 FR 65706) noted that Pennsylvania's proposed maximum of $2,800 per ton was low compared to other states but approved it. Maximum thresholds for other jurisdictions were presented in the notice as follows:

- Wisconsin, $2,500 per ton NO_X
- Illinois, $2,500—$3,000 per ton NO_X
- Maryland, $3,500—$5,000 per ton NO_X
- Ohio, $5,000 per ton NO_X
- New York, $5,000—$5,500 per ton NO_X

For the purpose of this analysis, even if the maximum value of $5,500 from above is deemed appropriate in Clark County, the cost of control for each individual boiler significantly exceeds this value. Table 4 presents the cost effectiveness of the viable control option upgrades. The costs exceed the most stringent RACT thresholds several times over.

3.0 NO_X RACT Determination

After eliminating the technically feasible control option and evaluating this control technology for environmental, energy, and economic impacts, it is evident that emission units HA13, HA14, HA18, FL09, FL10, BA04, BA05, BA11, BA12, CR07, CP13, CP14, CP15, CP16, CP17, CP28, CP29, PA17, PA18, IP08, IP09, PH10, PH11, PH12, PH13, LI06 and LI07 can be considered to comply with RACT with existing emission limitations (turbochargers and aftercoolers), monitoring, testing and recordkeeping. Caesars shall operate and maintain all diesel generators in accordance with the manufacturer's O&M manual for emission-related components.

ATTACHMENT C-1

Attachment C-1
Cost Effectiveness Calculation
SRC6X4-16

Emission Unit/Control Technology

Emission Unit	HA14, IP08, IP09
Emission Unit Description	Emergency Generator
Control Technology	SCR
Baseline Emission Rate[1] (tons/year)	0.25
Emission Reduction[2] (%)	90%
Controlled Emissions (tons/year)	0.03

Annualized Capital Costs

Initial Capital Investment[3]	$119,571
Direct & Indirect Costs[4]	$15,340
Total Capital Investment	$134,910
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$18,330

Annual Operating Costs

Urea	$595
Catalyst[5]	$1,013
Maintenance[6]	$6,000
Total Annualized Cost	$25,938

Cost Effectiveness

Emissions Reduction (tons/year)	0.23
Cost Effectiveness of NO_X Reduction ($/ton)	$115,282

Notes:

[1] Maximum actual emissions for 2019 - 2021 for group.

[2] Vendor specification.

[3] Cost based on vendor estimate.

[4] Installation, startup and performance testing.

[5] One replacement averaged over 10 years.

[6] Estimate.

Attachment C-1
Cost Effectiveness Calculation
SRC6X6-18

Emission Unit/Control Technology

Emission Unit	HA13, HA18, FL09, FL10, BA04, BA05, BA11, BA12
Emission Unit Description	Emergency Generator
Control Technology	SCR
Baseline Emission Rate[1] (tons/year)	0.34
Emission Reduction[2] (%)	90%
Controlled Emissions (tons/year)	0.03

Annualized Capital Costs

Initial Capital Investment[3]	$125,615
Direct & Indirect Costs[4]	$15,340
Total Capital Investment	$140,955
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$19,151

Annual Operating Costs

Urea	$714
Catalyst[5]	$1,520
Maintenance[6]	$6,000

Total Annualized Cost	$27,385

Cost Effectiveness

Emissions Reduction (tons/year)	0.31
Cost Effectiveness of NO_X Reduction ($/ton)	$89,494

Notes:

[1] Maximum actual emissions for 2019 - 2021 for group.

[2] Vendor specification.

[3] Cost based on vendor estimate.

[4] Installation, startup and performance testing.

[5] One replacement averaged over 10 years.

[6] Estimate.

Attachment C-1

Cost Effectiveness Calculation

SRC6X6-20

Emission Unit/Control Technology

Emission Unit	CP15, CP16
Emission Unit Description	Emergency Generator
Control Technology	SCR
Baseline Emission Rate[1] (tons/year)	0.78
Emission Reduction[2] (%)	90%
Controlled Emissions (tons/year)	0.08

Annualized Capital Costs

Initial Capital Investment[3]	$126,500
Direct & Indirect Costs[4]	$15,340
Total Capital Investment	$141,840
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$19,271

Annual Operating Costs

Urea	$1,071
Catalyst[5]	$1,520
Maintenance[6]	$6,000
Total Annualized Cost	$27,862

Cost Effectiveness

Emissions Reduction (tons/year)	0.70
Cost Effectiveness of NO_X Reduction ($/ton)	$39,690

Notes:

[1] Maximum actual emissions for 2019 - 2021 for group.

[2] Vendor specification.

[3] Cost based on vendor estimate.

[4] Installation, startup and performance testing.

[5] One replacement averaged over 10 years.

[6] Estimate.

Cost Effectiveness Calculation

SRC6X6-22

Emission Unit/Control Technology

Emission Unit	PH13
Emission Unit Description	Emergency Generator
Control Technology	SCR
Baseline Emission Rate[1] (tons/year)	0.13
Emission Reduction[2] (%)	90%
Controlled Emissions (tons/year)	0.01

Annualized Capital Costs

Initial Capital Investment[3]	$128,269
Direct & Indirect Costs[4]	$15,340
Total Capital Investment	$143,609
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$19,512

Annual Operating Costs

Urea	$595
Catalyst[5]	$1,520
Maintenance[6]	$6,000

Total Annualized Cost	$27,627

Cost Effectiveness

Emissions Reduction (tons/year)	0.12
Cost Effectiveness of NO_X Reduction ($/ton)	$236,127

Notes:

[1] Maximum actual emissions for 2019 - 2021 for group.

[2] Vendor specification.

[3] Cost based on vendor estimate.

[4] Installation, startup and performance testing.

[5] One replacement averaged over 10 years.

[6] Estimate.

Attachment C-1
Cost Effectiveness Calculation
SRC8X6-22

Emission Unit/Control Technology	
Emission Unit	CR07, PH10, PH11, PH12
Emission Unit Description	Emergency Generator
Control Technology	SCR
Baseline Emission Rate[1] (tons/year)	0.30
Emission Reduction[2] (%)	90%
Controlled Emissions (tons/year)	0.03
Annualized Capital Costs	
Initial Capital Investment[3]	$133,429
Direct & Indirect Costs[4]	$15,340
Total Capital Investment	$148,769
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$20,213
Annual Operating Costs	
Urea	$1,428
Catalyst[5]	$2,027
Maintenance[6]	$6,000
Total Annualized Cost	$29,668
Cost Effectiveness	
Emissions Reduction (tons/year)	0.27
Cost Effectiveness of NO_X Reduction ($/ton)	$109,880

Notes:

[1] Maximum actual emissions for 2019 - 2021 for group.
[2] Vendor specification.
[3] Cost based on vendor estimate.
[4] Installation, startup and performance testing.
[5] One replacement averaged over 10 years.
[6] Estimate.

Cost Effectiveness Calculation

SRC8X8-24

Emission Unit/Control Technology

Emission Unit	CP13, CP14, CP17,CP28, CP29, PA17, PA18, LI06, LI07
Emission Unit Description	Emergency Generator
Control Technology	SCR
Baseline Emission Rate[1] (tons/year)	1.04
Emission Reduction[2] (%)	90%
Controlled Emissions (tons/year)	0.10

Annualized Capital Costs

Initial Capital Investment[3]	$145,519
Direct & Indirect Costs[4]	$15,340
Total Capital Investment	$160,859
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$21,856

Annual Operating Costs

Urea	$1,666
Catalyst[5]	$2,702
Maintenance[6]	$6,000
Total Annualized Cost	$32,224

Cost Effectiveness

Emissions Reduction (tons/year)	0.94
Cost Effectiveness of NO_X Reduction ($/ton)	$34,427

Notes:

[1] Maximum actual emissions for 2019 - 2021 for group.

[2] Vendor specification.

[3] Cost based on vendor estimate.

[4] Installation, startup and performance testing.

[5] One replacement averaged over 10 years.

[6] Estimate.

Design Parameters

The following conditions were used to design the emergency standby SCR systems.

Table 1. Full Load Design Parameters per SCR

Tag No.	Engine	Engine HP	Gas Rate (Lb/hr)	Gas Temp (ºF)	Fuel	SCR Model	32.5% Urea
HA13	Detroit Diesel	1,232	13,500	920	ULSD	SCR6x6-18	<6 GPH
HA14, IP08, IP09	Caterpillar	890	9,500	920	ULSD	SCR6x4-16	<5 GPH
HA18	Caterpillar	1,180	13,500	920	ULSD	SCR6x6-18	<6 GPH
FL09, FL10	Caterpillar	1,109	13,500	920	ULSD	SCR6x6-18	<6 GPH
BA05, BA05, BA11, BA12	Detroit Diesel	1,340	13,500	920	ULSD	SCR6x6-18	<6 GPH
CR07	Caterpillar	2,206	16,800	930	ULSD	SCR8x6-22	<12 GPH
CP28, CP29, LI06, LI07	Caterpillar	2,937	22,400	930	ULSD	SCR8x8-24	<14 GPH
CP13, CP14, CP17	Caterpillar	2,876	22,000	930	ULSD	SCR8x8-24	<14 GPH
CP15	Caterpillar	2,520	17,400	930	ULSD	SCR8x6-22	<12 GPH
CP16	Caterpillar	1,818	15,300	920	ULSD	SCR6x6-20	<9 GPH
PA17, PA18	Cummins	2,816	22,000	930	ULSD	SCR8x8-24	<14 GPH
PH10, PH11, PH12	Detroit Diesel	2,550	17,400	930	ULSD	SCR8x6-22	<12 GPH
PH13	Detroit Diesel	2,560	17,400	930	ULSD	SCR6x6-22	<5 GPH

Table 2. Full Load Emissions Data per SCR

Exhaust Component	Catalyst Inlet	Catalyst Outlet	Required Reduction
NOx	10.89 g/hp-hr	1.08 g/hp-hr	90% minimum
NOx	5.08 g/hp-hr	0.50 g/hp-hr	90% minimum
NOx	5.23 g/hp-hr	0.52 g/hp-hr	90% minimum
NOx	4.53 g/hp-hr	0.45 g/hp-hr	90% minimum
NOx	5.39 g/hp-hr	0.53 g/hp-hr	90% minimum

Table 3. Full Load SCR System Data per SCR

Maximum Ammonia Slip	10 ppmvd @ 15% O2
Estimated 32.5% Urea Usage	Varies with engine NOx emissions – see above
Estimated System Pressure Loss (catalyst in new condition)	≤7.5″w.c.

NOTES:

Johnson Matthey has calculated the appropriate catalyst volume and necessary equipment to achieve the stated emission reductions based on the above Design Parameters. If the actual operating conditions are different from above conditions more catalyst and/or different equipment may be required for the system to achieve the required emission reductions. For this reason, all operating conditions must be closely reviewed and confirmed because different Parameters will void the warranty.

Emission reduction across catalyst is at steady state conditions, and with a maximum tolerance of + 3% deviation from the stated catalyst inlet emission value(s).

Equipment Description Per SCR System Per Engine

General Arrangement:

The proposed design is a horizontal configuration as shown on the referenced preliminary general arrangement drawings. Modifying the design to accommodate different specifications, configurations, etc. other than what is proposed will require a change to the price and/or shipment schedule.

Horizontal SCR Housing:

The SCR catalyst housing and catalyst tracks are fabricated from 400 series stainless steel. The housing is complete with a hinged catalyst access door, lifting lugs and misc. instrument connections. The floating catalyst tracks provide a labyrinth seal to prevent gas from by-passing the catalyst while minimizing the use for gaskets. Such gaskets tend to crack after thermal expansion and contraction cycles, and these cracks enable gas to by-pass the catalyst, which reduces the overall system performance.

Please refer to the following preliminary arrangement drawings for overall system dimensions SCR6x4

drawing number 202-C0031739 SCR6x6 drawing number 202-C0028769

SCR8x6 drawing number 202-CC0031740 SCR8x8 drawing number 202-C0028770

SCR10x8 drawing number 202-C0028771

Lot SCR Catalyst:

The SCR system will be provided with the catalyst type and volume that is needed to achieve the emission reductions which are listed above. Johnson Matthey designs and manufactures our own catalyst and has been doing so for decades. We integrate the proven performance of our catalyst into every SCR system that we provide. The catalyst is supplied in modules or blocks of sufficient size and weight to facilitate handling for loading the catalyst into the catalyst housing.

Horizontal Mixing Pipe:

The mixing pipe is optimized for the injection, atomization and mixing of the reductant into the engine exhaust gas. The pipe itself is fabricated from 300 series stainless steel and mixing duct internals are also fabricated from 300 series stainless steel. The pipe is supplied with internal mixers and all necessary fittings for the installation of the urea injection lance.

The dimensions of the mixing pipe vary with the SCR system size as indicated below.

SCR6x4-16 = 16″ diameter x 8′ long SCR6x6-18 = 18″ diameter x 8′ long

SCR6x6-20 = 20″ diameter x 8′ long SCR6x6-22 = 22″ diameter x 8′ long

SCR8x6-22 = 22″ diameter x 8′ long SCR8x8-24 = 24″ diameter x 8′ long

Urea Injection Control System:

This system will utilize an automatic urea injection system based on measurements from NOx sensors which are included with the SCR system. Requires Purchaser provided 4-20mA engine load signal and engine run signal.

The primary components of the urea injection control system are:

Control Panel – Painted carbon steel enclosure containing a touch screen Allen Bradley PLC with HMI and Modbus IP communication, on-off switch, on-off status indicator lights. Touch screen can be used for system commissioning and setup. System includes remote access capability for off-site monitoring. The control panel is mounted to the dosing panel that is described below. Both panels are designed for indoor installations. Please refer to the attached drawing for approximate overall dimensions of the panel**.**

Urea Dosing Panel – Attached to the control panel that is described above and contains the positive displacement urea metering pump (requires flooded suction), system purge valve, air regulator, air pressure switch, check valves, overpressure regulator, 3-way injection valve and leak detector.

Urea Injection Lance - Specially designed 2-phase 300 series stainless steel lance/nozzle assembly with high temperature protection.

Exhaust Gas Temperature Transmitter - To allow urea system to start injecting at temperatures greater than 575°F.

Available panel options include a stainless steel panel in lieu of painted carbon steel, a data logger, a modem for remote screen viewing, a heater and an air conditioner.

Instruction Manuals:

- Included are an electronic General Arrangement Approval Drawing, plus P&ID and the control/dosing panel general arrangement drawings and wiring schematic. Also included is an electronic Operation and Maintenance Manual for the SCR system.

Onsite Services:

Two (2) Technicians to install and test SCR over the course of Three (3) Days per Unit. Commissioning and Operation Inspection to include One (1) Four (4) hour load bank test using portable resistive load bank, to be completed during normal business hours, Monday thru Friday (excluding holidays). Additional trips or hours onsite, due to construction or other delays beyond our control, will be billed at extra cost at prevailing rate.

BASE PRICING:

SCR 8X8 - 24	Qty. 9	$1,309,673.00
SCR 8X6 - 22	Qty. 5	$667,147.00
SCR 6X6 - 22	Qty. 1	$128,269.00
SCR 6X6 - 20	Qty. 1	$126,500.00
SCR 6X6 - 18	Qty. 8	$1,004,923.00
SCR 6X4 - 16	Qty. 3	$358,712.00
Onsite Services	Qty. 27	$333,174.00

TOTAL ………………………………………………………………………….. $3,928,398.00

W.W. Williams RESERVES THE RIGHT TO CORRECT ERRORS OR OMISSIONS.

Price DOES NOT include the following:
Any Applicable Local, State, or Federal Taxes

Lead Times: Estimated delivery of this product is approximately **32 - 34 Weeks** from date of submittal approval and/or release for manufacturing. Please note that this is an estimate, and actual ship date could vary. In no event will we be responsible for any delay damages, liquidated damages, or any other late fees or penalties. If a specific ship date is required for this project, we must be notified in writing prior to date of order and we will accept or reject the order depending on all factors involved. We will not accept back charges or penalties unless we have agreed in writing to do so.

Terms:
Payment Schedule: **Net 30** based on the following invoice schedule:

- 10% Invoiced upon receipt of Purchase Order
- 50% Invoiced upon receipt of Release for Manufacturing
- 30% Invoiced upon Delivery of Equipment
- 10% Invoiced upon completion of Start-Up

With Approved Credit, Otherwise C.O.D. - A 1 ½% (18% APR) Finance Charge Will Be Applied to All Accounts Past Due. 90% OF JOB TOTAL MUST BE PAID *BEFORE* START-UP IS PERFORMED.
Terms and Conditions include those on the last page of this document.

Acceptable methods of payment include cash, check, ACH, wire, or debit card.

If you are a new customers, or need to update terms, to help expedite your order please fill out our Credit App available at credit@wwwilliams.com.

Thank you for the opportunity to provide this quote and support all of your power generation requirements.

Best regards,

Jordan Lockett

Power Generation Sales
The W.W. Williams Company, LLC

ELECTION TO PURCHASE OR LEASE (CHOOSE ONE):

☐ **PURCHASE - If a purchase order is written, we will also require that you sign and date this proposal in the following space provided. Please include this signed proposal with your purchase order. We will not order any equipment until you have submitted a credit application to W. W. Williams and it has been approved by W. W. Williams.**

DATE: _______________ ACCEPTED FIRM NAME: ________________________ BY: ________________________________

TERMS AND CONDITIONS

These Terms and Conditions apply to all sales transactions with The W.W. Williams Company, LLC, including quotations, purchase orders, service orders, sales orders, or similar documents:

1. **Terms Exclusive.** These Terms and Conditions and the applicable quotation, purchase order, service order, sales order or similar document constitute the complete, exclusive and final agreement (collectively, the "Agreement") of the buyer ("Buyer") and The W.W. Williams Company, LLC ("Williams"). All other additional or conflicting terms or conditions which may now or in the future appear on Buyer's acknowledgment, purchase order, or other similar document are expressly objected to by Williams without future notification and shall be null and void. These Terms and Conditions may only be modified, superseded or altered in writing signed by both parties. Buyer's acceptance of any performance by Williams shall be taken as Buyer's acceptance of these Terms and Conditions.

2. **Prices.** Prices are subject to change or withdrawal without notice. Unless otherwise stated in the Agreement, prices may be adjusted to and invoiced at Williams's price list in effect at the time of the shipment of goods or furnishing of the services. Unless otherwise stated in the Agreement, prices are exclusive of applicable taxes, excises, duties, quotation fees or other governmental impositions which Williams may be required to pay or collect on behalf of Buyer.

3. **Payment Terms; Security Interest.** Extensions of credit by Williams are subject to credit approval by Williams in its sole discretion, which may be modified or revoked by Williams at any time. Unless otherwise stated in the Agreement, payment shall be due and payable in full and without setoff within 15 days following delivery of the goods or completion of the services. Any payment not made when due shall be subject to a carrying charge of one and one-half percent (1 ½%) per month on the unpaid balance until paid in full. Buyer expressly grants to Williams a security interest in any goods, or a mechanic's or garage keeper's lien, as applicable, in respect of any services, to secure payment of the purchase price therefore and any other amounts or charges owed by Buyer to Williams. Buyer authorizes Williams (but Williams is not obligated) to file a financing statement or take such action as Williams deems advisable to evidence and perfect its security interest.

4. **Delivery; Force Majeure.** Unless otherwise stated in the Agreement, delivery of the goods, and services, if any, shall be F.O.B. point of shipment. Any delivery date specified is approximate only. Acceptance of shipment by a common carrier shall constitute tender of delivery. Upon tender of delivery, risk of loss shall pass to Buyer. Title shall pass to Buyer when the full price has been paid. Partial shipments may be made and payments therefore shall become due in accordance with the terms hereof as shipments are made and invoices rendered. If Williams is not able to meet the delivery date specified by reason of any force majeure event beyond Williams's control, including (but not limited to) war, governmental requests, restrictions or regulations, fire, flood, casualty, accident, or other acts of God, disease or illness, including but not limited to epidemic, pandemic, or quarantine, national or state declared emergency, strikes or other difficulties with employees, supplier delays, delay or inability to obtain goods, labor, equipment, material and service through Williams's usual sources, failure, refusal or delay of any carrier to transport materials, or any other similar event, Williams shall not be liable therefor and may, in its discretion without prior notice to Buyer, postpone the delivery date(s) under this Agreement for a time which is reasonable under all the circumstances. Acceptance of the goods or services shall constitute a waiver of all claims for damages.

5. **Standard Limited Warranty; Limitations of Liability.** The Williams Standard Limited Warranty and the limitations of liability contained therein, attached as Exhibit A hereto, shall apply to the purchase and sale of goods and services under this Agreement.

6. **Indemnification.** Buyer shall indemnify, defend, and hold harmless Williams, its directors, officers, employees and their respective affiliates against any claim, demand, complaint, liability, loss, cost, damage and/or expense (including attorneys' fees, costs and expenses of litigation and settlements) incurred by Williams arising out of or as a result of this Agreement, except to the extent caused by the negligence of Williams.

7. **Claims.** Unless otherwise stated in the Agreement, claims respecting the condition of goods, compliance with specifications, or any other matter affecting goods shipped or services provided to Buyer, must be made promptly and in no event later than twenty (20) days after receipt of the goods by Buyer or the furnishing of the services by Williams. Failure of Buyer to make a claim within such 20-day period shall be deemed an unqualified acceptance of the goods or services by Buyer. Buyer shall set aside, protect, and hold such goods (without charge to Williams) without further processing until Williams has an opportunity to inspect and advise of the disposition, if any, to be made of such goods. In no event shall any goods be returned, reworked, or scrapped by Buyer without the express written authorization of Williams.

8. **Default and Williams's Remedies.** If Buyer fails to make timely payment on any sale of goods or services from Williams to Buyer, Williams, in addition to any other remedies available to it, may at its option, (a) defer further shipment or services until such payments are made and satisfactory credit arrangements are reestablished or (b) cancel the balance of any order, and Buyer shall not have any cause of action or be entitled to any offset, counterclaim, or recoupment against Williams by reason of such action. In the event of Buyer's default, Williams may exercise any and all remedies set forth in this Agreement, any other agreement between the parties, and applicable law, all of which rights and remedies are cumulative.

9. **Collection Costs and Attorney Fees.** Buyer agrees to pay all of Williams's costs and expenses incurred in collecting payments due from Buyer (including without limitation reasonable attorney fees and costs and expenses of any collection agency).

10. **Return Policy**. Returns must be accompanied by this invoice and in the original, unopened box or packaging. A 15% restocking charge will be applied to all returned items. No returns on electrical items. No returns on special order items. No returns after 30 days from invoice date.

11. **Technical Assistance.** Unless otherwise stated in the Agreement: (a) any technical advice provided by Williams with respect to the use of goods or services furnished to Buyer shall be provided as a courtesy without charge and without warranty; (b) Williams assumes no obligation and disclaims all liability for any such advice or for any results occurring as a result of the application of such advice; and (c) Buyer shall have sole responsibility for selection and specification of the goods and services appropriate for the end use of such goods or services.

12. **Miscellaneous**. This Agreement will be governed by the laws of the State of Ohio. The exclusive venue for any dispute related to this Agreement shall be the federal and state courts located in Columbus, Ohio. If any of the provisions hereof shall be held invalid, illegal or unenforceable, the validity, legality and enforceability of the remaining provisions shall in no way be affected or impaired thereby. The individual rights and remedies of Williams reserved herein shall be cumulative and additional to any other or further remedies provided in law or equity. Waiver by Williams of performance or inaction with respect to Buyer's breach of any provision hereof, or failure of Williams to enforce any provision hereof which may establish a defense or limitation of liability, shall not be deemed a waiver of future compliance therewith or a course of performance modifying such provision, and such provision shall remain in full force and effect as written.

13. **Entire Agreement.** This Agreement, including without limitation the Terms and Conditions and any other document incorporated herein by reference, constitutes the sole and entire agreement between Buyer and Williams with respect to any order or sale of goods or furnishing of services to Buyer, superseding completely any prior or contemporaneous oral or written communications.

EXHIBIT A

The W.W. Williams Company, LLC

Standard Limited Warranty

Limited warranty for parts and equipment:

The sole warranty provided for any part or equipment sold by The W.W. Williams Company, LLC ("Williams") is to assign the warranty offered by the manufacturer or supplier to the Buyer. WILLIAMS MAKES NO REPRESENTATION OR WARRANTY TO THE EFFECTIVENESS OR EXTENT OF SUCH MANUFACTURER OR SUPPLIER WARRANTY. WILLIAMS EXPRESSLY DISCLAIMS ALL OTHER WARRANTIES, EXPRESS OR IMPLIED, INCLUDING, WITHOUT LIMITATION, ANY IMPLIED WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, and does not assume or authorize any other person to assume for it any liability in connection with the sale.

Limited warranty for services:

Williams warrants its workmanship for a period of ninety (90) days from the date the services are performed (the "Warranty Period"). This warranty covers defects in Williams's workmanship that are discovered during the Warranty Period. Buyer's sole remedy, and Williams's only liability, for Williams's breach of its service warranty shall be, at Williams's option, (i) reperforming the defective services; or (ii) refunding the purchase price paid for the defective services. WILLIAMS EXPRESSLY DISCLAIMS ALL OTHER WARRANTIES, EXPRESS OR IMPLIED, INCLUDING, WITHOUT LIMITATION, ANY IMPLIED WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, and does not assume or authorize any other person to assume for it any liability in connection with the sale.

Limitations of Liability:

IN NO EVENT SHALL WILLIAMS BE LIABLE FOR ANY PUNITIVE, INDIRECT, INCIDENTAL, CONSEQUENTIAL, SPECIAL OR UNKNOWN DAMAGES, INCLUDING BUT NOT LIMITED TO, LOSS OF PROPERTY OR EQUIPMENT, LOSS OF DATA, LOSS OF USE, LOSS OF TIME, LOSS OF REVENUE, LOSS OF PROFIT, OR LOSS OF INCOME, WHETHER THE DAMAGES BE IN CONTRACT OR TORT.

WILLIAMS'S TOTAL LIABILITY FOR ANY PARTS, EQUIPMENT, OR SERVICES SOLD SHALL NOT EXCEED THE AMOUNT PAID TO WILLIAMS FOR SUCH PARTS, EQUIPMENT, OR SERVICES CAUSING THE LIABILITY.

Appendix 4

Switch RACT Analysis

REASONABLY AVAILIBLE CONTROL TECHNOLOGY REVIEW

Switch / Las Vegas, NV

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1. EXECUTIVE SUMMARY

Switch, Ltd. (Switch) has been encouraged by Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ) to prepare and submit a Reasonably Available Control Technology (RACT) analysis for certain emission units operated at Switch's West Campus in Las Vegas, Nevada (the Facility). DAQ issued a revised Part 70 Operating Permit No. 16304 on September 12, 2022 for the Facility (the Permit).

DAQ requested that a RACT analysis be submitted by October 3, 2022 for emission units with a potential-to-emit (PTE) exceeding five tons per year (tpy) of oxides of nitrogen (NO_x) or volatile organic compounds (VOCs) at major sources of NO_x or VOCs, respectively, within Hydrographic Area (HA) 212. This request was triggered as a result of the proposed reclassification of hydrographic area 212 from marginal to moderate nonattainment for ozone.[1] The new classification would require HA 212 to achieve attainment by August 3, 2024, and require DAQ to establish emissions control requirements in its State Implementation Plan (SIP), including RACT requirements.[2] RACT should be considered as the lowest emissions an industrial source is allowed to emit through use of control technology that is reasonably available considering technological and economical feasibility.[3]

The Facility is currently a major source of NO_x (i.e., site-wide NO_x PTE is greater than 100 tpy). The Facility does not include any emission units at the Facility with PTE greater than five tpy of NO_x. However, per guidance from DAQ, Switch is proactively submitting this RACT analysis for the Facility.[4] The site-wide PTE is presented in Table 1-1 of this report.[5]

Table 1-1. Site-Wide PTE including Unconstructed Emission Units (tpy)

Pollutant	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP	GHG
Source Total	6.98	2.69	246.18	32.58	1.30	3.71	1.30	24,048.43

Per the August 1, 2022 DAQ RACT Stakeholder meeting, DAQ is requesting that the following information be submitted, as applicable:

- General Information, such as:
  - Confirmation of Major Source PTE (Potential to Emit)
  - List of emission units potentially subject to a RACT Requirement
  - Rated size or maximum capacity of each emission unit, and the type of fuel combusted or the types and quantities of materials processed or produced from the production process in which the emission unit is located
- RACT Specific Information, such as:

[1] 87 FR 43764.

[2] Per the August 1, 2022 Clark County DAQ 2015 Ozone NAAQ - Reasonably Available Control Technology (RACT) Requirements Presentation.

[3] Ibid.

[4] Email from Ted Lendis (DAQ) to Sean Keane (Trinity) on September 14, 2022.

[5] Site-wide PTE per the Permit.

- Information sources relied on to identify available control options
- Evaluation of technical feasibility
- Proposed RACT emission limitation or averaging approach
- Proposed testing, monitoring, and recordkeeping and reporting meeting periodic or CAM monitoring requirements.

Trinity has reviewed the technical feasibility of control methods with Switch for the diesel-fired emergency engines and fire pumps engines at the Facility and determined that complying with the applicable 40 CFR Part 60 Subpart IIII requirements, including emissions standards, for stationary compression ignition (CI) internal combustion emergency engines constitutes RACT for the diesel-fired emergency engines. Additionally, Facility's diesel-fired emergency engines currently comply with relevant RACT prohibitory rules of other air agencies. Therefore, there are no proposed changes to the emission limitations and testing, monitoring, and recordkeeping requirements contained in the Permit for the diesel-fired emergency engines. Section 2 contains a detailed RACT analysis and discussion.

2. REASONABLY ACHIEVABLE CONTROL TECHNOLOGY ASSESSMENT

A RACT evaluation consists of a technical and economic feasibility analysis for implementation of either passive or active methods for reducing emissions. Various options, including control devices and process changes are evaluated to determine their technical feasibility. Those that are deemed technically feasible are evaluated to determine their economic feasibility, which is based on the cost effectiveness of the reduction technique in terms of the cost per ton of pollutant controlled. The cost is the sum of the annualized capital cost and the annual operating cost. Those that exceed a certain threshold are deemed economically infeasible. The technically and economically feasible option that results in the largest decrease in emissions is deemed RACT. Trinity undertook an evaluation on Switch's behalf, and believes the current level of NO_x emissions from the emergency engine is considered RACT and no additional control technology is technically or economically feasible.

2.1 Technically Feasible Options

Trinity has evaluated RACT, on behalf of Switch, for all applicable diesel-fired emergency engines by determining what process changes and add-on emission controls are technically feasible for this specific type of equipment. Potential emission reduction measures were determined by a review of EPA's RACT/Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC). The following sections provide details on the assessment methodology utilized in preparing the RACT analysis for the diesel-fired emergency engines.

2.1.1 Characterization of Process Equipment

The cost and efficiency of NO_x reduction technology is dependent on the nature of the equipment in which the control device will be installed. Thus, it is important to classify the process equipment properly for the purposes of determining RACT. The process equipment consists of diesel-fired emergency engines and fire pump engines of various makes and models. Therefore, the diesel-fired emergency engines either are classified as Large Internal Combustion Engines (> 500 hp) or Small Internal Combustion Engines (< 500 hp) for purposes of the RBLC. Please refer to Table 1-1 to Table 1-6 of the Permit for a complete description of each diesel-fired emergency engine at the Facility.

2.1.2 Identification of Potential Control Technologies

Available NO_x control technologies are identified for each emission unit in question. The following methods are used to identify potential technologies: (1) researching the RBLC database; (2) surveying regulatory agencies; (3) drawing from previous engineering experience; (4) surveying air pollution control equipment vendors; and (5) surveying available literature.

2.1.2.1 RACT/BACT/LAER Clearinghouse (RBLC)

The RBLC, a database made available to the public through the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN), lists technologies and corresponding emission limits that have been approved by regulatory agencies in permit actions. These technologies are grouped into categories by industry and can be referenced in determining what emissions levels were proposed for similar types of emission units.

On behalf of Switch, Trinity has performed searches of the RBLC in September 2022 to identify the emission control technologies and emission levels that were determined by permitting authorities as RACT, BACT, or

LAER. Searches were performed for determinations within the past ten (10) years for emission sources comparable to those at Switch. The following categories were searched:

- Large Internal Combustion Engines (> 500 hp)
  - Fuel Oil (ASTM #1,2, includes kerosene, aviation, diesel fuel) (RBLC Code 17.110)
- Small Internal Combustion Engines (< 500 hp)
  - Fuel Oil (ASTM #1,2, includes kerosene, aviation, diesel fuel) (RBLC Code 17.210)

The following control technologies are technologically feasible based on the RBLC database search results.

- EPA Tier Certification
- Use of good combustion practices (GCP)

The RBLC search results are available in Appendix A.

2.1.2.2 EPA Tier Certification

Emergency engines are certified to comply with EPA Tier Emission Standards as outlined in 40 CFR Part 60 Subpart IIII for stationary CI internal combustion emergency engine or stationary fire pump engines, per the maximum engine power and model year.

2.1.2.3 Good Combustion Practices

The use of GCP at the Facility includes operating diesel-fired emergency engines to obtain a good air/fuel mixture in the combustion zone by maintaining overall excess oxygen levels high enough to complete combustion while maximizing thermal efficiency and by providing sufficient residence time to complete combustion. GCP also includes operating the equipment in accordance with the manufacturer's recommended settings and preventative maintenance schedules. Following good combustion practices is in the interest of engine operators from an efficiency and reliability perspective.

2.1.2.4 Technical Feasibility Determination – Diesel-Fired Emergency Engines

The diesel-fired emergency engines are assumed to use GCP as they meet manufacturer specifications and comply with the applicable 40 CFR Part 60 Subpart IIII requirements, including emissions standards per the maximum engine power and model year, for stationary CI internal combustion emergency engines. The use of GCP is technically feasible and use of an EPA Tier certified engine has been demonstrated in practice for those emergency engines subject to 40 CFR Part 60 Subpart IIII requirements (i.e., the emergency engines at the Facility).

Additionally, in its 2010 MACT (Maximum Achievable Control Technology) /GACT (Generally Available Control Technology) evaluation for RICE (Reciprocating Internal Combustion Engines), EPA concluded for emergency RICE: "Because these engines are typically used only a few numbers of hours per year, the costs of emission control are not warranted when compared to the emission reductions that would be achieved." Based on EPA's assessment and the fact that the RBLC contains no records of add on controls (i.e., SCR) installation on emergency-use RICE, add on controls are eliminated from consideration as RACT.[6]

[6] U.S. EPA, Memorandum: Response to Public Comments on Proposed National Emission Standards for Hazardous Air Pollutants for Existing Stationary Reciprocating Internal Combustion Engines Located at Area Sources of Hazardous Air Pollutant Emissions or Have a Site Rating Less Than or Equal to 500 Brake HP Located at Major Sources of Hazardous Air Pollutant Emissions, August 10, 2010, p. 172-173. (EPA-HQ-OAR-2008-0708).

Furthermore, Trinity has reviewed the current RACT requirements for emergency engines in other agency jurisdictions, on behalf of Switch. For example, San Joaquin Valley Air Pollution Control District (SJVAPCD) Rule 4702 limits emissions of NO_x from internal combustion engines greater than 25 brake horsepower (BHP). [7] Pursuant to SJVAPCD Rule 4702 Section 4.2, emergency engines comply with the Rule by:

- Limiting annual operation and only operating for specific purposes (e.g., testing, maintenance, and emergency purposes),
- Utilizing a non-resettable hour meter,
- Operating and maintaining the engine as recommended by the engine manufacturer, and
- Maintaining records of operation.

Similarly, South Coast Air Quality Management District (SCAQMD) Rule 1110-2 limits NO_x emissions from engines. Per Subsection (i) of that Rule, emergency engines are not subject to the emission standards of the Rule (and associated requirements).[8] Trinity completed an assessment on behalf of Switch, and concludes that the current Permit requirements for the Facility's diesel-fired emergency engines are consistent with the RACT prohibitory requirements of other jurisdictions, such as SJVAPCD and SCAMQD. As such, the installation of add on controls or implementation of additional emission standards is eliminated from consideration as RACT.

2.1.3 Selection of NO_x RACT for the Diesel-Fired Emergency Engines

As discussed in Section 2.1.2.4, the diesel-fired emergency engines use GCP as they meet manufacturer specifications and are certified to comply with the applicable emission standards as outlined in 40 CFR Part 60 Subpart IIII for stationary CI internal combustion emergency engine, per the maximum engine power and model year. As discussed previously, the installation of add-on controls to the existing emergency engines is not feasible per EPA and other agencies' RACT prohibitory rules (e.g., SCAQMD and SJVAPCD) do not require compliance with specific NO_x emission standards for emergency engines. Therefore, the use of GCP and compliance with applicable 40 CFR Part 60 Subpart IIII requirements, such as emission standards, is technically feasible and is selected as meeting RACT for all of the diesel-fired emergency engines.

Switch intends to maintain the current emission limits for NO_x as contained in the Permit for each of the affected diesel emergency engines. Switch will utilize the existing Permit conditions to monitor compliance with the NO_x emission limits contained in the Permit.

[7] SJVAPCD Rule 4702, Amended August 19, 2021. https://www.valleyair.org/rules/currntrules/r4702.pdf

[8] SCAQMD Rule 1110-2, Amended November 1, 2019. http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1110-2.pdf?sfvrsn=4

APPENDIX A: SUMMARY OF RBLC

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
AK-0076	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT01	1382	211111	8/20/2012	Combustion of Diesel by ICEs	17.11	ULSD	1750	kW	NO_x	10102		6.4	G/KW-H	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	1382	211111	1/23/2015	Remote Incinerator Generator Engine	21.4	Ultra Low Sulfur Diesel	102	hp	NO_x	10102		3	LB/TON	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	1382	211111	1/23/2015	Emergency Camp Generators	17.11	Ultra Low Sulfur Diesel	2695	hp	NO_x	10102		4.8	GRAMS/HP-H	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	1382	211111	1/23/2015	Airstrip Generator Engine	17.21	Ultra Low Sulfur Diesel	490	hp	NO_x	10102		4.8	GRAMS/HP-H	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	1382	211111	1/23/2015	Agitator Generator Engine	17.21	Ultra Low Sulfur Diesel	98	hp	NO_x	10102		5.6	GRAMS/HP-H	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	1382	211111	1/23/2015	Incinerator Generator Engine	17.21	Ultra Low Sulfur Diesel	102	hp	NO_x	10102-44-0		4.9	GRAMS/HP-H	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	1382	211111	1/23/2015	Fine Water Pumps	17.11	Ultra Low Sulfur Diesel	610	hp	NO_x	10102		3	GRAMS/HP-H	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	1382	211111	1/23/2015	Bulk Tank Generator Engines	17.11	Ultra Low Sulfur Diesel	891	hp	NO_x	10102		4.8	GRAMS/HP-H	BACT-PSD
AK-0084	DONLIN GOLD PROJECT	AQ0934CPT01	1041	212221	6/30/2017	Black Start and Emergency Internal Combustion Engines	17.11	Diesel	1500	kWe	NO_x	10102	Good Combustion Practices	8	G/KW-HR	BACT-PSD
AK-0084	DONLIN GOLD PROJECT	AQ0934CPT01	1041	212221	6/30/2017	Fire Pump Diesel Internal Combustion Engines	17.21	Diesel	252	hp	NO_x	10102	Good Combustion Practices	3.7	G/KW-HR	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
AK-0085	GAS TREATMENT PLANT	AQ1524CPT01	4922	486210	8/13/2020	One (1) Black Start Generator Engine	17.11	ULSD	186.6	gph	NO_x	10102	Good combustion practices, limit operation to 500 hours per year.	3.3	G/HP-HR	BACT-PSD
AK-0085	GAS TREATMENT PLANT	AQ1524CPT01	4922	486210	8/13/2020	Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators	17.21	ULSD	19.4	gph	NO_x	10102	Good combustion practices, limit operation to 500 hours per year per engine	3.6	G/HP-HR	BACT-PSD
AK-0088	LIQUEFACTION PLANT	AQ1539CPT01	4922	488999	7/7/2022	Diesel Fire Pump Engine	17.11	Diesel	27.9	Gal/hr	NO_x	10102	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII	3.6	G/HP-HR	BACT-PSD
AK-0088	LIQUEFACTION PLANT	AQ1539CPT01	4922	488999	7/7/2022	Auxiliary Air Compressor Engine	17.21	Diesel	14.6	Gal/hr	NO_x	10102	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII	0.45	G/HP-HR	BACT-PSD
AL-0301	NUCOR STEEL TUSCALOOSA, INC.	413-0033-X014 - X020	3312	331111	7/22/2014	DIESEL FIRED EMERGENCY GENERATOR	17.11	DIESEL	800	HP	NO_x	10102		0.015	LB/HP-H	BACT-PSD
*AL-0318	TALLADEGA SAWMILL	309-0075	2421	321113	12/18/2017	250 Hp Emergency CI, Diesel-fired RICE	17.11	Diesel	0		NO_x	10102		0		N/A
AL-0328	PLANT BARRY	503-1001	4911	221112	11/9/2020	Diesel Emergency Engines	17.11	Diesel	0		NO_x	10102		3	GR/BHP-HR	BACT-PSD
AR-0161	SUN BIO MATERIAL COMPANY	2384-AOP-R0	2611	322110	9/23/2019	Emergency Engines	17.11	Diesel	0		NO_x	10102	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.4	G/KW-H	BACT-PSD
AR-0163	BIG RIVER STEEL LLC	2305-AOP-R6	3312	331111	6/9/2019	Emergency Engines	17.11	Diesel	0		NO_x	10102	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	4.86	G/KW-HR	BACT-PSD
CA-1219	CITY OF SAN DIEGO PUD (PUMP STATION 1)	2012--APP-002009	4952	221320	7/9/2012	IC engine	17.11	diesel	2722	bhp	NO_x	10102	Tier 2 certified engine and 50 hr/yr for M&T	4	G/B-HP-H	OTHER CASE-BY-CASE
DC-0009	BLUE PLAINS ADVANCED WASTEWATER TREATEMENT PLANT	6372-A1	4952	221320	3/15/2012	Diesel Emergency Generator	17.11	Ultra-low Sulfur Diesel	2682	hp	NO_x	10102		31.87	LB/HR	LAER
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Main Propulsion Engines - Development Driller 1	17.11	Diesel	0		NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines, and additional enhanced work practice standards including an engine performance management system, positive crankcase ventilation, turbocharger with aftercooler, and high pressure fuel injection with aftercooler.	12.1	G/KW-H	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Main Propulsion Engines - C.R. Luigs	17.11	Diesel	5875	hp	NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines, and additional enhanced work practice standards including an engine performance management system, positive crankcase ventilation, turbocharger with aftercooler, and high pressure fuel injection with aftercooler.	18.1	G/KW-H	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Wireline Unit Engines - C.R. Luigs	17.21	diesel	300	hp	NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines, use of low sulfur diesel fuel, turbocharger with aftercooler, high pressure fuel injection with aftercooler	8.92	T/12MO ROLLING TOTAL	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Fast Rescue Craft Diesel Engine - Development Driller 1	17.21	Diesel	142	hp	NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines, use of low sulfur diesel fuel, and turbocharger	0		BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Life Boat Diesel Engines - Development Driller 1	17.21	Diesel	110	hp	NO_x	10102-44-0	Use of good combustion practices based on the current manufacturerâ's specifications for these engines and use of low sulfur diesel fuel	0		BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Port and Stb Fwd and Aft Crane Diesel Engines - C.R. Luigs	17.21	diesel	305	HP	NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with aftercooler, high pressure fuel injection with aftercooler	82.83	T/12MO ROLLING TOTAL	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Fast Rescue Craft Diesel Engine - C.R. Luigs	17.11	diesel	142	hp	NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines and use of low sulfur diesel fuel	0		BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Seismic Operations Diesel Engines - Development Driller 1	17.21	Diesel	415	hp	NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines, use of low sulfur diesel fuel, and turbocharger	3.54	TONS	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Life Boat Diesel Engines - C.R. Luigs	17.21	diesel	39	hp	NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines, use of low sulfur diesel fuel	0		BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Emergency Generator Diesel Engine - Development Driller 1	17.11	Diesel	2229	hp	NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with aftercooler, high pressure fuel injection with aftercooler	1.6	T/12MO ROLLING TOTAL	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Cementing and Nitrogen Pump Diesel Engines - Development Driller 1	17.21	Diesel	0		NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger, and high pressure fuel injection with aftercooler	9.5	T/12MO ROLLING TOTAL	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Wireline Unit Diesel Engines - Development Driller 1	17.21	Diesel	0		NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines, use of low sulfur diesel fuel, turbocharger with aftercooler, high pressure fuel injection with aftercooler	8.92	TONS	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Black Start Air Compressor - C.R. Luigs	17.21	diesel	6	hp	NO_x	10102-44-0	Use of good combustion practices based on the current manufacturerâ's specifications for the engine and the use of low sulfur diesel fuel	0		BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Emergency Generator Diesel Engine - C.R. Luigs	17.11	diesel	2064	hp	NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with aftercooler, high pressure fuel injection with aftercooler	1.49	T/12MO ROLLING TOTAL	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Cementing and Nitrogen Pump Diesel Engines - C.R. Luigs	17.21	diesel	0		NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger, and high pressure fuel injection with aftercooler	8.69	T/12MO ROLLING TOTAL	BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	1381	211111	9/16/2014	Main Propulsion Generator Diesel Engines	17.11	Diesel	9910	hp	NO_x	10102	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	12.7	G/KW-H	BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	1381	211111	9/16/2014	Diesel Powered Forklift Engine	17.21	Diesel	30	hp	NO_x	10102	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine	0		BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	1381	211111	9/16/2014	Wireline Diesel Engines	17.21	Diesel	0		NO_x	10102	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine and with turbocharger, aftercooler, and high injection pressure	0		BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	1381	211111	9/16/2014	Water Blasting Diesel Engine	17.21	Diesel	208	hp	NO_x	10102	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine and with turbocharger, aftercooler, and high injection pressure	0		BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	1381	211111	9/16/2014	Well Evaluation Diesel Engine	17.21	Diesel	140	hp	NO_x	10102	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine	0		BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	1381	211111	9/16/2014	Fast Rescue Craft Diesel Engine	17.21	Diesel	230	hp	NO_x	10102	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine and with turbocharger, aftercooler, and high injection pressure	0		BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	1381	211111	9/16/2014	Escape Capsule Diesel Engine	17.21	Diesel	39	hp	NO_x	10102	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine	0		BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	1381	211111	9/16/2014	Emergency Diesel Engine	17.11	Diesel	3300	hp	NO_x	10102	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	0		BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	1381	211111	9/16/2014	Remotely Operated Vehicle Emergency Generator	17.21	Diesel	427	hp	NO_x	10102	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	0		BACT-PSD
FL-0348	MURPHY EXPLORATION & PRODUCTION CO.	OCS-EPA-R4009	1381	213111	5/15/2012	Main Propulsion Generators	17.21	Diesel	4425	hp	NO_x	10102	Use of engine with turbo charger with after cooler, an enhanced work practice power management, NOx emissions maintenance system, and good combustion and maintenance practices based on the current manufacturerâ's specifications for each engine	26	G/KW-H	BACT-PSD
FL-0348	MURPHY EXPLORATION & PRODUCTION CO.	OCS-EPA-R4009	1381	213111	5/15/2012	Drill Floor and Crew Quarters Electrical Generators	17.11	Diesel	6789	hp	NO_x	10102	Use of engine with turbo charger with after cooler, an enhanced work practice power management, NOx emissions maintenance system, and good combustion and maintenance practices based on the current manufacturerâ's specifications for each engine.	26	G/KW-H	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
FL-0348	MURPHY EXPLORATION & PRODUCTION CO.	OCS-EPA-R4009	1381	213111	5/15/2012	Emergency Electrical Generator	17.11	Diesel	1100	hp	NO_x	10102	Use of good combustion and maintenance practices based on the current manufacturerâ's specifications for this engine.	0.22	TONS	BACT-PSD
FL-0350	ANADARKO PETROLEUM, INC DIAMOND BLACKHAWK DRILLING PROJECT	OCS-EPA-R4019	1381	213111	12/31/2014	Main Propulsion Generator Engines	17.11	Diesel	0		NO_x	10102	Use of good combustion practices based on the most recent manufacturerâ's specifications issued for these engines at the time that the engines are operating under this permit	0		BACT-PSD
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	1010524-001-AC	4911	221112	7/27/2018	1,500 kW Emergency Diesel Generator	17.11	ULSD	14.82	MMBtu/hour	NO_x	10102	Operate and maintain the engine according to the manufacturer's written instructions	6.4	G/KW-HOUR	BACT-PSD
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	1010524-001-AC	4911	221112	7/27/2018	Emergency Fire Pump Engine (347 HP)	17.21	ULSD	8700	gal/year	NO_x	10102	Operate and maintain the engine according to the manufacturer's written instructions	4	G/KW-HR	BACT-PSD
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	1010524-003-AC (PSD-FL-444A)	4911	221112	6/7/2021	1,500 kW Emergency Diesel Generator	17.11	ULSD	14.82	MMBtu/hour	NO_x	10102		6.4	G/KW-HOUR	BACT-PSD
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	1010524-003-AC (PSD-FL-444A)	4911	221112	6/7/2021	Emergency Fire Pump Engine (347 HP)	17.21	ULSD	2.46	MMBtu/hour	NO_x	10102		4	G/KW-HOUR	BACT-PSD
IA-0105	IOWA FERTILIZER COMPANY	12-219	2873	325311	10/26/2012	Emergency Generator	17.11	diesel fuel	142	GAL/H	NO_x	10102	good combustion practices	6	G/KW-H	BACT-PSD
IA-0105	IOWA FERTILIZER COMPANY	12-219	2873	325311	10/26/2012	Fire Pump	17.21	diesel fuel	14	GAL/H	NO_x	10102	good combustion practices	3.75	G/KW-H	BACT-PSD
IL-0114	CRONUS CHEMICALS, LLC	13060007	2873	325311	9/5/2014	Emergency Generator	17.11	distillate fuel oil	3755	HP	NO_x	10102	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	0.67	G/KW-H	BACT-PSD
IL-0114	CRONUS CHEMICALS, LLC	13060007	2873	325311	9/5/2014	Firewater Pump Engine	17.21	distillate fuel oil	373	hp	NO_x	10102	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	3.5	G/KW-H	BACT-PSD
IL-0129	CPV THREE RIVERS ENERGY CENTER	16060032	4911	221112	7/30/2018	Emergency Engines	17.11	Ultra-low sulfur diesel	0		NO_x	10102		0		LAER
IL-0129	CPV THREE RIVERS ENERGY CENTER	16060032	4911	221112	7/30/2018	Firewater Pump Engine	17.21	Ultra-low sulfur diesel	0		NO_x	10102		0		LAER
IL-0130	JACKSON ENERGY CENTER	17040013	4911	221112	12/31/2018	Firewater Pump Engine	17.21	Ultra-Low Sulfur Diesel	420	horsepower	NO_x	10102		4	G/KW-HR	LAER
IL-0130	JACKSON ENERGY CENTER	17040013	4911	221112	12/31/2018	Emergency Engine	17.11	Ultra-Low Sulfur Diesel	1500	kW	NO_x	10102		6.4	G/KW-HR	LAER
*IL-0133	LINCOLN LAND ENERGY CENTER	18040008	4911	221112	7/29/2022	Emergency Engines	17.11	Ultra-Low Sulfur Diesel	1250	kW	NO_x	10102		6.4	GRAMS	BACT-PSD
*IL-0133	LINCOLN LAND ENERGY CENTER	18040008	4911	221112	7/29/2022	Fire Water Pump Engine	17.21	Ultra-Low Sulfur Diesel	320	horsepower	NO_x	10102		4	GRAMS	BACT-PSD
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	141-31003-00579	4911	221112	12/3/2012	TWO (2) FIREWATER PUMP DIESEL ENGINES	17.21	DIESEL	371	BHP, EACH	NO_x	10102	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	3	G/HP-H	BACT-PSD
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	141-31003-00579	4911	221112	12/3/2012	TWO (2) EMERGENCY DIESEL GENERATORS	17.11	DIESEL	1006	HP EACH	NO_x	10102	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	4.8	G/HP-H	BACT-PSD
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	141-31003-00579	4911	221112	12/3/2012	EMERGENCY DIESEL GENERATOR	17.11	DIESEL	2012	HP	NO_x	10102	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	4.8	G/HP-H	BACT-PSD
IN-0166	INDIANA GASIFICATION, LLC	T147-30464-00060	4925	221210	6/27/2012	TWO (2) EMERGENCY GENERATORS	17.11	DIESEL	1341	HORSEPOWER, EACH	NO_x	10102	GOOD COMBUSTION PRACTICES AND LIMITED HOURS OF NON-EMERGENCY OPERATION	0		BACT-PSD
IN-0166	INDIANA GASIFICATION, LLC	T147-30464-00060	4925	221210	6/27/2012	THREE (3) FIREWATER PUMP ENGINES	17.11	DIESEL	575	HORSEPOWER, EACH	NO_x	10102	GOOD COMBUSTION PRACTICES AND LIMITED HOURS OF NON-EMERGENCY OPERATION	0		BACT-PSD
IN-0173	MIDWEST FERTILIZER CORPORATION	129-33576-00059	2873	325311	6/4/2014	DIESEL FIRED EMERGENCY GENERATOR	17.11	NO. 2, DIESEL	3600	BHP	NO_x	10102	GOOD COMBUSTION PRACTICES	4.46	G/BHP-H	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
IN-0173	MIDWEST FERTILIZER CORPORATION	129-33576-00059	2873	325311	6/4/2014	RAW WATER PUMP	17.21	DIESEL, NO. 2	500	HP	NO_x	10102	GOOD COMBUSTION PRACTICES	2.83	G/BHP-H	BACT-PSD
IN-0179	OHIO VALLEY RESOURCES, LLC	147-32322-00062	2873	325311	9/25/2013	DIESEL-FIRED EMERGENCY GENERATOR	17.11	NO. 2 FUEL OIL	4690	B-HP	NO_x	10102	GOOD COMBUSTION PRACTICES	4.46	G/B-HP-H	BACT-PSD
IN-0179	OHIO VALLEY RESOURCES, LLC	147-32322-00062	2873	325311	9/25/2013	DIESEL-FIRED EMERGENCY WATER PUMP	17.21	NO. 2 FUEL OIL	481	BHP	NO_x	10102	GOOD COMBUSTION PRACTICES	2.86	G/B-HP-H	BACT-PSD
IN-0180	MIDWEST FERTILIZER CORPORATION	129-33576-00059	2873	325311	6/4/2014	DIESEL FIRED EMERGENCY GENERATOR	17.11	NO. 2, DIESEL	3600	BHP	NO_x	10102	GOOD COMBUSTION PRACTICES	4.46	G/B-HP-H	BACT-PSD
IN-0180	MIDWEST FERTILIZER CORPORATION	129-33576-00059	2873	325311	6/4/2014	RAW WATER PUMP	17.21	DIESEL, NO. 2	500	HP	NO_x	10102	GOOD COMBUSTION PRACTICES	2.83	G/B-HP-H	BACT-PSD
IN-0185	MAG PELLET LLC	181-33965-00054	1011	212210	4/24/2014	DIESEL FIRE PUMP	17.11	DIESEL	300	HP	NO_x	10102		3	G/HP-H	BACT-PSD
IN-0263	MIDWEST FERTILIZER COMPANY LLC	129-36943-00059	2873	325311	3/23/2017	EMERGENCY GENERATORS (EU014A AND EU-014B)	17.11	DISTILLATE OIL	3600	HP EACH	NO_x	10102	GOOD COMBUSTION PRACTICES	4.42	G/HP-H EACH	BACT-PSD
IN-0317	RIVERVIEW ENERGY CORPORATION	T147-39554-00065	2911	324110	6/11/2019	Emergency generator EU-6006	17.11	Diesel	2800	HP	NO_x	10102	Tier II diesel engine	6.4	G/KWH	BACT-PSD
IN-0317	RIVERVIEW ENERGY CORPORATION	T147-39554-00065	2911	324110	6/11/2019	Emergency fire pump EU-6008	17.11	Diesel	750	HP	NO_x	10102	Engine that complies with Table 4 to Subpart IIII of Part 60	4	G/KWH	BACT-PSD
IN-0324	MIDWEST FERTILIZER COMPANY LLC	129-44510-00059	2873	325311	5/6/2022	emergency generator EU 014a	17.11	distillate oil	3600	HP	NO_x	10102		4.42	G/HP-HR	BACT-PSD
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	C-10656	4911	221112	3/18/2013	Caterpillar C18DITA Diesel Engine Generator	17.11	No. 2 Distillate Fuel Oil	900	BHP	NO_x	10102	utilize efficient combustion/design technology	14	LB/HR	BACT-PSD
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	C-10656	4911	221112	3/18/2013	Cummins 6BTA 5.9F-1 Diesel Engine Fire Pump	17.21	No. 2 Fuel Oil	182	BHP	NO_x	10102	utilize efficient combustion/design technology	2	LB/HR	BACT-PSD
KY-0110	NUCOR STEEL BRANDENBURG	V-20-001	3312	331111	7/23/2020	EP 10-02 - North Water System Emergency Generator	17.11	Diesel	2922	HP	NO_x	10102	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	BACT-PSD
KY-0110	NUCOR STEEL BRANDENBURG	V-20-001	3312	331111	7/23/2020	EP 10-03 - South Water System Emergency Generator	17.11	Diesel	2922	HP	NO_x	10102	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	BACT-PSD
KY-0110	NUCOR STEEL BRANDENBURG	V-20-001	3312	331111	7/23/2020	EP 10-04 - Emergency Fire Water Pump	17.11	Diesel	920	HP	NO_x	10102	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	BACT-PSD
KY-0110	NUCOR STEEL BRANDENBURG	V-20-001	3312	331111	7/23/2020	EP 11-01 - Melt Shop Emergency Generator	17.21	Diesel	260	HP	NO_x	10102	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.98	G/HP-HR	BACT-PSD
KY-0110	NUCOR STEEL BRANDENBURG	V-20-001	3312	331111	7/23/2020	EP 11-02 - Reheat Furnace Emergency Generator	17.21	Diesel	190	HP	NO_x	10102	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.98	G/HP-HR	BACT-PSD
KY-0110	NUCOR STEEL BRANDENBURG	V-20-001	3312	331111	7/23/2020	EP 10-07 - Air Separation Plant Emergency Generator	17.11	Diesel	700	HP	NO_x	10102	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	BACT-PSD
KY-0110	NUCOR STEEL BRANDENBURG	V-20-001	3312	331111	7/23/2020	EP 10-01 - Caster Emergency Generator	17.11	Diesel	2922	HP	NO_x	10102	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	BACT-PSD
KY-0110	NUCOR STEEL BRANDENBURG	V-20-001	3312	331111	7/23/2020	EP 11-03 - Rolling Mill Emergency Generator	17.21	Diesel	440	HP	NO_x	10102	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.98	G/HP-HR	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
KY-0110	NUCOR STEEL BRANDENBURG	V-20-001	3312	331111	7/23/2020	EP 11-04 - IT Emergency Generator	17.21	Diesel	190	HP	NO_x	10102	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.98	G/HP-HR	BACT-PSD
KY-0110	NUCOR STEEL BRANDENBURG	V-20-001	3312	331111	7/23/2020	EP 11-05 - Radio Tower Emergency Generator	17.21	Diesel	61	HP	NO_x	10102	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	3.5	G/HP-HR	BACT-PSD
KY-0115	NUCOR STEEL GALLATIN, LLC	V-20-015	3316	331111	4/19/2021	New Pumphouse (XB13) Emergency Generator #1 (EP 08-05)	17.11	Diesel	2922	HP	NO_x	10102	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0		BACT-PSD
KY-0115	NUCOR STEEL GALLATIN, LLC	V-20-015	3316	331111	4/19/2021	Tunnel Furnace Emergency Generator (EP 08-06)	17.11	Diesel	2937	HP	NO_x	10102	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0		BACT-PSD
KY-0115	NUCOR STEEL GALLATIN, LLC	V-20-015	3316	331111	4/19/2021	Caster B Emergency Generator (EP 08-07)	17.11	Diesel	2937	HP	NO_x	10102	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0		BACT-PSD
KY-0115	NUCOR STEEL GALLATIN, LLC	V-20-015	3316	331111	4/19/2021	Air Separation Unit Emergency Generator (EP 08-08)	17.11	Diesel	700	HP	NO_x	10102	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0		BACT-PSD
KY-0115	NUCOR STEEL GALLATIN, LLC	V-20-015	3316	331111	4/19/2021	Cold Mill Complex Emergency Generator (EP 09-05)	17.21	Diesel	350	HP	NO_x	10102	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0		BACT-PSD
LA-0292	HOLBROOK COMPRESSOR STATION	PSD-LA-769(M-1)	4922	486210	1/22/2016	Emergency Generators No. 1 & No. 2	17.11	Diesel	1341	HP	NO_x	10102	Good equipment design, proper combustion techniques, use of low sulfur fuel, and compliance with 40 CFR 60 Subpart IIII	14.16	LB/HR	BACT-PSD
LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	PSD-LA-779	2821	325211	5/23/2014	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, & 1202)	17.11	Diesel	2682	HP	NO_x	10102	Compliance with 40 CFR 60 Subpart IIII; operating the engine in accordance with the engine manufacturerâ's instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage.	27.37	LB/HR	BACT-PSD
LA-0305	LAKE CHARLES METHANOL FACILITY	PSD-LA-803(M1)	2869	325199	6/30/2016	Diesel Engines (Emergency)	17.11	Diesel	4023	hp	NO_x	10102	Complying with 40 CFR 60 Subpart IIII	0		BACT-PSD
LA-0307	MAGNOLIA LNG FACILITY	PSD-LA-792	4922	221210	3/21/2016	Diesel Engines	17.11	Diesel	0		NO_x	10102	good combustion practices, Use ultra low sulfur diesel, and comply with 40 CFR 60 Subpart IIII	0		BACT-PSD
LA-0308	MORGAN CITY POWER PLANT	PSD-LA-767	4911	221112	9/26/2013	2000 KW Diesel Fired Emergency Generator Engine	17.11	Diesel	20.4	MMBTU/hr	NO_x	10102	Good combustion and maintenance practices, and compliance with NSPS 40 CFR 60 Subpart IIII	33.07	LB/H	BACT-PSD
LA-0308	MORGAN CITY POWER PLANT	PSD-LA-767	4911	221112	9/26/2013	380 HP Diesel Fired Pump Engine	17.21	Diesel	2.3	MMBTU/hr	NO_x	10102	Good combustion and maintenance practices, and compliance with NSPS 40 CFR 60 Subpart IIII	2.92	LB/H	BACT-PSD
LA-0309	BENTELER STEEL TUBE FACILITY	PSD-LA-774(M1)	3312	331111	6/4/2015	Firewater Pump Engines	17.21	Diesel	288	hp (each)	NO_x	10102	Complying with 40 CFR 60 Subpart IIII	3	G/BHP-HR	BACT-PSD
LA-0309	BENTELER STEEL TUBE FACILITY	PSD-LA-774(M1)	3312	331111	6/4/2015	Emergency Generator Engines	17.11	Diesel	2922	hp (each)	NO_x	10102	Complying with 40 CFR 60 Subpart IIII	6.4	G/KW-HR	BACT-PSD
*LA-0312	ST. JAMES METHANOL PLANT	PSD-LA-780(M-1)	2869	325998	6/30/2017	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	17.11	Diesel	650	horsepower	NO_x	10102	Compliance with NSPS Subpart IIII	6.6	LB/HR	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
*LA-0312	ST. JAMES METHANOL PLANT	PSD-LA-780(M-1)	2869	325998	6/30/2017	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	17.11	Diesel	1474	horsepower	NO_x	10102	Compliance with NSPS Subpart IIII	19.23	LB/HR	BACT-PSD
LA-0313	ST. CHARLES POWER STATION	PSD-LA-804	4911	221112	8/31/2016	SCPS Emergency Diesel Generator 1	17.11	Diesel	2584	HP	NO_x	10102	Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel).	27.34	LB/H	BACT-PSD
LA-0313	ST. CHARLES POWER STATION	PSD-LA-804	4911	221112	8/31/2016	SCPS Emergency Diesel Firewater Pump 1	17.21	Diesel	282	HP	NO_x	10102	Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel).	1.87	LB/H	BACT-PSD
*LA-0315	G2G PLANT	PSD-LA-781	2869	325110	5/23/2014	Emergency Diesel Generator 1	17.11	Diesel	5364	HP	NO_x	10102	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	52.58	LB/H	BACT-PSD
*LA-0315	G2G PLANT	PSD-LA-781	2869	325110	5/23/2014	Emergency Diesel Generator 2	17.11	Diesel	5364	HP	NO_x	10102	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	52.58	LB/H	BACT-PSD
*LA-0315	G2G PLANT	PSD-LA-781	2869	325110	5/23/2014	Fire Pump Diesel Engine 1	17.11	Diesel	751	HP	NO_x	10102	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.6	LB/H	BACT-PSD
*LA-0315	G2G PLANT	PSD-LA-781	2869	325110	5/23/2014	Fire Pump Diesel Engine 2	17.11	Diesel	751	HP	NO_x	10102	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.6	LB/H	BACT-PSD
LA-0316	CAMERON LNG FACILITY	PSD-LA-766(M3)	4922	221210	2/17/2017	firewater pump engines (8 units)	17.21	diesel	460	hp	NO_x	10102-44-0	Complying with 40 CFR 60 Subpart IIII	0		BACT-PSD
LA-0316	CAMERON LNG FACILITY	PSD-LA-766(M3)	4922	221210	2/17/2017	emergency generator engines (6 units)	17.11	diesel	3353	hp	NO_x	10102	Complying with 40 CFR 60 Subpart IIII	0		BACT-PSD
LA-0317	METHANEX - GEISMAR METHANOL PLANT	PSD-LA-761(M4)	2869	325199	12/22/2016	Emergency Generator Engines (4 units)	17.11	Diesel	0		NO_x	10102	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	0		BACT-PSD
LA-0317	METHANEX - GEISMAR METHANOL PLANT	PSD-LA-761(M4)	2869	325199	12/22/2016	Firewater pump Engines (4 units)	17.11	diesel	896	hp (each)	NO_x	10102	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	0		BACT-PSD
LA-0323	MONSANTO LULING PLANT	PSD-LA-890	2879	325320	1/9/2017	Fire Water Diesel Pump No. 3 Engine	17.11	Diesel Fuel	600	hp	NO_x	10102	Proper operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII	0		BACT-PSD
LA-0323	MONSANTO LULING PLANT	PSD-LA-890	2879	325320	1/9/2017	Fire Water Diesel Pump No. 4 Engine	17.11	Diesel Fuel	600	hp	NO_x	10102	Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII	0		BACT-PSD
LA-0323	MONSANTO LULING PLANT	PSD-LA-890	2879	325320	1/9/2017	Standby Generator No. 9 Engine	17.21	Diesel Fuel	400	hp	NO_x	10102	Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII	0		BACT-PSD
LA-0331	CALCASIEU PASS LNG PROJECT	PDS-LA-805	4925	221210	9/21/2018	Firewater Pumps	17.11	Diesel Fuel	634	kW	NO_x	10102	Good Combustion and Operating Practices.	3.1	G/HP-H	BACT-PSD
LA-0331	CALCASIEU PASS LNG PROJECT	PDS-LA-805	4925	221210	9/21/2018	Large Emergency Engines (>50kW)	17.11	Diesel Fuel	5364	HP	NO_x	10102	Good Combustion and Operating Practices	5.6	G/KW-H	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
LA-0364	FG LA COMPLEX	PSD-LA-812	2869	325110	1/6/2020	Emergency Generator Diesel Engines	17.11	Diesel Fuel	550	hp	NO_x	10102	Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	0		BACT-PSD
LA-0364	FG LA COMPLEX	PSD-LA-812	2869	325110	1/6/2020	Emergency Fire Water Pumps	17.11	Diesel Fuel	550	hp	NO_x	10102	Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	0		BACT-PSD
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PSD-LA-709(M-4)	2821	325211	5/4/2021	PVC Emergency Combustion Equipment A	17.21	Diesel	450	hp	NO_x	10102	Good combustion practices/gaseous fuel burning.	6.9	G/HP-HR	BACT-PSD
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PSD-LA-709(M-4)	2821	325211	5/4/2021	PVC Emergency Combustion Equipment 2A and 2B	17.21	Diesel	300	hp	NO_x	10102	Compliance with 40 CFR 60 Subpart IIII.	0.4	G/KW-HR	BACT-PSD
LA-0382	BIG LAKE FUELS METHANOL PLANT	PSD-LA-781(M1)	2869	325199	4/25/2019	Emergency Engines (EQT0014 - EQT0017)	17.11	Diesel	0		NO_x	10102	Comply with standards of 40 CFR 60 Subpart IIII	0		BACT-PSD
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	PSD-LA-838	4925	486210	9/3/2020	Emergency Engines (EQT0011 - EQT0016)	17.11	Diesel	0		NO_x	10102	Comply with 40 CFR 60 Subpart IIII	0		BACT-PSD
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	NE-12-022	4911	221112	1/30/2014	Emergency Engine/Generator	17.11	ULSD	7.4	MMBTU/H	NO_x	10102		4.8	GM/BHP-H	LAER
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	NE-12-022	4911	221112	1/30/2014	Fire Pump Engine	17.21	ULSD	2.7	MMBTU/H	NO_x	10102		3	GM/BHP-H	LAER
MA-0043	MIT CENTRAL UTILITY PLANT	NE-15-018	8221	611310	6/21/2017	Cold Start Engine	17.11	ULSD	19.04	MMBTU/HR	NO_x	10102		35.09	LB/HR	OTHER CASE-BY-CASE
MD-0042	WILDCAT POINT GENERATION FACILITY	CPCN CASE NO. 9327	4911	221119	4/8/2014	EMERGENCY GENERATOR 1	17.11	ULTRA LOW SULFU DIESEL	2250	KW	NO_x	10102	LIMITED OPERATING HOURS, USE OF ULTRA- LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	4.8	G/HP-H	LAER
MD-0042	WILDCAT POINT GENERATION FACILITY	CPCN CASE NO. 9327	4911	221119	4/8/2014	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	17.21	ULTRA LOW SULFUR DIESEL	477	HP	NO_x	10102	LIMITED OPERATING HOURS, USE OF ULTRA- LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	3	G/HP-H	LAER
MD-0043	PERRYMAN GENERATING STATION	PSC CASE NO. 9136	4911	221119	7/1/2014	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DIESEL	1300	HP	NO_x	10102	GOOD COMBUSTION PRACTICES, LIMITED HOURS OF OPERATION, AND EXCLUSIVE USE OF ULSD	4.8	G/HP-H	LAER
MD-0043	PERRYMAN GENERATING STATION	PSC CASE NO. 9136	4911	221119	7/1/2014	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	17.21	ULTRAL LOW SULFUR DIESEL	350	HP	NO_x	10102	GOOD COMBUSTION PRACTICES, LIMITED HOURS OF OPERATION, AND EXCLUSIVE USE OF ULSD	3	G/HP-H	LAER
MD-0044	COVE POINT LNG TERMINAL	PSC CASE NO. 9318	4911	221119	6/9/2014	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DIESEL	1550	HP	NO_x	10102	GOOD COMBUSTION PRACTICES AND DESIGNED TO ACHIEVE EMISSION LIMIT	4.8	G/HP-H	LAER
MD-0044	COVE POINT LNG TERMINAL	PSC CASE NO. 9318	4911	221119	6/9/2014	5 EMERGENCY FIRE WATER PUMP ENGINES	17.21	ULTRA LOW SULFUR DIESEL	350	HP	NO_x	10102	GOOD COMBUSTION PRACTICES AND DESIGNED TO ACHIEVE EMISSION LIMIT	3	G/HP-H	LAER

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
MI-0394	WARREN TECHNICAL CENTER	160-11	3711	336211	2/29/2012	Four (4) Emergency Generators	17.11	Diesel	2280	KW	NO_x	10102	No add-on controls, but ignition timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	6.93	G/KW-H	BACT-PSD
MI-0394	WARREN TECHNICAL CENTER	160-11	3711	336211	2/29/2012	Nine (9) DRUPS Emergency Generators	17.11	Diesel	3010	KW	NO_x	10102	No add-on controls, but ignition timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	5.98	G/KW-H	BACT-PSD
MI-0395	WARREN TECHNICAL CENTER	160-11A	3711	336211	7/13/2012	Nine (9) DRUPS Emergency Generators	17.11	Diesel	3010	KW	NO_x	10102	No add-on controls, but ignition timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	5.98	G/KW-H	BACT-PSD
MI-0395	WARREN TECHNICAL CENTER	160-11A	3711	336211	7/13/2012	Four (4) Emergency Generators	17.11	Diesel	2500	KW	NO_x	10102	No add-on control, but ignition timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	7.13	G/KW-H	BACT-PSD
MI-0406	RENAISSANCE POWER LLC	51-13	4911	221112	11/1/2013	FG-EMGEN7-8; Two (2) 1,000kW diesel-fueled emergency reciprocating internal combustion engines	17.11	Diesel	1000	kW	NO_x	10102	Good combustion practices	4.8	G/B-HP-H	BACT-PSD
MI-0418	WARREN TECHNICAL CENTER	160-11B	3711	336211	1/14/2015	FG-BACKUPGENS (Nine (9) DRUPS Emergency Engines)	17.11	Diesel	3490	KW	NO_x	10102	No add-on controls, but injection timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	8	G/KW-H	BACT-PSD
MI-0418	WARREN TECHNICAL CENTER	160-11B	3711	336211	1/14/2015	Four (4) emergency engines in FG-BACKUPGENS	17.11	Diesel	2710	KW	NO_x	10102	No add-on controls, but injection timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	7.13	G/KW-H	BACT-PSD
MI-0421	GRAYLING PARTICLEBOARD	59-16	2493	321219	8/26/2016	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	17.11	Diesel	500	H/YR	NO_x	10102	Certified engines, limited operating hours.	22.6	LB/H	BACT-PSD
MI-0421	GRAYLING PARTICLEBOARD	59-16	2493	321219	8/26/2016	Dieself fire pump engine (EUFIREPUMP in FGRICE)	17.11	Diesel	500	H/YR	NO_x	10102	Certified engines, limited operating hours.	3.53	LB/H	BACT-PSD
MI-0423	INDECK NILES, LLC	75-16	4911	221112	1/4/2017	EUEMENGINE (Diesel fuel emergency engine)	17.11	Diesel Fuel	22.68	MMBTU/H	NO_x	10102	Good combustion practices and meeting NSPS IIII requirements.	6.4	G/KW-H	BACT-PSD
MI-0423	INDECK NILES, LLC	75-16	4911	221112	1/4/2017	EUFPENGINE (Emergency engine--diesel fire pump)	17.21	Diesel	1.66	MMBTU/H	NO_x	10102	Good combustion practices and meeting NSPS Subpart IIII requirements.	3	G/BHP-H	BACT-PSD
MI-0425	GRAYLING PARTICLEBOARD	59-16A	2493	321219	5/9/2017	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	17.11	Diesel	500	H/YR	NO_x	10102	Certified engines, limited operating hours.	21.2	LB/H	BACT-PSD
MI-0425	GRAYLING PARTICLEBOARD	59-16A	2493	321219	5/9/2017	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	17.11	Diesel	500	H/YR	NO_x	10102	Certified engines, limited operating hours	4.4	LB/H	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
MI-0425	GRAYLING PARTICLEBOARD	59-16A	2493	321219	5/9/2017	EUFIREPUMP in FGRICE (Diesel fire pump engine)	17.11	Diesel	500	H/YR	NO_x	10102	Certified engines. Limited operating hours.	3.53	LB/H	BACT-PSD
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	167-17 AND 168-17	4911	221112	6/29/2018	EUFPENGINE (South Plant): Fire pump engine	17.21	Diesel	300	HP	NO_x	10102	Good combustion practices and meeting NSPS Subpart IIII requirements.	3	G/BHP-H	BACT-PSD
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	167-17 AND 168-17	4911	221112	6/29/2018	EUEMENGINE (North Plant): Emergency Engine	17.11	Diesel	1341	HP	NO_x	10102	Good combustion practices and meeting NSPS Subpart IIII requirements.	6.4	G/KW-H	BACT-PSD
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	167-17 AND 168-17	4911	221112	6/29/2018	EUFPENGINE (North Plant): Fire pump engine	17.21	Diesel	300	HP	NO_x	10102	Good combustion practices and meeting NSPS Subpart IIII requirements.	3	G/BHP-H	BACT-PSD
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	167-17 AND 168-17	4911	221112	6/29/2018	EUEMENGINE (South Plant): Emergency Engine	17.11	Diesel	1341	HP	NO_x	10102	Good combustion practices and meeting NSPS IIII requirements.	6.4	G/KW-H	BACT-PSD
MI-0434	FLAT ROCK ASSEMBLY PLANT	122-17	8741	561110	3/22/2018	EUENGINE01 through EUENGINE08	17.11	Diesel	3633	BHP	NO_x	10102	Good combustion practices.	6.4	G/KW-H	BACT-PSD
MI-0434	FLAT ROCK ASSEMBLY PLANT	122-17	8741	561110	3/22/2018	EUFIREPUMPENGS (2 emergency fire pump engines)	17.21	Diesel	250	BHP	NO_x	10102	Good combustion practices.	3	G/B-HP-H	BACT-PSD
MI-0434	FLAT ROCK ASSEMBLY PLANT	122-17	8741	561110	3/22/2018	EULIFESAFETYENG - One diesel-fueled emergency engine/generator	17.21	Diesel	500	KW	NO_x	10102	Good combustion practices.	4	G/KW-H	BACT-PSD
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	19-18	4911	221112	7/16/2018	EUEMENGINE: Emergency engine	17.11	Diesel	2	MW	NO_x	10102	State of the art combustion design.	6.4	G/KW-H	BACT-PSD
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	19-18	4911	221112	7/16/2018	EUFPENGINE: Fire pump engine	17.21	Diesel	399	BHP	NO_x	10102	State of the art combustion design.	4	G/KW-H	BACT-PSD
MI-0441	LBWL--ERICKSON STATION	74-18	4911	221112	12/21/2018	EUEMGD1--A 1500 HP diesel fueled emergency engine	17.11	Diesel	1500	HP	NO_x	10102	Good combustion practices and will be NSPS compliant.	6.4	G/KW-H	BACT-PSD
MI-0441	LBWL--ERICKSON STATION	74-18	4911	221112	12/21/2018	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	17.11	Diesel	6000	HP	NO_x	10102	Good combustion practices and will be NSPS compliant.	6.4	G/KW-H	BACT-PSD
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	210-18	4911	221112	8/21/2019	FGEMENGINE	17.11	Diesel	1100	KW	NO_x	10102		5.3	G/HP-H	BACT-PSD
*MI-0445	INDECK NILES, LLC	75-16B	4911	221112	11/26/2019	EUFPENGINE (Emergency engine-diesel fire pump	17.21	diesel fuel	1.66	MMBTU/H	NO_x	10102	Good Combustion Practices and meeting NSPS Subpart IIII requirements	3	G/BHP-H	BACT-PSD
*MI-0445	INDECK NILES, LLC	75-16B	4911	221112	11/26/2019	EUEMENGINE (diesel fuel emergency engine)	17.11	diesel fuel	22.68	MMBTU/H	NO_x	10102	Good Combustion Practices and meeting NSPS Subpart IIII requirements	6.4	G/KW-H	BACT-PSD
MI-0448	GRAYLING PARTICLEBOARD	59-16E	2493	321219	12/18/2020	Emergency diesel generator engine (EUEMRGRICE1 in FGRICE)	17.11	Diesel	500	h/yr	NO_x	10102	Certified engines, limited operating hours	21.2	LB/H	BACT-PSD
MI-0448	GRAYLING PARTICLEBOARD	59-16E	2493	321219	12/18/2020	Emergency diesel generator engine (EUEMRGRICE2 in FGRICE)	17.11	Diesel	500	h/yr	NO_x	10102	Certified Engines, Limited Operating Hours	4.4	LB/H	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
MI-0448	GRAYLING PARTICLEBOARD	59-16E	2493	321219	12/18/2020	Diesel fire pump engine (EUFIREPUMP in FGRICE)	17.11	Diesel	500	h/yr	NO_x	10102	Certified Engines, Limited Operating Hours	3.53	LB/H	BACT-PSD
NJ-0079	WOODBRIDGE ENERGY CENTER	18940 - BOP110003	4911	221112	7/25/2012	Emergency Generator	17.11	Ultra Low Sulfur distillate Diesel	100	H/YR	NO_x	10102	Use of ULSD diesel oil	21.16	LB/H	LAER
NJ-0080	HESS NEWARK ENERGY CENTER	08857/BOP110001	4911	221112	11/1/2012	Emergency Generator	17.11	ULSD	200	H/YR	NO_x	10102	use of ultra low sulfur diesel (ULSD) a clean fuel	18.53	LB/H	LAER
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	18068/BOP150001	4911	221112	3/10/2016	Diesel Fired Emergency Generator	17.11	ULSD	44	H/YR	NO_x	10102	use of ultra low sulfur diesel a clean burning fuel.	42.3	LB/H	LAER
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	18068/BOP150001	4911	221112	3/10/2016	Emergency Diesel Fire Pump	17.21	ULSD	100	H/YR	NO_x	10102	use of ULSD a clean burning fuel, and limited hours of operation	1.7	LB/H	LAER
NY-0103	CRICKET VALLEY ENERGY CENTER	3-1326-00275/00009	4911	221112	2/3/2016	Black start generator	17.11	ultra low sulfur diesel	3000	KW	NO_x	10102	Generator equipped with selective catalytic reduction. Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.	2.11	G/BHP-H	LAER
NY-0103	CRICKET VALLEY ENERGY CENTER	3-1326-00275/00009	4911	221112	2/3/2016	Emergency fire pump	17.21	ultra low sulfur diesel	460	hp	NO_x	10102	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.	2.6	G/BHP-H	LAER
OH-0352	OREGON CLEAN ENERGY CENTER	P0110840	4931	221112	6/18/2013	Emergency fire pump engine	17.21	diesel	300	HP	NO_x	10102	Purchased certified to the standards in NSPS Subpart IIII	1.7	LB/H	BACT-PSD
OH-0352	OREGON CLEAN ENERGY CENTER	P0110840	4931	221112	6/18/2013	Emergency generator	17.11	diesel	2250	KW	NO_x	10102	Purchased certified to the standards in NSPS Subpart IIII	27.8	LB/H	BACT-PSD
OH-0360	CARROLL COUNTY ENERGY	P0113762	4911	221112	11/5/2013	Emergency generator (P003)	17.11	diesel	1112	KW	NO_x	10102	Purchased certified to the standards in NSPS Subpart IIII	13.74	LB/H	BACT-PSD
OH-0360	CARROLL COUNTY ENERGY	P0113762	4911	221112	11/5/2013	Emergency fire pump engine (P004)	17.21	diesel	400	HP	NO_x	10102	Purchased certified to the standards in NSPS Subpart IIII	2.3	LB/H	BACT-PSD
OH-0363	NTE OHIO, LLC	P0116610	4911	221112	11/5/2014	Emergency generator (P002)	17.11	Diesel fuel	1100	KW	NO_x	10102	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII	29.01	LB/H	BACT-PSD
OH-0363	NTE OHIO, LLC	P0116610	4911	221112	11/5/2014	Emergency Fire Pump Engine (P003)	17.21	Diesel fuel	260	HP	NO_x	10102	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII	1.72	LB/H	BACT-PSD
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	P0117655	4911	221112	8/25/2015	Emergency fire pump engine (P004)	17.21	Diesel fuel	140	HP	NO_x	10102	State-of-the-art combustion design	0.81	LB/H	BACT-PSD
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	P0117655	4911	221112	8/25/2015	Emergency generator (P003)	17.11	Diesel fuel	2346	HP	NO_x	10102	State-of-the-art combustion design	21.6	LB/H	BACT-PSD
OH-0367	SOUTH FIELD ENERGY LLC	P0119495	4911	221112	9/23/2016	Emergency fire pump engine (P004)	17.21	Diesel fuel	311	HP	NO_x	10102	State-of-the-art combustion design	1.79	LB/H	BACT-PSD
OH-0367	SOUTH FIELD ENERGY LLC	P0119495	4911	221112	9/23/2016	Emergency generator (P003)	17.11	Diesel fuel	2947	HP	NO_x	10102	State-of-the-art combustion design	27.18	LB/H	BACT-PSD
OH-0368	PALLAS NITROGEN LLC	P0118959	2873	325311	4/19/2017	Emergency Fire Pump Diesel Engine (P008)	17.21	Diesel fuel	460	HP	NO_x	10102	good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII	0.3	LB/H	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
OH-0368	PALLAS NITROGEN LLC	P0118959	2873	325311	4/19/2017	Emergency Generator (P009)	17.11	Diesel fuel	5000	HP	NO_x	10102	good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII	5.5	LB/H	BACT-PSD
OH-0370	TRUMBULL ENERGY CENTER	P0122331	4911	221112	9/7/2017	Emergency generator (P003)	17.11	Diesel fuel	1529	HP	NO_x	10102	State-of-the-art combustion design	16.07	LB/H	BACT-PSD
OH-0370	TRUMBULL ENERGY CENTER	P0122331	4911	221112	9/7/2017	Emergency fire pump engine (P004)	17.21	Diesel fuel	300	HP	NO_x	10102	State-of-the-art combustion design	1.97	LB/H	BACT-PSD
OH-0372	OREGON ENERGY CENTER	P0121049	4911	221112	9/27/2017	Emergency generator (P003)	17.11	Diesel fuel	1529	HP	NO_x	10102	State-of-the-art combustion design	16.1	LB/H	BACT-PSD
OH-0372	OREGON ENERGY CENTER	P0121049	4911	221112	9/27/2017	Emergency fire pump engine (P004)	17.21	Diesel fuel	300	HP	NO_x	10102	State-of-the-art combustion design	1.97	LB/H	BACT-PSD
OH-0374	GUERNSEY POWER STATION LLC	P0122594	4911	221112	10/23/2017	Emergency Generators (2 identical, P004 and P005)	17.11	Diesel fuel	2206	HP	NO_x	10102	Certified to the meet the emissions standards in 40 CFR 89.112 and 89.113 pursuant to 40 CFR 60.4205(b) and 60.4202(a)(2). Good combustion practices per the manufacturerâ's operating manual.	23.21	LB/H	BACT-PSD
OH-0374	GUERNSEY POWER STATION LLC	P0122594	4911	221112	10/23/2017	Emergency Fire Pump (P006)	17.21	Diesel fuel	410	HP	NO_x	10102	Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII. Good combustion practices per the manufacturerâ's operating manual	2.7	LB/H	BACT-PSD
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	P0122829	4911	221112	11/7/2017	Emergency Diesel Generator Engine (P001)	17.11	Diesel fuel	2206	HP	NO_x	10102	Good combustion design	24.71	LB/H	BACT-PSD
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	P0122829	4911	221112	11/7/2017	Emergency Diesel Fire Pump Engine (P002)	17.11	Diesel fuel	700	HP	NO_x	10102	Good combustion design	4.97	LB/H	BACT-PSD
OH-0376	IRONUNITS LLC - TOLEDO HBI	P0123395	3312	331111	2/9/2018	Emergency diesel-fueled fire pump (P006)	17.21	Diesel fuel	250	HP	NO_x	10102	Comply with NSPS 40 CFR 60 Subpart IIII	1.6	LB/H	BACT-PSD
OH-0376	IRONUNITS LLC - TOLEDO HBI	P0123395	3312	331111	2/9/2018	Emergency diesel-fired generator (P007)	17.11	Diesel fuel	2682	HP	NO_x	10102	Comply with NSPS 40 CFR 60 Subpart IIII	28.2	LB/H	BACT-PSD
OH-0377	HARRISON POWER	P0122266	4911	221112	4/19/2018	Emergency Diesel Generator (P003)	17.11	Diesel fuel	1860	HP	NO_x	10102	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	19.68	LB/H	BACT-PSD
OH-0377	HARRISON POWER	P0122266	4911	221112	4/19/2018	Emergency Fire Pump (P004)	17.21	Diesel fuel	320	HP	NO_x	10102	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	2.12	LB/H	BACT-PSD
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	P0124972	2869	325110	12/21/2018	Firewater Pumps (P005 and P006)	17.21	Diesel fuel	402	HP	NO_x	10102	Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII and employ good combustion practices per the manufacturerâ's operating manual	2.64	LB/H	BACT-PSD
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	P0124972	2869	325110	12/21/2018	Emergency Diesel-fired Generator Engine (P007)	17.11	Diesel fuel	3353	HP	NO_x	10102	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturerâ's operating manual	37.41	LB/H	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	P0124972	2869	325110	12/21/2018	1,000 kW Emergency Generators (P008 - P010)	17.11	Diesel fuel	1341	HP	NO_x	10102	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturerâ's operating manual	14.96	LB/H	BACT-PSD
OH-0379	PETMIN USA INCORPORATED	P0125024	3312	331111	2/6/2019	Black Start Generator (P007)	17.21	Diesel fuel	158	HP	NO_x	10102	Tier IV engine Tier IV NSPS standards certified by engine manufacturer.	0.104	LB/H	BACT-PSD
OH-0379	PETMIN USA INCORPORATED	P0125024	3312	331111	2/6/2019	Emergency Generators (P005 and P006)	17.11	Diesel fuel	3131	HP	NO_x	10102	Tier IV engine Tier IV NSPS standards certified by engine manufacturer.	3.45	LB/H	BACT-PSD
OH-0383	PETMIN USA INCORPORATED	P0127678	3312	331111	7/17/2020	Diesel-fired emergency fire pumps (2) (P009 and P010)	17.11	Diesel fuel	3131	HP	NO_x	10102	Tier IV NSPS standards certified by engine manufacturer.	0		BACT-PSD
OK-0145	BROKEN BOW OSB MILL	2003-099-C(M-3)PSD	2493	321219	6/25/2012	Emerg Diesel Gen, Fire Pump, Rail Steam Gen, Air Makeup Units	17.11	Diesel	0		NO_x	10102		0		BACT-PSD
OK-0154	MOORELAND GENERATING STA	2008-302-C(M-1)PSD	4911	221112	7/2/2013	DIESEL-FIRED EMERGENCY GENERATOR ENGINE	17.11	DIESEL	1341	HP	NO_x	10102	COMBUSTION CONTROL	0.011	LB/HP-HR	BACT-PSD
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	08Â·00045A	491	221112	10/10/2012	Emergency Generator	17.11	Diesel	0		NO_x	10102		4.93	G/B-HP-H	OTHER CASE-BY-CASE
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	08Â·00045A	491	221112	10/10/2012	Fire Pump	17.21	Diesel	0		NO_x	10102		2.6	G/B-HP-H	OTHER CASE-BY-CASE
*PA-0282	JOHNSON MATTHEY INC/CATALYTIC SYSTEMS DIV	15-0027K	3714	336399	6/1/2012	ENGINE TEST CELLS (6)	19.9	GASOLINE/DIESEL	27	GAL/H	NO_x	10102		11	T/YR	OTHER CASE-BY-CASE
*PA-0282	JOHNSON MATTHEY INC/CATALYTIC SYSTEMS DIV	15-0027K	3714	336399	6/1/2012	650-KW BACKUP DIESEL GENERATOR	17.11	Diesel / #2 Oil	45.8	GAL/H	NO_x	10102		6.9	G/HP-H	OTHER CASE-BY-CASE
PA-0291	HICKORY RUN ENERGY STATION	37-337A	4911	221112	4/23/2013	EMERGENCY FIREWATER PUMP	17.21	ULTRA LOW SULFUR DISTILLATE	3.25	MMBTU/H	NO_x	10102		1.86	LB/H	OTHER CASE-BY-CASE
PA-0291	HICKORY RUN ENERGY STATION	37-337A	4911	221112	4/23/2013	EMERGENCY GENERATOR	17.11	Ultra Low sulfur Distillate	7.8	MMBTU/H	NO_x	10102		9.89	LB/H	OTHER CASE-BY-CASE
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	35-00069A	4911	221112	12/23/2015	Fire pump engine	17.21	Ultra-low sulfur diesel	15	gal/hr	NO_x	10102		3	GM/HP-HR	LAER
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	35-00069A	4911	221112	12/23/2015	2000 kW Emergency Generator	17.11	Ultra-low sulfur Diesel	0		NO_x	10102		5.45	GM/HP-HR	LAER
PA-0310	CPV FAIRVIEW ENERGY CENTER	11-00536A	4911	221112	9/2/2016	Emergency Generator Engines	17.11	ULSD	0		NO_x	10102		4.8	G/BHP-HR	LAER
PA-0310	CPV FAIRVIEW ENERGY CENTER	11-00536A	4911	221112	9/2/2016	Emergency Fire Pump Engine	17.21	ULSD	0		NO_x	10102		3	G/BHP-HR	LAER
PA-0311	MOXIE FREEDOM GENERATION PLANT	40-00129A	4911	221112	9/1/2015	Fire Pump Engine	17.11	diesel	0		NO_x	10102		3	G/HP-HR	LAER
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	R2-PSD 1	4953	221119	4/10/2014	Emergency Diesel Fire Pump	17.21	ULSD Fuel Oil #2	0		NO_x	10102		2.85	G/B-HP-H	BACT-PSD
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	R2-PSD 1	4953	221119	4/10/2014	Emergency Diesel Generator	17.11	ULSD Fuel oil # 2	0		NO_x	10102		2.85	G/B-HP-H	BACT-PSD
SC-0113	PYRAMAX CERAMICS, LLC	0160-0023	3295	327992	2/8/2012	EMERGENCY ENGINE 1 THRU 8	17.21	DIESEL	29	HP	NO_x	10102	PURCHASE OF CERTIFIED ENGINE.	7.5	GR/KW-H	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
SC-0113	PYRAMAX CERAMICS, LLC	0160-0023	3295	327992	2/8/2012	FIRE PUMP	17.21	DIESEL	500	HP	NO_x	10102	PURCHASE OF CERTIFIED ENGINE BASED ON NSPS, SUBPART IIII.	4	GR/KW-H	BACT-PSD
SC-0113	PYRAMAX CERAMICS, LLC	0160-0023	3295	327992	2/8/2012	EMERGENCY GENERATORS 1 THRU 8	17.11	DIESEL	757	HP	NO_x	10102	ENGINES MUST BE CERTIFIED TO COMPLY WITH NSPS, SUBPART IIII.	4	GR/KW-H	BACT-PSD
TX-0671	PROJECT JUMBO	108446/PSDTX1352	2821	325211	12/1/2014	Engines	17.11	ultra low sulfur diesel fuel	0		NO_x	10102	Each emergency generator's emission factor is based on EPA's Tier 2 standards at 40CFR89.112 for NOx	5.43	G/KW-H	BACT-PSD
TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	118239, N200	2813	325311	4/1/2015	Emergency Diesel Generator	17.11	Diesel	1500	hp	NO_x	10102	Minimized hours of operations Tier II engine	0.0218	G/HP HR	LAER
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	PSDTX1546 AND GHGPSDTX186	2869	325110	2/6/2020	Emergency generator	17.11	DIESEL	0		NO_x	10102	Tier 4 exhaust emission standards specified in 40 CFR Â§ 1039.101, limited to 100 hours per year of non-emergency operation	0		BACT-PSD
TX-0879	MOTIVA PORT ARTHUR TERMINAL	7238 AND PSDTX1548	5171	424710	2/19/2020	Emergency Firewater Engine	17.11	Ultra-low sulfur diesel	0		NO_x	10102	Meeting the requirements of 40 CFR Part 60, Subpart IIII. Firing ultra-low sulfur diesel fuel (no more than 15 ppm sulfur by weight). Limited to 100 hrs/yr of non-emergency operation. Have a non-resettable runtime meter.	0		BACT-PSD
TX-0888	ORANGE POLYETHYLENE PLANT	155952 PSDTX1556 GHGPSDTX192	2821	325211	4/23/2020	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	17.11	Ultra-low Sulfur Diesel	0		NO_x	10102	well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.	0		BACT-PSD
TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX	156571, PSDTX1564, GHGPSDTX195	2869	325199	9/9/2020	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DIESEL	0		NO_x	10102	100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR Â§ 1039.101	0		BACT-PSD
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	160299, PSDTX1576, GHGPSDTX200	2869	325998	9/16/2020	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DIESEL	0		NO_x	10102	limited to 100 hours per year of non-emergency operation	0		BACT-PSD
TX-0933	NACERO PENWELL FACILITY	164137 PSDTX1594 GHGPSDTX207	2869	325110	11/17/2021	Emergency Generators	17.11	Ultra-low sulfur diesel (no more than 15	0		NO_x	10102	limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR Â§ 1039.101) exhaust emission standards	0		BACT-PSD
VA-0325	GREENSVILLE POWER STATION	52525	4911	221112	6/17/2016	DIESEL-FIRED EMERGENCY GENERATOR 3000 kW (1)	17.11	DIESEL FUEL	0		NO_x	10102	Good Combustion Practices/Maintenance	6.4	G/KW	N/A
VA-0325	GREENSVILLE POWER STATION	52525	4911	221112	6/17/2016	DIESEL-FIRED WATER PUMP 376 bph (1)	17.21	DIESEL FUEL	0		NO_x	10102	Good Combustion Practices/Maintenance	0		N/A
VA-0328	C4GT, LLC	52588	4911	221112	4/26/2018	Emergency Diesel GEN	17.11	Ultra Low Sulfur Diesel	500	H/YR	NO_x	10102	good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	4.8	G/HP H	BACT-PSD
VA-0328	C4GT, LLC	52588	4911	221112	4/26/2018	Emergency Fire Water Pump	17.21	Ultra Low Sulfur Diesel	500	HR/YR	NO_x	10102	Good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	3	G/HP-HR	BACT-PSD
VA-0332	CHICKAHOMINY POWER LLC	52610-1	4911	221112	6/24/2019	Emergency Diesel Generator - 300 kW	17.11	Ultra Low Sulfur Diesel	500	H/YR	NO_x	10102	good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	4.8	G/HP-H	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
VA-0332	CHICKAHOMINY POWER LLC	52610-1	4911	221112	6/24/2019	Emegency Fire Water Pump	17.21	Ultra Low Sulfur Diesel	500	HR/YR	NO_x	10102	good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	3	G/HP-HR	BACT-PSD
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	18-JJW-017	4911	221112	4/24/2018	Diesel-Fired Emergency Generators	17.11	Diesel Fuel	0		NO_x	10102	The Use of Ultra-Low Sulfur Fuel and Good Combustion Practices	5.36	G/KWH	BACT-PSD
WI-0286	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	18-JJW-022	3679	334419	4/24/2018	P42 -Diesel Fired Emergency Generator	17.11	Diesel Fuel	0		NO_x	10102	Good Combustion Practices, The Use of an Engine Turbocharger and Aftercooler.	5.36	G/KWH	BACT-PSD
WI-0300	NEMADJI TRAIL ENERGY CENTER	18-MMC-168	4911	221121	9/1/2020	Emergency Diesel Fire Pump (P06)	17.21	Diesel	282	HP	NO_x	10102	Operation limited to 500 hours/year and shall be operated and maintained according to the manufacturerâ's recommendations.	3	G/HP-H	BACT-PSD
WI-0300	NEMADJI TRAIL ENERGY CENTER	18-MMC-168	4911	221121	9/1/2020	Emergency Diesel Generator (P07)	17.11	Diesel	1490	HP	NO_x	10102	Operation limited to 500 hours/year and operate and maintain according to the manufacturerâ's recommendations.	4.8	G/HP-H	BACT-PSD
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	R14-0030	4911	221112	11/21/2014	Emergency Generator	17.11	Diesel	2015.7	HP	NO_x	10102		0		BACT-PSD
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	R14-0030	4911	221112	11/21/2014	Fire Pump Engine	17.21	Diesel	251	HP	NO_x	10102		0		BACT-PSD
WV-0027	INWOOD	R14-0015M	3296	327993	9/15/2017	Emergency Generator - ESDG14	17.11	ULSD	900	bhp	NO_x	10102	Engine Design	4.77	G/HP-HR	BACT-PSD
*WV-0033	MAIDSVILLE	R14-0038	4911	221112	1/5/2022	Emergency Generator	17.11	ULSD	2100	hp	NO_x	10102	Combustion Control (retarded timing and/or lean burn)	24.6	LB/HR	BACT-PSD
*WV-0033	MAIDSVILLE	R14-0038	4911	221112	1/5/2022	Fire Water Pump	17.11	ULSD	240	bhp	NO_x	10102	Combustion control (retarded timing and/or lean burn)	1.59	LB/HR	BACT-PSD
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	CT-12636	491	221112	8/28/2012	Diesel Emergency Generator (EP15)	17.11	Ultra Low Sulfur Diesel	839	hp	NO_x	10102	EPA Tier 2 rated	0		BACT-PSD
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	CT-12636	491	221112	8/28/2012	Diesel Fire Pump Engine (EP16)	17.21	Ultra Low Sulfur Diesel	327	hp	NO_x	10102	EPA Tier 3 rated	0		BACT-PSD

Appendix 4a

Switch Part 70 Technical Support Document (TSD)

DES
DEPARTMENT OF ENVIRONMENT AND SUSTAINABILITY

4701 W. Russell Rd Suite 200
Las Vegas, NV 89118-2231
Phone (702) 455-5942
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PART 70
TECHNICAL SUPPORT DOCUMENT
(STATEMENT of BASIS)

APPLICATION FOR:
Renewal of Part 70 Operating Permit

SUBMITTED BY:
Trinity Consultants, Inc.
7919 Folsom Blvd., Suite 320
Sacramento, CA 95826

FOR:
Switch, Ltd.
Source ID: 16304

LOCATION:
7135 S. Decatur Blvd.
Las Vegas, Nevada 89118

SIC code 7375, "Information Retrieval Services"
NAICS code 517919, "All Other Telecommunications"

July 1, 2021

EXECUTIVE SUMMARY

Switch, Ltd. (Switch) owns and operates six separate and adjacent advanced technology ecosystem communications facilities, referred to as NAP 7, NAP 8, NAP 9, NAP 10, NAP 11, and NAP 12 and is located at 7135 S. Decatur Blvd., Las Vegas, Nevada. The source is under SIC code 7375, "Information Retrieval Services," and NAICS code 517919, "All Other Telecommunications." The source is in Hydrographic Area (HA) 212 (Las Vegas Valley). HA 212 is currently designated as attainment for all pollutants except ozone. HA 212 was designated a marginal nonattainment area for ozone on August 3, 2018 for the 2015 NAAQS. The designation has not imposed any new requirements at this time. HA 212 is also subject to a maintenance plan for the CO and PM_{10} NAAQS.

Switch is permitted as a Part 70 major source of NO_X, a synthetic minor source of CO, and a minor source for all other regulated pollutants. Switch is a source of greenhouse gases (GHG).

The following table summarizes the source potential to emit for each regulated air pollutant from all emission units addressed by this Part 70 Operating Permit:

Source PTE (tons per year)

	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP	GHG[1]
Source PTE	**6.61**	**2.54**	**241.90**	**31.98**	**1.22**	**3.59**	**1.22**	**23,618.83**
Major Source Thresholds (Title V)	100	100	100	100	100	100	10/25[1]	-
Major Stationary Source Thresholds (PSD)	250	250	-	250	250	-	10/25[1]	-
Major Stationary Source Threshold (Nonattainment)	-	-	100	-	-	100	-	-

[1]GHG expressed as CO_2.

Clark County Department of Environment and Sustainability (DES) has delegated authority to implement the requirement of the Part 70 operating permit program (Part 70 OP). Based on information submitted by the applicant and a technical review performed by DAQ staff, DAQ issued an initial Part 70 OP on February 26, 2016, and minor revisions on March 6, 2017, November 27, 2017, June 18, 2018, December 20, 2018, and June 24, 2019. Since that time, Switch applied for renewal of its Part 70 OP on August 11, 2020, and for revisions on May 1, 2020, July 13, 2020, and November 30, 2020. Supplemental information was submitted on February 8, 2021. The Authority to Construct Permit (ATC) that was issued on June 27, 2014 was administratively revised on June 26, 2019, to remove an expiration date of the permit that was included in error, as ATC permits do not expire.

Based on information submitted by the applicant and a technical review performed by DAQ staff, DAQ proposes the issuance of a Part 70 OP to Switch.

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I. ACRONYMS AND ABBREVIATIONS

DAQ	Division of Air Quality
DES	Clark County Department of Environment and Sustainability
AQR	Clark County Air Quality Regulations
AST	aboveground storage tank
ATC	Authority to Construct
CFR	United States Code of Federal Regulations
CO	carbon monoxide
EF	emission factor
EPA	United States Environmental Protection Agency
EU	emission unit
HAP	hazardous air pollutant
HC	hydrocarbon
HP	horse power
IC	internal combustion
kW	kilowatt
MMBtu	millions of British thermal units
NAICS	North American Industry Classification System
NMHC	non-methane hydrocarbon
NO_X	nitrogen oxides
NSPS	New Source Performance Standards
NSR	New Source Review
O&M	operations & maintenance
ORVR	onboard refueling vapor recovery
$PM_{2.5}$	particulate matter less than 2.5 microns
PM_{10}	particulate matter less than 10 microns
ppm	parts per Million
PSD	Prevention of Significant Deterioration
PTE	potential to emit
RACT	reasonably available control technology
SCR	selective catalytic reduction
SIC	Standard Industrial Classification
SO_2	sulfur dioxide
TSD	Technical Support Document
UST	underground storage tank
VAEL	voluntarily accepted emission limitation
VOC	volatile organic compound

II. SOURCE INFORMATION

A. General

Permittee	Switch, Ltd.
Mailing Address	PO Box 400850, Las Vegas, Nevada 89140
Responsible Official	Brandie Koehler, Vice President of Data Center Operations
Source Location	7135 S. Decatur Blvd., Las Vegas, Nevada 89118
Hydrographic Areas	212
SIC Code	7375 – Information Retrieval Services
NAICS Code	517919 – All Other Telecommunications

B. Description of Process

Switch, Ltd. owns and operates six separate and adjacent advanced technology ecosystem communications facilities, referred to as NAP 7, NAP 8, NAP 9, NAP 10, NAP 11, and NAP 12. The source consists of diesel-powered emergency generators, fire pumps, and cooling towers. It is categorized under SIC code 7375, "Information Retrieval Services," and NAICS code 517919, "All Other Telecommunications." The source meets or exceeds the major stationary source threshold for NO_x emissions (NA NSR), is a synthetic minor source of CO, and is a minor source for PM_{10}, $PM_{2.5}$, SO_2, and VOC.

Switch is subject to 40 CFR Part 60, Subpart IIII, and 40 CFR Part 63, Subpart ZZZZ. The engines subject to 40 CFR Part 60, Subpart IIII, satisfy the requirements of 40 CFR Part 63, Subpart ZZZZ, through compliance with 40 CFR Part 60, Subpart IIII.

C. Permitting Action

In the renewal application submitted on August 11, 2020, Switch requested to update the Responsible Official (RO), add the 23 emission units listed in Table II-C-1 to the Operating Permit (OP) from Authority to Construct (ATC) Permits, and increase the TDS for the cooling towers.

In a revision application submitted on May 1, 2020, Switch requested to incorporate 18 emissions units (EUs: F03, F07, F11, J07 through J15, K03, K05 through K07, K09, and K10) which was repeated in the renewal application and to update the date of manufacture for six generators (EUs: J01 through J06) from 2015 to 2018.

In a revision application submitted on July 13, 2020, Switch requested to increase the TDS content of the cooling tower recirculation water from 2,100 ppm to 5,000 ppm. This request was repeated in the renewal application. The increase in TDS concentration for the installed cooling towers is considered a separate project from the original installations and this change was not reasonably foreseeable at the time the ATC applications were submitted. Therefore the increase in emissions resulting from the TDS increase is assessed separately and since the resulting emissions are less than the minor NSR significance thresholds, no controls analysis is required.

In a revision application submitted on November 30, 2020, Switch requested that a cooling tower (EU: D16) be incorporated into the OP with an increased TDS of 5,000 ppm.

In a letter submitted on February 8, 2021, Switch proposed to modify the conditions of the Part 70 OP to allow the use of emergency engines during nonemergency events. DAQ agrees with this change. The use of the engines during nonemergency situations will be included in the 104 hours per calendar year total operation of the units and the 50 hours per calendar year limit of 40 CFR Part 60, Subpart IIII, and 40 CFR Part 63, Subpart ZZZZ.

In reviewing the draft documents, Switch requested the removal of two ATC-Only generators (EUs: A30 and A31) stating that Switch has no plans to construct these units.

During this action, Air Quality has added standard nonroad engine language as Section III-B of the Part 70 OP and has updated the visible emission check language per Air Quality policy.

Table II-C-1: ATC Units Incorporated into the Title V Operating Permit During This Action

EU	EU Description	Make	Model	Serial	DATE DAQ Notified	Delivery Date	Start Up Date
F03	Cooling Tower	Evapco	ESWA 216-460	18-836259	6/18/2019	3/14/2019	5/14/2019
K05	Cooling Tower	Evapco	ESWA 216-460-C	19-871147	8/12/2019	8/8/2019	10/8/2019
K06	Cooling Tower	Evapco	ESWA 216-460-C	19-871155	8/12/2019	8/8/2019	10/8/2019
F07	Cooling Tower	Evapco	ESWA 216-460-C	19-873232	9/5/2019	9/4/2019	11/4/2019
J08	Engine	Detroit Diesel	MTU16V4000 DS2250	95030501820	10/4/2019	10/02/2019	12/02/2019
J10	Engine	Detroit Diesel	MTU16V4000 DS2250	95030501822	10/4/2019	10/02/2019	12/02/2019
J12	Engine	Detroit Diesel	MTU16V4000 DS2250	95030501821	10/4/2019	10/02/2019	12/02/2019
F11	Cooling Tower	EVAPCO	ESWA 216-460	19-872198	10/10/2019	10/10/2019	12/10/2019
K09	Cooling Tower	EVAPCO	ESWA-216-460	19-871162	10/25/2019	10/24/2019	1/30/2020
K10	Cooling Tower	EVAPCO	ESWA-216-460	19-871158	10/25/2019	10/24/2019	1/30/2020
K03	Cooling Tower	EVAPCO	ESWA-216-460-C	19-872170	11/14/2019	11/13/2019	1/13/2020
K07	Cooling Tower	EVAPCO	ESWA-216-460-C	19-872176	11/22/2019	11/22/2019	1/23/2020
J07	Generator	Marathon Electric Detroit Diesel	MTU 16V4000 DS2250 16V4000G83	95030501900 5482000210	2/11/2020	2/6/2020	3/6/2020
J09	Generator	Marathon Electric Detroit Diesel	MTU 16V4000 DS2250 16V4000G83	95030501901 5482000209	2/11/2020	2/6/2020	3/6/2020
J11	Generator	Marathon Electric Detroit Diesel	MTU 16V4000 DS2250 16V4000G83	95030501908 5482000208	2/11/2020	2/6/2020	3/6/2020
J13	Generator	Marathon Electric Detroit Diesel	MTU 16V4000 DS2250 16V4000G83	95030501909 5482000212	4/16/2020	4/10/2020	6/1/2020

EU	EU Description	Make	Model	Serial	DATE DAQ Notified	Delivery Date	Start Up Date
J14	Generator	Marathon Electric Detroit Diesel	MTU 16V4000 DS2250 16V4000G83	95030501910 5482000211	4/16/200	4/10/2020	6/1/2020
J15	Generator	Marathon Electric Detroit Diesel	MTU 16V4000 DS2250 16V4000G83	95030501911 5482000207	4/16/2020	4/13/2020	6/1/2020
J16	Generator	Marathon Electric Detroit Diesel	MTU 16V4000 DS2250 16V4000G24S	95030501979 5482000244	5/14/2020	5/12/2020	6/1/2020
J17	Generator	Marathon Electric Detroit Diesel	MTU 16V4000 DS2250 16V4000G24S	95030501981 5482000246	5/14/2020	5/12/2020	6/1/2020
J18	Generator	Marathon Electric Detroit Diesel	MTU 16V4000 DS2250 16V4000G24S	95030501980 5482000245	5/14/2020	5/12/2020	6/1/2020
F12	Cooling Tower	Evapco	ESWA 216-460	20P101332	6/8/2020	5/27/2020	6/10/2020
K11	Cooling Tower	Evapco	ESWA-216-460	20P103709	11/30/2020	11/18/2020	12/15/2020
D16	Cooling Tower	Evapco	ESWA-216-460	20P104320	11/30/2020	11/19/2020	12/15/2020

III. EMISSION UNITS AND PTE

A. Emission Units

Table III-A-1: Summary of Emissions Units NAP 7

EU	Rating	Description	Make	Model	Serial
A02	2,300 kW	Generator, Emergency	Detroit Diesel	2250 DSEC	2185979
	3,353 hp	Diesel Engine, DOM: 2007			
A03	2,320 kW	Generator, Emergency	Detroit Diesel	744RSL5163	WA-6006372-1219
	3,353 hp	Diesel Engine, DOM: 2007			
A04	2,300 kW	Generator, Emergency	Detroit Diesel	2250 DSEC	2185985
	3,353 hp	Diesel Engine, DOM: 2007			
A05	2,300 kW	Generator, Emergency	Detroit Diesel	2250 DSEC	2183861
	3,353 hp	Diesel Engine, DOM: 2007			
A06	2,300 kW	Generator, Emergency	Detroit Diesel	2250 DSEC	2183870
	3,353 hp	Diesel Engine, DOM: 2007			
A07	2,250 kW	Generator, Emergency	Detroit Diesel	2250RXC6DT2	176196-1-2-0608
	3,353 hp	Diesel Engine, DOM: 2008			
A08	2,250 kW	Generator, Emergency	Detroit Diesel	2250RXC6DT2	175966-1-2-0608
	3,353 hp	Diesel Engine, DOM: 2008			

EU	Rating	Description	Make	Model	Serial
A09	2,250 kW	Generator, Emergency	Detroit Diesel	2250RXC6DT2	175966-1-3-0608
	3,353 hp	Diesel Engine, DOM: 2008			
A10	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	330055-1-2-0311
	3,353 hp	Diesel Engine, DOM: 2010			
A11	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	330055-1-3-0311
	3,353 hp	Diesel Engine, DOM: 2010			
A12	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	330055-1-1-0311
	3,353 hp	Diesel Engine, DOM: 2010			
A13	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	333726-1-1-0811
	3,353 hp	Diesel Engine, DOM: 2011			
A14	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	333726-2-2-0811
	3,353 hp	Diesel Engine, DOM: 2011			
A15	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	333726-2-1-0811
	3,353 hp	Diesel Engine, DOM: 2011			
A16	2,250 kW	Generator, Emergency	Marathon Electric	2250RXC6DT2	334657-1-1-0811
	3,353 hp	Diesel Engine, DOM: 2011			
A17	2,250 kW	Generator, Emergency	Marathon Electric	2250RXC6DT2	341530-1-1-0112
	3,353 hp	Diesel Engine, DOM: 2011			
A18	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	341565-1-3-0212
	3,353 hp	Diesel Engine, DOM: 2011			
A19	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	369767-1-1-0214
	3,353 hp	Diesel Engine, DOM: 2014			
A20	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	341565-1-1-0212
	3,353 hp	Diesel Engine, DOM: 2011			
A21	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	346646-1-1-0512
	3,353 hp	Diesel Engine, DOM: 2011			
A22	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	348117-1-3-0812
	3,353 hp	Diesel Engine, DOM: 2011			
A23	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	348117-1-1-1112
	3,353 hp	Diesel Engine, DOM: 2012			
A24	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	356251-1-4-0213
	3,353 hp	Diesel Engine, DOM: 2013			
A25	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	346646-1-2-0512
	3,353 hp	Diesel Engine, DOM: 2011			
A26	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	348117-1-2-0812
	3,353 hp	Diesel Engine, DOM: 2011			
A27	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	36251-1-1-0213
	3,353 hp	Diesel Engine, DOM: 2013			

EU	Rating	Description	Make	Model	Serial
A28	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	356251-1-2-0213
	3,353 hp	Diesel Engine, DOM: 2013			
A29	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	356251-1-3-0213
	3,353 hp	Diesel Engine, DOM: 2013			
A32	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	369338-1-3-0114
	3,353 hp	Diesel Engine, DOM: 2014			
A33	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	369338-1-1-0114
	3,353 hp	Diesel Engine, DOM: 2014			
A34	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	369338-1-2-0114
	3,353 hp	Diesel Engine, DOM: 2014			
B01	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	7-324424
B02	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	7-324425
B03	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	7-324426
B04	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	7-324359
B05	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	7-324360
B07	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	10-386399
B08	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	10-386400
B09	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	10-386401
B10	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	11-411470
B11	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	11-411468
B12	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	11-411469
B13	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	11-452969
B14	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	11-452982
B15	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	11-452987
B16	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	12-468991
B17	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	12-468982
B18	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	12-468985
B19	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	12-468996
B20	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	13-523739
B21	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	13-658453
B23	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	14-719109

Table III-A-2: Summary of Emissions Units NAP 8

EU	Rating	Description	Make	Model	Serial
C01	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	348116-1-1-0712
	3,353 hp	Diesel Engine, DOM: 2011			
C02	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	348116-1-2-0712
	3,353 hp	Diesel Engine, DOM: 2011			

EU	Rating	Description	Make	Model	Serial
C03	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	348116-1-3-0712
	3,353 hp	Diesel Engine, DOM: 2011			
C04	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	360838-1-3-0713
	3,353 hp	Diesel Engine, DOM: 2013			
C05	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	360838-1-1-0713
	3,353 hp	Diesel Engine, DOM: 2013			
C06	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	360838-1-2-0713
	3,353 hp	Diesel Engine, DOM: 2013			
C07	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	365276-1-1-1013
	3,353 hp	Diesel Engine, DOM: 2013			
C08	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	365276-1-2-1013
	3,353 hp	Diesel Engine, DOM: 2013			
C09	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	365276-1-3-1013
	3,353 hp	Diesel Engine, DOM: 2013			
C10	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	369877-1-1-0514
	3,353 hp	Diesel Engine, DOM: 2014			
C11	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	369877-1-3-0614
	3,353 hp	Diesel Engine, DOM: 2014			
C12	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	369877-1-2-0614
	3,353 hp	Diesel Engine, DOM: 2014			
C13	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	370421-1-1-0514
	3,353 hp	Diesel Engine, DOM: 2014			
C14	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	370421-1-2-0514
	3,353 hp	Diesel Engine, DOM: 2014			
C15	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	370421-1-3-0514
	3,353 hp	Diesel Engine, DOM: 2014			
C16	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	341565-1-2-0212
	3,353 hp	Diesel Engine, DOM: 2011			
C17	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	369767-1-3-0214
	3,353 hp	Diesel Engine, DOM: 2014			
C18	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	369767-1-2-0214
	3,353 hp	Diesel Engine, DOM: 2015			
C19	2,250 kW	Generator, Emergency	Marathon Electric	16V4000DS2250	95030500170
	3,353 hp	Diesel Engine, DOM: 2015			
C20	2,250 kW	Generator, Emergency	Marathon Electric	16V4000DS2250	95030500168
	3,353 hp	Diesel Engine, DOM: 2015			
C21	2,250 kW	Generator, Emergency	Marathon Electric	16V4000DS2250	95030500169
	3,353 hp	Diesel Engine, DOM: 2015			

EU	Rating	Description	Make	Model	Serial
C22	2,250 kW	Generator, Emergency	Marathon Electric	16V4000DS2250	95030500326
	3,353 hp	Diesel Engine, DOM: 2015			
C23	2,250 kW	Generator, Emergency	Marathon Electric	16V4000DS2250	95030500327
	3,353 hp	Diesel Engine, DOM: 2015			
C24	2,250 kW	Generator, Emergency	Marathon Electric	16V4000DS2250	95030500325
	3,353 hp	Diesel Engine, DOM: 2015			
C25	1,500 gpm	Fire Pump	Patterson	8x6 MI	FP-CO114338
	110 hp	Diesel Engine, DOM: 2012	John Deere	4045HFC28	PE4045L219637
C26	200 kW	Generator, Emergency	MTU	MTU 6R0120 DS200	95130500694
	331 hp	Diesel Engine, DOM: 2006+			
D01	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460C	12-485179
D02	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460C	12-485182
D03	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460C	13-544070
D04	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460C	13-544060
D05	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460C	14-673905
D06	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460C	14-686651
D07	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460C	13-655349
D08	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	13-655348
D10	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	14-686661
D11	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460C	14-686648
D12	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460C	14-686653
D13	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	17-820571
D14	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	15-767529
D16	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	20P104320

Table III-A-3: Summary of Emissions Units NAP 9

EU	Rating	Description	Make	Model	Serial
G01	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500461
	3,353 hp	Diesel Engine, DOM: 2016			
G02	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500157
	3,353 hp	Diesel Engine, DOM: 2015			

EU	Rating	Description	Make	Model	Serial
G03	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500463
	3,353 hp	Diesel Engine, DOM: 2016			
G04	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500158
	3,353 hp	Diesel Engine, DOM: 2015			
G05	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500494
	3,353 hp	Diesel Engine, DOM: 2016			
G06	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500159
	3,353 hp	Diesel Engine, DOM: 2015			
G07	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500628
	3,353 hp	Diesel Engine, DOM: 2017			
G08	2,250 kW	Generator, Emergency	Marathon Electric	16V4000DS2250	95030500331
	3,353 hp	Diesel Engine, DOM: 2015			
G09	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500631
	3,353 hp	Diesel Engine, DOM: 2017			
G10	2,250 kW	Generator, Emergency	Marathon Electric	16V4000DS2250	95030500330
	3,353 hp	Diesel Engine, DOM: 2015			
G11	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500634
	3,353 hp	Diesel Engine, DOM: 2017			
G12	2,250 kW	Generator, Emergency	Marathon Electric	16V4000DS2250	95030500332
	3,353 hp	Diesel Engine, DOM: 2015			
G13	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500256
	3,353 hp	Diesel Engine, DOM: 2015			
G14	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500483
	3,353 hp	Diesel Engine, DOM: 2016			
G15	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500255
	3,353 hp	Diesel Engine, DOM: 2015			
G16	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500484
	3,353 hp	Diesel Engine, DOM: 2016			
G17	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500249
	3,353 hp	Diesel Engine, DOM: 2015			
G18	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500485
	3,353 hp	Diesel Engine, DOM: 2016			
G19	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500557
	3,353 hp	Diesel Engine, DOM: 2016			
G20	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500626
	3,353 hp	Diesel Engine, DOM: 2017			

EU	Rating	Description	Make	Model	Serial
G21	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500555
	3,353 hp	Diesel Engine, DOM: 2016			
G22	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500624
	3,353 hp	Diesel Engine, DOM: 2017			
G23	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500625
	3,353 hp	Diesel Engine, DOM: 2017			
G24	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500698
	3,353 hp	Diesel Engine, DOM: 2017			
H01	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	14-715086
H02	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	14715088
H03	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	15770216
H04	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	17-804846
H06	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	16-795374
H07	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	15-758292
H08	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	15-758298
H09	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	15766408
H10	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	15766416
H11	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	16-795365
H12	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	17-818677
H13	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	16782903
H14	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	16782926
H15	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	16801280
H16	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	17804855
H17	800 gpm	Cooling Tower	Evapco	ESWA-102-45J-Z-C	17-822513
H18	800 gpm	Cooling Tower	Evapco	ESWA-102-45J-Z-C	17-822512

Table III-A-4: Summary of Emissions Units NAP 10

EU	Rating	Description	Make	Model	Serial
E01	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500632
	3,353 hp	Diesel Engine, DOM: 2017			
E02	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500493
	3,353 hp	Diesel Engine, DOM: 2016			
E03	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500627
	3,353 hp	Diesel Engine, DOM: 2017			

EU	Rating	Description	Make	Model	Serial
E04	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500462
	3,353 hp	Diesel Engine, DOM: 2016			
E05	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500633
	3,353 hp	Diesel Engine, DOM: 2017			
E06	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500492
	3,353 hp	Diesel Engine, DOM: 2016			
E07	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500703
	3,353 hp	Diesel Engine, DOM: 2017			
E08	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500701
	3,353 hp	Diesel Engine, DOM: 2017			
E09	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500700
	3,353 hp	Diesel Engine, DOM: 2017			
E10	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500702
	3,353 hp	Diesel Engine, DOM: 2017			
E11	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500766
	3,353 hp	Diesel Engine, DOM: 2017			
E12	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500699
	3,353 hp	Diesel Engine, DOM: 2017			
E13	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501092
	3,353 hp	Diesel Engine, DOM: 2018			
E14	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501091
	3,353 hp	Diesel Engine, DOM: 2018			
E15	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501098
	3,353 hp	Diesel Engine, DOM: 2018			
E16	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501065
	3,353 hp	Diesel Engine, DOM: 2018			
E17	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501068
	3,353 hp	Diesel Engine, DOM: 2018			
E18	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501064
	3,353 hp	Diesel Engine, DOM: 2018			
E19	1,500 gpm	Fire Pump	Clarke	8x6 MI	FP-CO133769
	125 hp	Diesel Engine, DOM: 2014	John Deere	4045HFC28	PE4045L266693

EU	Rating	Description	Make	Model	Serial
E20	1,500 gpm	Fire Pump	Clarke	8x6 MI	FP-CO152216
	125 hp	Diesel Engine, DOM: 2016	John Deere	4045HFC28	PE4045N0000 49
F01	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	16-799616
F02	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	16-798860
F03	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	18-836259
F05	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	16-804570
F06	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	16-804573
F07	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	19-873232
F09	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	17-831176
F10	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	17-831179
F11	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	19-872198
F12	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	20P101332

Table III-A-5: Summary of Emissions Units NAP 11

EU	Rating	Description	Make	Model	Serial
J01	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500919
	3,353 hp	Diesel Engine, DOM: 2018			
J02	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500920
	3,353 hp	Diesel Engine, DOM: 2018			
J03	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500921
	3,353 hp	Diesel Engine, DOM: 2018			
J04	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500926
	3,353 hp	Diesel Engine, DOM: 2018			
J05	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500925
	3,353 hp	Diesel Engine, DOM: 2018			
J06	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500927
	3,353 hp	Diesel Engine, DOM: 2018			
J07	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501900
	3,353 hp	Diesel Engine, DOM: 2019	Detroit Diesel	16V4000G83	5482000210
J08	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501820
	3,353 hp	Diesel Engine, DOM: 2019	Detroit Diesel		5482000191
J09	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501901
	3,353 hp	Diesel Engine, DOM: 2019	Detroit Diesel	16V4000G83	5482000209
J10	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501822
	3,353 hp	Diesel Engine, DOM: 2019	Detroit Diesel		5482000192

EU	Rating	Description	Make	Model	Serial
J11	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501908
	3,353 hp	Diesel Engine, DOM: 2019	Detroit Diesel	16V4000G83	5482000208
J12	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501821
	3,353 hp	Diesel Engine, DOM: 2019	Detroit Diesel		5482000190
J13	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501909
	3,353 hp	Diesel Engine, DOM: 2019	Detroit Diesel	16V4000G83	5482000212
J14	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501910
	3,353 hp	Diesel Engine, DOM: 2019	Detroit Diesel	16V4000G83	5482000211
J15	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501911
	3,353 hp	Diesel Engine, DOM: 2019	Detroit Diesel	16V4000G83	5482000207
J16	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501979
	3,353 hp	Diesel Engine, DOM: 2019	Detroit Diesel	16V4000G24S	5482000244
J17	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501981
	3,353 hp	Diesel Engine, DOM: 2019	Detroit Diesel	16V4000G24S	5482000246
J18	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501980
	3,353 hp	Diesel Engine, DOM: 2019	Detroit Diesel	16V4000G24S	5482000245
J19	1,500 gpm	Fire Pump	Patterson	8x6 MI	FP-C0168036-01
	125 hp	Diesel Engine, DOM: 2018	John Deere	6068HFC48	PE6068N007 610
K01	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	17-833057
K02	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	17-833082
K03	1,250 gpm	Cooling Tower	Evapco	ESWA-216-460-C	19-872170
K05	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460-C	19-871147
K06	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460-C	19-871155
K07	1,250 gpm	Cooling Tower	Evapco	ESWA-216-460-C	19-872176
K09	1,250 gpm	Cooling Tower	Evapco	ESWA-216-460	19-871162
K10	1,250 gpm	Cooling Tower	Evapco	ESWA-216-460	19-871158
K11	1,250 gpm	Cooling Tower	Evapco	ESWA-216-460	20P103709

Table III-A-6: Summary of Emissions Units NAP 12

EU	Rating	Description	Make	Model	Serial
L01	2,045 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500548
	3,353 hp	Diesel Engine, DOM: 2016			
L02	2,045 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500549
	3,353 hp	Diesel Engine, DOM: 2016			

Table III-A-7: Summary of ATC-Only Emissions Units

EU	Rating	Description	Make	Model	Serial
NAP 7					
B24	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	TBD
NAP 8					
D09	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	TBD
D15	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	TBD
NAP 9					
H05	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	TBD
NAP 10					
F04	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	TBD
F08	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	TBD
NAP 11					
K04	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	TBD
K08	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	TBD
K12	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	TBD
NAP 12					
L03	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	TBD
	3,353 hp	Diesel Engine, DOM: 2015	MTU Detroit Diesel	16V4000G83	TBD
L04	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	TBD
	3,353 hp	Diesel Engine, DOM: 2015	MTU Detroit Diesel	16V4000G83	TBD

B. Potential to Emit and Status Determination Emissions

Table III-B-1: Individual Emissions Unit PTE (tons per year)

EU Type	Identical EUs Group[1]	Hours per Year	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP
3,353 hp Diesel engine (117 units)	A02-A29, A32-A34, C01-C24, E01-E18, G01-G24, J01-J18, L01, L02	104 each	0.02	0.02	2.06	0.27	0.01	0.03	0.01
1,250 gpm Cooling tower (69 units)	B01-B05, B07-B21, B23, D01-D08, D10-D14, D16, F01-F03, F05-F07, F09-F12, H01-H04, H06-H16, K01-K03, K05-K07, K09-K11	8,760 each	0.06	0.002	0	0	0	0	0
800 gal/min Cooling Tower (2 units)	H17, H18	8,760 each	0.04	0.0002	0	0	0	0	0
125 hp Diesel engine (3 units)	E19, E20, J19	500 each	0.01	0.01	0.19	0.09	0.01	0.01	0.01

EU Type	Identical EUs Group[1]	Hours per Year	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP
110 hp Diesel engine (1 unit)	C25	500	0.01	0.01	0.17	0.07	0.01	0.01	0.01
331 hp Diesel engine (1 unit)	C26	104	0.01	0.01	0.14	0.05	0.01	0.04	0.01

[1] Each EU group consists of identical EUs with identical PTE.

Table III-B-2: ATC-Only Individual Emissions Unit PTE (tons per year)

EU Type	Identical EUs Group[1]	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP
3,353 hp Diesel engine (4 units)	L03, L04	0.02	0.02	2.06	0.27	0.01	0.03	0.01
1,250 gpm Cooling tower (9 units)	B24, D09, D15, F04, F08, H05, K04, K08, K12	0.03	0.0009	0	0	0	0	0

Table III-B-3: Source PTE Summary (tons per any consecutive 12-month period)

Location	EUs	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP
NAP 7	31 emergency generators	0.62	0.62	63.86	8.37	0.31	0.93	0.31
	21 cooling towers	1.26	0.04	0.00	0.00	0.00	0.00	0.00
NAP 8	24 emergency generators	0.48	0.48	49.44	6.48	0.24	0.72	0.24
	14 cooling towers	0.84	0.03	0.00	0.00	0.00	0.00	0.00
	1 emergency generator (331 hp)	0.01	0.01	0.14	0.05	0.01	0.04	0.01
	1 fire pump	0.01	0.01	0.17	0.07	0.01	0.01	0.01
NAP 9	24 emergency generators	0.48	0.48	49.44	6.48	0.24	0.72	0.24
	15 cooling towers	0.90	0.03	0.00	0.00	0.00	0.00	0.00
	2 small cooling towers[1]	0.08	0.01	0.00	0.00	0.00	0.00	0.00
NAP 10	18 emergency generators	0.36	0.36	37.08	4.86	0.18	0.54	0.18
	10 cooling towers	0.60	0.02	0.00	0.00	0.00	0.00	0.00
	2 fire pumps	0.02	0.02	0.38	0.18	0.02	0.02	0.02
NAP 11	18 emergency generators	0.36	0.36	37.08	4.86	0.18	0.54	0.18
	9 cooling towers	0.54	0.02	0.00	0.00	0.00	0.00	0.00
	1 fire pump	0.01	0.01	0.19	0.09	0.01	0.01	0.01
NAP 12	2 emergency generators	0.04	0.04	4.12	0.54	0.02	0.06	0.02
Totals		**6.61**	**2.54**	**241.90**	**31.98**	**1.22**	**3.59**	**1.22**

[1] Small cooling towers are the 800 gpm units.

Refer to the attachments section of this document for the PTE of the ATC-only emission units.

To calculate the SDE, the emergency generators' operational limit of 104 hours per year each is increased to 500 hours per year each in accordance with DES policy. As the cooling towers are unlimited and the fire pumps' PTE is based on 500 hours per year each, there is no difference in PTE and SDE for these units.

Table III-B-4: Source SDE Summary (tons per year)

Location	EUs	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP
NAP 7	31 emergency generators	2.79	2.79	306.59	40.30	0.31	5.27	0.93
	21 cooling towers	1.26	0.04	0.00	0.00	0.00	0.00	0.00
NAP 8	24 emergency generators	2.16	2.16	237.36	31.20	0.24	4.08	0.72
	14 cooling towers	0.84	0.03	0.00	0.00	0.00	0.00	0.00
	1 emergency generator (331 hp)	0.01	0.01	0.14	0.05	0.01	0.04	0.01
	1 fire pump	0.01	0.01	0.17	0.07	0.01	0.01	0.01
NAP 9	24 emergency generators	2.16	2.16	237.36	31.20	0.24	4.08	0.72
	15 cooling towers	0.90	0.03	0.00	0.00	0.00	0.00	0.00
	2 small cooling towers	0.08	0.01	0.00	0.00	0.00	0.00	0.00
NAP 10	18 emergency generators	1.62	1.62	178.02	23.40	0.18	3.06	0.54
	10 cooling towers	0.60	0.02	0.00	0.00	0.00	0.00	0.00
	2 fire pumps	0.02	0.02	0.38	0.18	0.02	0.02	0.02
NAP 11	18 emergency generators	1.62	1.62	178.02	23.4	0.18	3.06	0.54
	9 cooling towers	0.54	0.02	0.00	0.00	0.00	0.00	0.00
	1 fire pump	0.01	0.01	0.19	0.09	0.01	0.01	0.01
NAP 12	2 emergency generators	0.18	0.18	19.78	2.60	0.02	0.34	0.06
Totals		**14.80**	**10.73**	**1,158.01**	**152.49**	**1.22**	**19.97**	**3.56**
Major Source Thresholds		**100**	**100**	**100**	**100**	**100**	**100**	**10/25[1]**

[1] Ten tons for any one HAP or 25 tons for combination of all HAPs.

Switch is a major source of NO_x. With a CO SDE greater than the major source threshold and a CO PTE less than the major source threshold, as a result of the emergency generator operating hour limitation, Switch is considered a synthetic minor of CO emissions. The hour limit is a voluntary limitation.

C. Emissions Increase

Table III-C-1 shows the increase in emissions from the previous Title V OP. The increase is due from incorporation of the emission units listed in Table II-C-1 that were initially permitted in an ATC and the increase in TDS of the cooling tower recirculation water. The ATC units underwent a controls analysis during that those action and are not subject to a controls analysis in this action. The emissions increases due to the TDS increase are below the Minor NSR Significant Levels, therefore, no controls analysis is required in this permitting action.

Table III-C-1: Emissions Increase (tons per year)

EUs	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP
Current PTE	6.61	2.54	241.90	31.98	1.22	3.59	1.22
Previous PTE (06/24/19)	3.90	2.20	217.18	28.74	1.10	3.23	1.10
Emissions Increase	**2.71**	**0.20**	**24.72**	**3.24**	**0.12**	**0.36**	**0.12**
Emissions Increase due to TDS Increase	**2.11**	**0.08**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
AQR 12.5 Minor NSR Significant Levels	**7.5**	**5.0**	**20**	**50**	**20**	**20**	**--**

D. Operational Limitations

Typically, DES allows unlimited operation of emergency generators for emergency use and calculates the PTE based on 500 hours per year usage. The source took a voluntary emission limitation for each emergency generator to avoid becoming a major PSD source of NO_x. Switch uses 2.2 MW emergency generators and is confident they can reasonably limit the cap on hours of operation on the emergency generators and each emergency generator's operation shall be limited to 104 hours per calendar year, including emergencies. This hour limit is also used for the PTE calculation. This accommodates a worst-case emergency use of 55 hours per year and hours for testing and maintenance in accordance with the manufacturer's specifications. Switch has continuously complied with this limit.

The first 59 generators had an operational limit of 155 hours per year. This limit was established to not exceed the NAAQS for NO_2.

Switch has not requested an operational limit for the cooling towers. The fire pumps are limited to 100 hours for testing and maintenance per 40 CFR Part 60, Subpart IIII.

E. Monitoring

The new emission units in this renewal did not trigger additional monitoring requirements, as similar units are present in the permit with sufficient monitoring requirements. The units added to the Title V OP were added to the existing conditions as applicable.

Switch is required to monitor opacity, hours of operation of each generator and fire pump, and the TDS of the cooling towers.

F. Testing

The new emission units did not trigger addition performance testing.

As deemed necessary and upon written request from the Control Officer, Switch may be required to conduct performance testing on any emergency generator or fire pump engine to demonstrate compliance with the emission limits in 40 CFR Part 60, Subpart IIII.

IV. REGULATORY REVIEW

A. Local Regulatory Requirements

DAQ has determined that the following public laws, statutes, and associated regulations are applicable:

1. CAAA (authority: 42 U.S.C. § 7401, et seq.);
2. Title 40 of the CFR, including 40 CFR Part 70 and others;
3. Chapter 445 of the NRS, Sections 401 through 601;
4. Portions of the AQR included in the state implementation plan (SIP) for Clark County, Nevada. SIP requirements are federally enforceable. All requirements from ATC permits issued by DAQ are federally enforceable because these permits were issued pursuant to SIP-included sections of the AQR; and
5. Portions of the AQR not included in the SIP. These locally applicable requirements are locally enforceable only.

B. Federally Applicable Regulations

40 CFR Part 60 (NSPS), Subpart A—General Provisions

40 CFR Part 60.7: Notification and recordkeeping.

Discussion: This regulation requires notification to DES of modifications, opacity testing, and records of malfunctions of process equipment, and performance test data. These requirements are found in the Part 70 OP in Section III. DAQ requires records to be maintained for five years, a more stringent requirement than the two years required by 40 CFR Part 60.7.

40 CFR Part 60.8: Performance tests.

Discussion: Notice of intent to test, the applicable test methods, and acceptable test method operating conditions are outlined in this regulation. DES also reserves the right to require more frequent testing.

40 CFR Part 60.11: Compliance with standards and maintenance requirements.

Discussion: Switch is subject to one NSPS standard: Subpart IIII – Standards for Performance for Stationary Compression Ignition Internal Combustion Engines. Compliance requirements for this standard is discussed in corresponding sections.

40 CFR Part 60.12: Circumvention.

Discussion: This prohibition is addressed in the Part 70 OP. There is also a local rule, AQR 80.1.

40 CFR Part 60, Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

40 CFR Part 60.4200: Applicability determination.

Discussion: The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) with a displacement less than 30 liters per cylinder where the model year is 2007 or later, for engines that are not fire pumps, and July 1, 2006, for ICE certified by National Fire Protection Association as fire pump engines. Switch operates emission units that are subject to this subpart.

40 CFR Part 60.4202: Emission standards for owners and operators.

Discussion: The operator of the stationary CI ICE must provide the manufacturer certification of the emission standards specified in this subpart. These requirements are addressed in the Part 70 OP. By meeting the manufacturer's certified emissions, the emission units are in compliance with the emission standards of this subpart.

40 CFR Parts 60.4206 and 60.4211: Compliance requirements.

Discussion: The operator of the stationary CI ICE must operate and maintain CI ICE that achieve the emission standards according to the manufacturer's written instructions and procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine. These requirements are addressed in the Part 70 OP.

40 CFR Part 60.4214: Reporting and recordkeeping requirements.

Discussion: The operator of the CI ICE shall keep records that include: engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement; emission control equipment; and fuel used. If the stationary CI internal combustion is a certified engine, the owner or operator shall keep documentation from the manufacturer that the engine is certified to meet the emission standards. These requirements are addressed in the Part 70 OP.

40 CFR Part 63, Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

40 CFR Part 63.6585: Applicability determination.

Discussion: The provisions of this subpart are applicable to owners and operators of stationary RICE at major or area sources of HAP. Numeric emission standards are not applied to these emergency engines, however, operational limitations, management practices and record keeping are required. The engines meet the requirements of 40 CFR Part 63, Subpart ZZZZ, by complying with 40 CFR Part 60, Subpart IIII.

40 CFR Part 63, Subpart Q—National Emissions Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers

40 CFR Part 63.400: Applicability.

Discussion: This subpart does not apply to the cooling towers at Switch, as chromium-based water treatment chemical are not used in these units and Switch is not a major source of HAP.

40 CFR Part 64—Compliance Assurance Monitoring

40 CFR Part 64.2: Applicability.

Discussion: CAM does not apply to any emission unit at Switch as no emission unit is subject to an emission limitation or standard, has an uncontrolled PTE greater than a major source threshold, and uses that control device to achieve compliance with the emission standard.

40 CFR Part 72—Acid Rain Permits Regulation

40 CFR Part 72.6: Applicability.

Discussion: There is no emissions unit at this source that meets the definition of affected unit under this rule, therefore, 40 CFR Part 72 does not apply to this source.

40 CFR 75—Continuous Emission Monitoring

Discussion: This source is not subject to the Acid Rain limitations of 40 CFR Part 72, therefore, the source is not subject to the monitoring requirements of this regulation.

C. Permit Shield

Switch did not request a permit shield with this permitting action.

V. CONTROL TECHNOLOGY

Switch is not proposing to construct any new emission units in this permitting action. The emission units incorporated from an ATC will maintain controls required in the ATC.

The emergency generators were required to have RACT for NOx. The generators from this ATC are Tier 2 Certified ICE, use good combustion practices, and have limited hours for testing, maintenance, and operation during emergencies. Each diesel engine is equipped with a turbocharger and with a separate circuit air cooler. The diesel engines will be maintained in accordance with manufacturer's specifications and will use only low sulfur diesel fuel. DAQ agreed that these control equipment and practices met RACT requirements for these diesel engines.

No controls analysis were required for the fire pumps or cooling towers when originally permitted.

Additionally, the source meets the emission standards of 40 CFR Part 60, Subpart IIII, listed in Attachment 3 of this document.

VI. COMPLIANCE

A. Compliance Certification

Recordkeeping requirements are to be kept for all limitations specified in the permit.

1. Requirements for reporting

a. 12.5.2.8: Requirements for compliance certification:

i. Regardless of the date of issuance of this Part 70 OP, the schedule for the submittal of reports to DAQ shall be that in Table VI-A-1.

Table VI-A-1. Reporting Schedule

Required Report	Applicable Period	Due Date
Semiannual report for 1st six-month period	January, February, March, April, May, June	July 30 each year[1]
Semiannual report for 2nd six-month period; any additional annual records required	July, August, September, October, November, December	January 30 each year[1]
Annual Compliance Certification	Calendar year	January 30 each year[1]
Annual Emission Inventory Report	Calendar year	March 31 each year[1]
Notification of Malfunctions, Startup, Shutdowns, or Deviations with Excess Emission	As required	Within 24 hours of the permittee learns of the event
Report of Malfunctions, Startup, Shutdowns, or Deviations with Excess Emission	As required	Within 72 hours of the notification
Deviation Report without Excess Emissions	As required	Along with semiannual reports[1]
Excess Emissions that Pose a Potential Imminent and Substantial Danger	As required	Within 12 hours of the permittee learns of the event
Performance Testing Protocol	As required	No less than 45 days, but no more than 90 days, before the anticipated test date[1]
Performance Testing	As required	Within 60 days of end of test[1]

[1]If the due date falls on a Saturday, Sunday, or federal or Nevada holiday, the submittal is due on the next regularly scheduled business day.

ii. A statement of methods used for determining compliance, including a description of monitoring, recordkeeping, and reporting requirements and test methods.
iii. A schedule for submission of compliance certifications during the permit term.
iv. A statement indicating the source's compliance status with any applicable enhanced monitoring and compliance certification requirements of the Act.

B. Compliance Summary

Table VI-B-1: Applicable Regulations

Citation	Title	Applicability	Applicable Test Method	Compliance Status
AQR Section 0	Definitions	Applicable – Switch will comply with all applicable definitions as they apply.	Switch will meet all applicable test methods should new definitions apply.	Switch complies with applicable requirements.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
AQR Section 4	Control Officer	Applicable – The Control Officer or his representative may enter into Switch property, with or without prior notice, at any reasonable time for purpose of establishing compliance.	Switch will allow Control Officer to enter Station property as required.	Switch complies with applicable requirements.
AQR Section 5	Interference with Control Officer	Applicable – Switch shall not hinder, obstruct, delay, resist, or interfere with the Control Officer.	Switch will allow Control Officer to operate as needed.	Switch complies with applicable requirements.
AQR Section 8	Persons Liable for Penalties	Applicable – Switch and employees will be individually and collectively liable to any penalty or punishment from DES.	Switch will adhere to the rules stipulated in applicable AQR.	Switch complies with applicable requirements.
AQR Section 9	Civil Penalties	Applicable – The rule stipulates penalties for AQR violations.	Switch will adhere to the rules stipulated in applicable AQR.	Switch complies with applicable requirements.
AQR Section 12.0	Applicability, General Requirements and Transition	Applicable – Switch as a whole is not subject to these requirements. Rule outlines source applicability, requirements for a source to obtain a permit and transition for sources that received a permit prior to rulemaking.	Switch applied for and received ATC permits for Air Quality prior to commercial operation. Switch will comply with the requirements of the ATCs.	Switch complies with applicable requirements.
AQR Section 12.4	ATC application and Permit Requirements for Part 70 Sources	Applicable – Switch applied for an ATC from Air Quality.	Switch applied for, and received, ATC permits from Air Quality. Switch shall comply with the requirements for ATCs.	Switch complies with applicable requirements.
AQR Section 12.5	Part 70 Operating Permit Requirements	Applicable – Switch as a whole is applicable. Renewal applications are due 6 to 18 months prior to expiration. Revision applications will be submitted with 12 months of commencing operation of a new emission unit.	Switch complies with the requirements for Title V permits outlined in this AQR and with the current ATC.	Switch complies with applicable requirements.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
AQR Section 12.9	Annual Emissions Inventory	Applicable – Switch shall complete and submit an annual emissions inventory.	Annual emission inventories shall be submitted by March 31 each year.	Switch complies with applicable requirements.
AQR Section 12.10	Continuous Monitoring Requirements	Not Applicable.	Not Applicable.	Not Applicable.
AQR Section 13.2(b)(1) Subpart A	MACT – General Provisions	Applicable – Switch emits hazardous air pollutants.	Switch complies with the applicable requirements of 40 CFR Part 61 and Part 63.	Switch complies with applicable requirements.
AQR Section 13.2(b)(82) Subpart ZZZZ	National Emission Standard for Hazardous Air Pollutants – Stationary Reciprocating Internal Combustion Engines	Applicable – as of May 3, 2013, for the affected units in this permit.	Applicable compliance, monitoring, recordkeeping, and reporting requirements.	Switch complies with applicable requirements.
AQR Section 14.1(b)(1) Subpart A	NSPS – General Provisions	Applicable – Switch is an affected source under the regulations. AQR Section 14 is locally enforceable; however, the NSPS standards they reference are federally enforceable.	Applicable monitoring, recordkeeping and reporting requirements.	Switch complies with applicable requirements.
AQR Section 14.1(b)(80) Subpart IIII	NSPS – Standards of Performance for Stationary Reciprocating Internal Combustion Engines	Applicable – Switch is subject to this regulation.	Switch has met the required certification for these engines.	Switch complies with applicable requirements.
AQR Section 18	Permit and Technical Service Fees	Applicable – Switch will be required to pay all required/applicable permit and technical service fees.	Switch is required to pay all required/applicable permit and technical service fees.	Switch complies with applicable requirements.
AQR Section 21	Acid Rain Permits	Not Applicable.	Not Applicable.	Not Applicable.
AQR Section 22	Acid Rain Continuous Emission Monitoring	Not Applicable.	Not Applicable.	Not Applicable.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
AQR Section 25	Upset/Breakdown, Malfunctions	Applicable – Any upset, breakdown, emergency condition, or malfunction which causes emissions of regulated air pollutants in excess of any permit limits shall be reported to Control Officer. Section 25.1 is locally and federally enforceable.	Any upset, breakdown, emergency condition, or malfunction in which emissions exceed any permit limit shall be reported to the Control Officer within twenty (24) hours of the time that the permittee learns of the event.	Switch complies with applicable requirements.
AQR Section 26	Emissions of Visible Air Contaminants	Applicable – Opacity for the Switch emission units must not exceed 20 percent for more than 6 consecutive minutes.	Compliance determined by EPA Method 9, as required.	Switch complies with applicable requirements.
AQR Section 40	Prohibition of Nuisance Conditions	Applicable – No person shall cause, suffer or allow the discharge from any source whatsoever such quantities of air contaminants or other material which cause a nuisance. Section 40 is locally enforceable only.	Switch air contaminant emissions are controlled by pollution control devices or good combustion in order not to cause a nuisance.	Switch complies with applicable requirements.
AQR Section 41	Fugitive Dust	Applicable – Switch shall take necessary actions to abate fugitive dust from becoming airborne.	Switch utilizes appropriate best practices to not allow airborne fugitive dust.	Switch complies with applicable requirements.
AQR Section 42	Open Burning	Applicable – In the event Switch burns combustible material in any open areas, such burning activity will have been approved by Control Officer in advance. Section 42 is a locally enforceable rule only.	Switch will contact the Air Quality and obtain approval in advance for applicable burning activities as identified in the rule.	Switch complies with applicable requirements.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
AQR Section 43	Odors in the Ambient Air	Applicable – An odor occurrence is a violation if the Control Officer is able to detect the odor twice within a period of an hour, if the odor causes a nuisance, and if the detection of odors is separated by at least fifteen minutes. Section 43 is a locally enforceable rule only.	Switch will not operate its source in a manner which will cause odors.	Switch complies with applicable requirements.
AQR Section 70.4	Emergency Procedures	Applicable – Switch submitted an emergency standby plan for reducing or eliminating air pollutant emissions in the Section 12.5 Operating Permit Application.	Switch submitted an emergency standby plan and received the Section 12.5 Operating Permit.	Switch complies with applicable requirements.
AQR Section 80	Circumvention	Applicable – Switch shall not conceal emissions in any way.	Switch will disclose all emissions as required by state and federal regulations.	Switch complies with applicable requirements.
NRS Chapter 445B	Nevada Revised Statutes, Air pollution	Applicable – Switch shall comply with applicable regulations.	Switch complies with applicable regulations.	Switch complies with applicable requirements.
40 CFR Part 52.1470	State Implementation Plan Rules	Applicable – Switch is subject to the Nevada SIP.	Switch shall continue to comply with the federally enforceable monitoring, testing, recordkeeping, and reporting requirements stipulated in the SIP.	Switch complies with applicable requirements.
40 CFR Part 60 Subpart A	Standards of Performance for New Stationary Sources – General provisions	Applicable – Switch is an affected facility. Therefore, Subpart A provisions are applicable.	Switch shall continue to adhere to applicable monitoring, testing, recordkeeping, and reporting regulations.	Switch complies with applicable requirements.
40 CFR Part 60 Subpart IIII	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines	Applicable – Switch is subject to this regulation.	Switch shall continue to adhere to applicable monitoring, testing, recordkeeping, and reporting regulations.	NAFB complies with applicable requirements.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
40 CFR Part 63 Subpart ZZZZ	National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines	Applicable – The continuous-duty generators/water pump is subject to this subpart.	Switch shall continue to adhere to the applicable emission limitations, operating and maintenance requirements, recordkeeping, reporting, and general provisions.	Switch complies with applicable requirements.
40 CFR Part 70	Federally Mandated Operating Permits	Applicable – The regulations provide for the establishment of State air quality permitting systems consistent with the requirements of Title V of the Clean Air Act.	Switch complies with this regulation by maintaining an updated Title V federal operating permit.	Switch complies with applicable requirements.
40 CFR Part 72	Acid Rain Permit Regulations	Not Applicable.	Not Applicable.	Not Applicable.
40 CFR Part 73	Acid Rain Sulfur Dioxide Allowance System	Not Applicable.	Not Applicable.	Not Applicable.
40 CFR Part 75	Acid Rain Continuous Emission Monitoring	Not Applicable.	Not Applicable.	Not Applicable.

C. Summary of Monitoring for Compliance

Table VI-C-1: Compliance Monitoring

EU	Regulation (40 CFR)	Regulatory Standard	Permit Limit	Is Permit Limit Equal or More Stringent?	Averaging Period Comparison			Streamlining Statement
					Standard	Permit Limit	Is Permit Limit Equal or More Stringent?	
A02-A29, A32-A34, C01-C24, C26, E01-E18, G01-G24, J01-J18, L01, L02	60.4205(b) and 60.4211 (IIII)	Various limits for NOx, CO, PM, and VOC pollutants based on model year and engine power rating		Yes	Compliance demonstrated by keeping records of engine manufacturer's certified emissions data		Yes	The permit requirements and federal standards are identical
C25, E19, E20, J19	60.4205(c) and 60.4211 (IIII)	Various limits for NOx, CO, PM, and VOC pollutants based on model year and engine power rating		Yes	Compliance demonstrated by keeping records of engine manufacturer's certified emissions data		Yes	The permit requirements and federal standards are identical

VII. EMISSION REDUCTION CREDITS (OFFSETS)

The permittee is not required to obtain offsets in this permitting action.

VIII. ADMINISTRATIVE REQUIREMENTS

AQR Section 12.5 requires that Air Quality identify the original authority for each term or condition in the Part 70 OP. Such reference of origin or citation is denoted by [italic text in brackets] after each Part 70 OP condition.

Air Quality proposes to issue the Part 70 OP conditions on the following basis:

Legal:

On December 5, 2001, in 66 FR 30097, EPA fully approved the Title V Operating Permit Program submitted by DES for the purpose of complying with the Title V requirements of the 1990 CAAA and implementing 40 CFR Part 70.

Factual:

Switch has supplied all the necessary information for Air Quality to draft Part 70 OP conditions, encompassing all applicable requirements and corresponding compliance.

Conclusion:

DES has determined that Switch will continue to determine compliance through the use of performance testing, semiannual reporting, and daily and monthly recordkeeping coupled with annual certifications of compliance. Air Quality proceeds with the decision that a Part 70 OP should be issued as drafted to Switch for a period not to exceed five years.

IX. INCREMENT

Switch Ltd is a major source in Hydrographic Area 212 (the Las Vegas Valley). Permitted emission units include 120 generators, 80 cooling towers and four fire pumps. Since minor source baseline dates for NO_x (October 21, 1988) and SO_2 (June 29, 1979) have been triggered, Prevention of Significant Deterioration (PSD) increment analysis is required.

DAQ modeled the source using AERMOD to track the increment consumption. Average annual actual emissions (2018-2019) were used for the generators in the NO_X modeling. Stack data submitted by the applicant were supplemented with information available for similar emission units. Five years (2011 to 2015) of meteorological data from the McCarran Station were used in the model. U.S. Geological Survey National Elevation Dataset terrain data were used to calculate elevations. Table IX-1 shows the location of the maximum impact and the potential PSD increment consumed by the source at that location. The impacts are below the PSD increment limits.

Table IX-1: PSD Increment Consumption

Pollutant	Averaging Period	PSD Increment Consumption by the Source ($\mu g/m^3$)	Location of Maximum Impact	
			UTM X (m)	UTM Y (m)
SO_2	3-hour	10.97[1]	660847	3991932
SO_2	24-hour	6.29[1]	660847	3991932
SO_2	Annual	3.17	660848	3991932
NO_X	Annual	5.79	660848	3991932

[1] Highest Second High Concentration

X. PUBLIC NOTICE

This permitting action is a renewal and therefore is subject to public notice per AQR 12.5.2.17.

XI. PERMIT SHIELD

None has been identified in this permitting action.

XII. ACID RAIN REQUIREMENTS

This source is not subject to the acid rain requirements.

XIII. ATTACHMENTS

Attachment 1 – ATC-only Units

ATC-Only Emission Units PTE Summary (tons per any consecutive 12-month period)

Location	EUs	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP
NAP 7	1 cooling tower (EU: B24)	0.03	0.01	0.00	0.00	0.00	0.00	0.00
NAP 8	2 cooling towers (EUs: D09 and D15)	0.06	0.01	0.00	0.00	0.00	0.00	0.00
NAP 9	1 cooling tower (EU: H05)	0.03	0.01	0.00	0.00	0.00	0.00	0.00
NAP 10	2 cooling towers (EUs: F04 and F08)	0.06	0.01	0.00	0.00	0.00	0.00	0.00
NAP 11	2 cooling towers (EUs: K04, K08, and K12)	0.09	0.01	0.00	0.00	0.00	0.00	0.00
NAP 12	2 emergency generators (EU: L03 and L04)	0.04	0.04	4.12	0.54	0.02	0.06	0.02
	Totals	**0.31**	**0.09**	**4.12**	**0.54**	**0.02**	**0.06**	**0.02**

Attachment 2 – Source PTE Including ATC-Only Emission Units

Emission Units PTE Summary (tons per any consecutive 12-month period)

PTE	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP
Title V OP PTE	6.61	2.54	241.90	31.98	1.22	3.59	1.22
ATC-Only Emission Unit PTE	**0.31**	**0.09**	**4.12**	**0.54**	**0.02**	**0.06**	**0.02**
Totals	**6.92**	**2.63**	**246.02**	**32.52**	**1.24**	**3.65**	**1.24**

Attachment 3 – 40 CFR Part 60, Subpart IIII, Emission Standards

40 CFR Part 60, Subpart IIII, Emission Standards (g/kW-hr)

EU	HC	NO_X	NMHC + NO_X	CO	PM
A02 through A12, C26	1.3	9.2		11.4	0.54
A13 through A29, A32 through A34, C01 through C24, E01 through E18, G01 through G24, J01 through J18, L01, L02			6.4	3.5	0.2
C25, E19, E20, J19			10.5	5.0	0.80

Attachment 4 – Emission Unit EF and PTE Tables

					Emission Factor (lb/hp-hr)	Control Efficiency	Potential Emissions		
EU#	A02-A29, A32-A34, C01-C24, E01-E18, G01-G24, J01-J18, L01, L02		Horsepower:	3,353			lb/hr	lb/day	ton/yr
Make:	Detroit Diesel		Hours/Day:						
Model:	16V4000		Hours/Year	104	**PM10**	1.07E-04	0.00%	0.36	0.00	0.02
S/N:					**NOx**	1.18E-02	0.00%	39.57	0.00	2.06
					CO	1.55E-03	0.00%	5.20	0.00	0.27
Manufacturer Guarantees					**SO_2**	1.21E-05	0.00%	0.04	0.00	0.01
PM10	0.000107	lb/hp-hr			**VOC**	1.97E-04	0.00%	0.66	0.00	0.03
NOx	0.0118	lb/hp-hr			**HAP**	3.05E-05	0.00%	0.10	0.00	0.01
CO	0.00155	lb/hp-hr								
SO_2		lb/hp-hr								
VOC	0.000197	lb/hp-hr								
Engine Type:	Diesel				Diesel Fuel Sulfur Content is 15 ppm (0.0015%)					

					Emission Factor (lb/hp-hr)	Control Efficiency	Potential Emissions		
EU#	A02-A29, A32-A34, C01-C24, E01-E18, G01-G24, J01-J18, L01, L02		Horsepower:	3,353			lb/hr	lb/day	ton/yr
Make:			Hours/Day:						
Model:			Hours/Year	500	**PM10**	1.07E-04	0.00%	0.36	0.00	0.09
S/N:					**NOx**	1.18E-02	0.00%	39.57	0.00	9.89
					CO	1.55E-03	0.00%	5.20	0.00	1.30
Manufacturer Guarantees					**SO_2**	1.21E-05	0.00%	0.04	0.00	0.01
PM10	0.000107	lb/hp-hr			**VOC**	1.97E-04	0.00%	0.66	0.00	0.17
NOx	0.0118	lb/hp-hr			**HAP**	3.05E-05	0.00%	0.10	0.00	0.03
CO	0.00155	lb/hp-hr								
SO_2		lb/hr								
VOC	0.000197	lb/hp-hr								
Engine Type:	Diesel				Diesel Fuel Sulfur Content is 15 ppm (0.0015%)					

					Emission Factor (lb/hp-hr)	Control Efficiency	Potential Emissions lb/hr	Potential Emissions ton/yr
EU#	C25		**Horsepower:**	110				
Make:	Clarke John Deere		**Hours/Day:**					
Model:	JU4H-UFAD5G		**Hours/Year**	500	**PM10**	4.11E-04	0.00%	0.05	0.01
S/N:					**NOx**	6.08E-03	0.00%	0.67	0.17
					CO	2.47E-03	0.00%	0.27	0.07
Manufacturer Guarantees					**SO_2**	1.21E-05	0.00%	0.01	0.01
PM10	0.25	g/kW-hr			**VOC**	1.64E-04	0.00%	0.02	0.01
NOx	3.7	g/kW-hr			**HAP**	4.52E-05	0.00%	0.01	0.01
CO	1.5	g/kW-hr							
SO_2	0.0000121	lb/hp-hr							
VOC	0.1	g/kW-hr							
Engine Type:	Diesel				Diesel Fuel Sulfur Content is 15 ppm (0.0015%)				

					Emission Factor (lb/hp-hr)	Control Efficiency	Potential Emissions lb/hr	Potential Emissions ton/yr
EU#	E19, E20, J19		**Horsepower:**	125				
Make:	Clarke John Deere		**Hours/Day:**					
Model:	JU4H-UFADP0		**Hours/Year**	500	**PM10**	2.79E-04	0.00%	0.03	0.01
S/N:					**NOx**	6.08E-03	0.00%	0.76	0.19
					CO	2.79E-03	0.00%	0.35	0.09
Manufacturer Guarantees					**SO_2**	1.21E-05	0.00%	0.01	0.01
PM10	0.17	g/kW-hr			**VOC**	3.29E-04	0.00%	0.04	0.01
NOx	3.7	g/kW-hr			**HAP**	4.52E-05	0.00%	0.01	0.01
CO	1.7	g/kW-hr							
SO_2	0.0000121	lb/hp-hr							
VOC	0.2	g/kW-hr							
Engine Type:	Diesel				Diesel Fuel Sulfur Content is 15 ppm (0.0015%)				

EU	Description	Model No.	Drift Loss % (1)	Flow Rate (gal/min)	TDS (mg/l)	Hours of Operation hr/day	Hours of Operation hr/yr	PM10 Emissions lb/hr	PM10 Emissions ton/yr	PM2.5 Emissions lb/hr	PM2.5 Emissions ton/yr
B01-B05, B07-B21, B23, D01-D08, D10-D14, D16, F01-F03, F05-F07, F09-F12, H01-H04, H06-H16, K01-K03, K05-K07, K09-K11	Evapco Cooling Tower	ESWA 216-460	0.001%	1250	5000	24	8760	0.01	0.06	0.000464	0.002036

EU	Description	Model No.	Drift Loss % (1)	Flow Rate (gal/min)	TDS (mg/l)	Hours of Operation hr/day	Hours of Operation hr/yr	PM10 Emissions lb/hr	PM10 Emissions ton/yr	PM2.5 Emissions lb/hr	PM2.5 Emissions ton/yr
H17, H18	Evapco Cooling Tower	ESWA-102-45J-Z-C	0.001%	800	5000	24	8760	0.01	0.04	4.2E-05	0.0002

Appendix 5

MGMRI RACT Analysis

REASONABLY AVAILABLE CONTROL TECHNOLOGY REVIEW

MGM RESORTS INTERNATIONAL™

MGM Resorts International / Las Vegas, NV
Source ID # 00825

Prepared By:

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(775) 242-3200

September 2022
Project 222901.0027

Trinity Consultants

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1. EXECUTIVE SUMMARY

MGM Resorts International (MGMRI) has been requested by Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ) to prepare and submit a Reasonably Available Control Technology (RACT) analysis for certain emission units at the contiguous group of hotels owned by MGMRI and located in Las Vegas, Nevada. DAQ issued MGMRI a renewed Part 70 Operating Permit on May 19, 2022 (the Permit) which includes requirements for the following hotels, hereby referred to as "MGMRI Hotels": MGM Grand, New York-New York, Park MGM, The Signature at MGM Grand, Mandalay Bay, The Four Seasons, Luxor, Excalibur, Bellagio, CityCenter, and T-Mobile Arena.

DAQ requested that a RACT analysis be submitted by October 3, 2022, for emission units with a potential-to-emit (PTE) exceeding five tons per year (tpy) of oxides of nitrogen (NO_x) or volatile organic compounds (VOCs) at major sources of NO_x or VOCs, respectively, within Hydrographic Area (HA) 212. This request was triggered as a result of the proposed reclassification of hydrographic area 212 from marginal to moderate nonattainment for ozone.[1] The new classification would require HA 212 to achieve attainment by August 3, 2024, and require DAQ to establish emissions control requirements in its State Implementation Plan (SIP), including RACT requirements.[2] RACT should be considered as the lowest emissions an industrial source is allowed to emit through the use of a control technology that is reasonably available considering technological and economic feasibility.[3]

The MGMRI Hotels are currently a major source of NO_x (i.e., site-wide NO_x PTE is greater than 100 tpy), therefore this analysis considers any emission units at the MGMRI Hotels with PTE greater than five tpy of NO_x. Various natural gas-fired boilers and diesel-fired engines driving emergency generators have potential emissions greater than five tpy of NO_x and therefore are included in this RACT analysis. The site-wide PTE is presented in Table 1-1 of this report and the emission units subject to RACT are summarized in Appendix B.[4]

Table 1-1. Site-Wide PTE (tpy)

Pollutant	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP	GHG
Source Total	87.88	87.88	757.05	367.41	4.98	73.41	21.79	567,540.77

Per the August 1, 2022, DAQ RACT Stakeholder meeting, DAQ is requesting that various information be included in the submittal as applicable.

- General Information, such as:
  - Confirmation of Major Source PTE (Potential to Emit)
  - List of emission units potentially subject to a RACT Requirement

[1] 87 FR 43764.

[2] Per the August 1, 2022, Clark County DAQ 2015 Ozone NAAQ - Reasonably Available Control Technology (RACT) Requirements Presentation.

[3] Ibid.

[4] Site-wide PTE per the Permit.

- Rated size or maximum capacity of each emission unit, and the type of fuel combusted, or the types and quantities of materials processed or produced from the production process in which the emission unit is located

► RACT Specific Information, such as:
- Information sources relied on to identify available control options
- Ranking of available control options based on control effectiveness
- Evaluation of technical feasibility
- Annual cost effectiveness ($/ton)
- Baseline and controlled tpy emission estimates (and basis)
- Environmental, energy, and other impacts (benefits and disbenefits); GHG, HAP or other pollutants
- Proposed RACT emission limitation or averaging approach
- Proposed testing, monitoring, and recordkeeping and reporting meeting periodic or CAM monitoring requirements.

MGMRI has reviewed the technical and economic feasibility of control methods for the natural gas-fired boilers and diesel-fired emergency engines identified in Appendix B. MGMRI determined that complying with the applicable 40 CFR Part 60 Subpart IIII requirements, including emission standards, for stationary compression ignition (CI) internal combustion emergency engines constitutes RACT for TM01 and complying with good combustion practices (GCP) constitutes RACT for all other diesel-fired emergency engines. Additionally, the Facility's diesel-fired emergency engines currently comply with relevant RACT prohibitory rules of other air agencies.

MGMRI determined that the current low NO_x burners with GCP constitute RACT for the affected natural gas-fired boilers. Therefore, there are no proposed changes to the emission limitations and testing, monitoring, and recordkeeping requirements contained in the Permit for the applicable boilers or diesel-fired emergency engines. Section 2 contains a detailed RACT analysis and discussion.

2. REASONABLY ACHIEVABLE CONTROL TECHNOLOGY ASSESSMENT

A RACT evaluation consists of a technical and economic feasibility analysis for implementation of either passive or active methods for reducing emissions. Various options, including control devices and process changes are evaluated to determine their technical feasibility. Those that are deemed technically feasible are evaluated to determine their economic feasibility, which is based on the cost effectiveness of the reduction technique in terms of the cost per ton of pollutant controlled. The cost is the sum of the annualized capital cost and the annual operating cost. Those that exceed a certain threshold are deemed economically infeasible. The technically and economically feasible option that results in the largest decrease in emissions is deemed RACT. MGMRI believes the controls associated with the current level of NO_x emissions from the emergency engines and natural gas-fired boilers are considered RACT and no additional control technology is technically or economically feasible.

2.1 Technically Feasible Options

MGMRI has evaluated RACT for all applicable natural gas-fired boilers and diesel-fired emergency engines at the MGMRI Hotels by determining what process changes and add-on emission controls are technically feasible for this specific type of equipment. Potential emission reduction measures were determined by a review of EPA's RACT/Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC). The following sections provide details on the assessment methodology utilized in the RACT analysis for the affected emission units.

2.1.1 Characterization of Process Equipment

The cost and efficiency of NO_x reduction technology is dependent on the nature of the equipment in which the control device will be installed. Thus, it is important to classify the process equipment properly for the purposes of determining RACT. The process equipment consists of two natural gas-fired boilers with a rating of 32.66 MMBtu/hr and 47 diesel-fired emergency engines with ratings approximately between 1,100 and 3,700 horsepower (hp). Therefore, the boilers are classified as Commercial/Institutional-Sized Boilers/Furnaces (< 100 MMBtu/hr) and the engines as Large Internal Combustion Engines (> 500 hp) for purposes of the RBLC. Please refer to Appendix B for a complete description of each applicable diesel-fired emergency engine and boiler at the Facility.

2.1.2 Identification of Potential Control Technologies

Available NO_x control technologies are identified for each emission unit in question. The following methods are used to identify potential technologies: (1) researching the RBLC database; (2) surveying regulatory agencies; (3) drawing from previous engineering experience; (4) surveying air pollution control equipment vendors; and (5) surveying available literature.

2.1.2.1 RACT/BACT/LAER Clearinghouse (RBLC)

The RBLC, a database made available to the public through the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN), lists technologies and corresponding emission limits that have been approved by regulatory agencies in permit actions. These technologies are grouped into categories by industry and can be referenced in determining what emissions levels were proposed for similar types of emission units.

MGMRI performed searches of the RBLC in September 2022 to identify the emission control technologies and emission levels that were determined by permitting authorities as RACT, BACT, or LAER. Searches were performed for determinations within the past ten (10) years for emission sources comparable to those at MGMRI Hotels. The following categories were searched:

- Commercial/Institutional-Sized Boilers/Furnaces (< 100 MMBtu/hr)
  - Natural Gas (includes propane and liquefied petroleum gas) (RBLC Code 13.310)
- Large Internal Combustion Engines (> 500 hp)
  - Fuel Oil (ASTM #1,2, includes kerosene, aviation, diesel fuel) (RBLC Code 17.110)

The following control technologies are technologically feasible based on the RBLC database search results.

- For natural gas-fired boilers,
  - Use of GCP
  - Low NO_x burners and Flue Gas Recirculation (FGR)
  - Ultra-low NO_x burners (ULNB) and FGR
  - Selective Catalytic Reduction (SCR)
- For diesel-fired emergency engines,
  - Use of GCP
  - EPA Tier Certification

The RBLC search results are available in Appendix A.

2.1.2.2 Technical Feasible Options for Natural Gas Boilers

2.1.2.2.1 Low/Ultra Low NO_x Burners and Flue Gas Recirculation

NO_x is primarily formed through the thermal oxidation of nitrogen and oxygen in the boiler exhaust stream. The FGR system reduces NO_x emissions by recirculating gas that acts as a diluent to reduce combustion temperatures, thus suppressing the thermal NO_x formation. Since recirculating gas acts as a diluent, FGR also reduces NO_x formation by lowering the oxygen concentration in the primary flame zone. An FGR system is normally used in combination with specially designed low NO_x burners. Low NO_x burners reduce NO_x by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame that suppresses thermal NO_x formation. When low NO_x burners and FGR are used in combination, these techniques can reduce NO_x emissions by 60 to 90 percent. In some cases, the addition of NO_x control systems such as low NO_x burners and FGR may also reduce combustion efficiency, resulting in higher CO emissions relative to uncontrolled boilers.[5] ULNB use similar methods to low NO_x burners but can achieve a higher NO_x reduction than low NO_x burners. ULNB can emit as low as 10 parts per million (ppm) of NO_x in some cases.[6]

2.1.2.2.2 Selective Catalytic Reduction

The SCR process chemically reduces the NO_x molecule into molecular nitrogen and water vapor. A nitrogen-based reagent, typically ammonia or urea, is injected into the exhaust stream of a combustion unit. The exhaust gases mix with the nitrogen reagent and pass over a catalyst. The reagent reacts selectively with

[5] AP-42 Chapter 1.4, Natural Gas Combustion https://www.epa.gov/sites/default/files/2020-09/documents/1.4_natural_gas_combustion.pdf

[6] U.S. Department of Energy, Guide to Low-Emission Boiler and Combustion Equipment Selection. ORNL/TM-2002/19. https://www.energy.gov/sites/prod/files/2014/05/f15/guide_low_emission.pdf

the NO_x within a specific temperature range (480°F to 800°F with 700°F to 750°F being optimal) and in the presence of the catalyst and oxygen. SCR is typically cost-effective only on larger industrial boilers (>50 MMBtu/hr for natural gas-fired boilers). SCR can achieve control efficiencies in the range of 70% to 90%.[7] [8]

2.1.2.2.3 Good Combustion Practices

The use of GCP at the facility includes operating boilers to obtain a good air/fuel mixture in the combustion zone by maintaining overall excess oxygen levels high enough to complete combustion while maximizing thermal efficiency and by providing sufficient residence time to complete combustion. GCP also includes operating the equipment in accordance with the manufacturer's recommended settings and preventative maintenance schedules. Following good combustion practices is in the interest of boiler operators from an efficiency and reliability perspective.

2.1.2.3 Technically Feasible Options for Diesel Emergency Engines

2.1.2.3.1 EPA Tier Certification

Certain emergency engines, based on date of manufacture and construction, are certified to comply with EPA Tier Emission Standards as outlined in 40 CFR Part 60 Subpart IIII for stationary CI internal combustion emergency engines or stationary fire pump engines, per the maximum engine power and model year.

2.1.2.3.2 Good Combustion Practices

The use of GCP at the Facility includes operating diesel-fired emergency engines to obtain a good air/fuel mixture in the combustion zone by maintaining overall excess oxygen levels high enough to complete combustion while maximizing thermal efficiency and by providing sufficient residence time to complete combustion. GCP also includes operating the equipment in accordance with the manufacturer's recommended settings and preventative maintenance schedules. Following good combustion practices is in the interest of engine operators from an efficiency and reliability perspective.

2.1.2.4 Technical Feasibility Determination – Natural Gas-Fired Boilers

The four potential controls for the natural gas-fired boilers are listed below:

- GCP (Assumed baseline)
- Low NO_x Burners and FGR
- ULNB and FGR
- SCR

The applicable boilers at the MGMRI Hotels are rated at 32.66 MMBtu/hr (EUs: MG13 and MG14) and are currently equipped with a low NO_x burner to minimize NO_x emissions to <40 ppm at 3% O_2 per Condition III-A-5(c) of the Permit. Therefore, it is assumed that GCP will be implemented for the boilers regardless of other emission controls (or lack thereof). Low NO_x burners and GCP with firing of pipeline-quality natural gas will be used as the baseline emissions scenario for the boiler NO_x RACT analysis.

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[7] EPA Air Pollution Control Technology Fact Sheet EPA-452/F-03-032 https://www3.epa.gov/ttncatc1/dir1/fscr.pdf

[8] EPA Air Pollution Control Cost Manual Section 4, Chapter 2 – Selective Catalytic Reduction (updated on 06/12/2019) Table 2.1b. https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf

The exhaust temperature for smaller boilers (<100 MMBtu/hr) is typically less than the optimal temperature range of 700°F to 750°F. Additionally, publications from EPA[9,10] detail that SCR applications on natural gas burning industrial-commercial boilers are typically only applied to boilers above 100 MMBtu/hr. Therefore, SCR is considered not technically feasible for MG13 and MG14 because the operating temperature and boiler size are not in alignment with optimal SCR operation.

2.1.2.5 Rank Remaining Boiler Control Technologies by Control Effectiveness

The baseline emissions scenario is low NO_x burners and GCP with the firing of pipeline-quality natural gas. This section evaluates additional controls for their reduction effectiveness, as detailed in Table 2-1 below.

Table 2-1. Emission Reduction Calculations

Control Technology	NO_x Emission Factor (lb/MMScf)[1]	NO_x Control Efficiency	Annual Emissions (tpy) [2]	Emissions Reduction (tpy)
Baseline	49.76	-	1.66	-
Low NO_x burner with FGR	32.00	35.69%	1.06	0.59
ULNB with FGR	12.44	75.00%	0.41	1.24

1. Baseline emission factor for low NO_x burners and GCP with firing of pipeline-quality natural gas per the permit limit of 40 ppm NO_x at 3% O_2. Low NO_x burner with FGR emission factor is per AP-42 Chapter 1.4 Table 1.4-1. ULNB with FGR emission factor is per the U.S. Department of Energy, Guide to Low-Emission Boiler and Combustion Equipment Selection (ULNB capable of achieving <10 ppm NO_x in some cases).
2. Annual emissions are calculated by multiplying the 2019 to 2021 average actual fuel rate of 66.6 MMscf/yr, for each EU MG13 and MG14 as they are identical units, by the NOx emission factor for each control technology. The average actual fuel rate is less than 70% of the permitted fuel rate of 280.5 MMscf/yr (32.66 MMBtu/hr / 1020 btu/scf * 8760 hr/yr) and, per DAQ guidance, can be used in this analysis (versus potential fuel rate). Also note that the fuel usage for each of the individual three years (2019, 2020, and 2021) is less than 70% of the permitted fuel rate for each boiler (EUs MG13 and MG14).

2.1.2.6 Technical Feasibility Determination – Diesel-Fired Emergency Engines

The Facility's diesel-fired emergency engines are assumed to use GCP as they are maintained and operated in accordance with manufacturer specifications. Additionally, applicable emission units (EUs) (e.g., TM01) are subject to and comply with 40 CFR Part 60 Subpart IIII requirements, including emission standards per the maximum engine power and model year, for stationary CI internal combustion emergency engines. The use of GCP is technically feasible and has been demonstrated in practice for all applicable emergency engines at the Facility.

Additionally, in its 2010 MACT (Maximum Achievable Control Technology) /GACT (Generally Available Control Technology) evaluation for RICE (Reciprocating Internal Combustion Engines), EPA concluded for emergency RICE: "Because these engines are typically used only a few numbers of hours per year, the costs

[9] EPA Air Pollution Control Cost Manual Section 4, Chapter 2 – Selective Catalytic Reduction (updated on 06/12/2019) Table 2.1b. https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf

[10] EPA Air Pollution Control Technology Fact Sheet: SCR (EPA-452/F-03-032). https://www3.epa.gov/ttncatc1/dir1/fscr.pdf

of emission control are not warranted when compared to the emission reductions that would be achieved."[11] Based on EPA's assessment and the fact that the RBLC contains no records of add on controls (i.e., SCR) installation on emergency-use RICE, add on controls are eliminated from consideration as RACT.

Furthermore, MGM reviewed the current RACT requirements for emergency engines in other agency jurisdictions. For example, San Joaquin Valley Air Pollution Control District (SJVAPCD) Rule 4702 limits emissions of NO_x from internal combustion engines greater than 25 brake horsepower (BHP).[12] Pursuant to SJVAPCD Rule 4702 Section 4.2, emergency engines comply with the Rule by:

- Limiting annual operation and only operating for specific purposes (e.g., testing, maintenance, and emergency purposes),
- Utilizing a non-resettable hour meter,
- Operating and maintaining the engine as recommended by the engine manufacturer, and
- Maintaining records of operation.

Similarly, South Coast Air Quality Management District (SCAQMD) Rule 1110-2 limits NOx emissions from engines. Per Subsection (i) of that Rule, emergency engines are not subject to the emission standards of the Rule (and associated requirements).[13] MGM concludes that the current Permit requirements for the Facility's diesel-fired emergency engines are consistent with the RACT prohibitory requirements of other jurisdictions, such as SJVAPCD and SCAMQD. As such, the installation of add on controls or implementation of additional emission standards is eliminated from consideration as RACT.

2.2 Economic Analysis Summary

The most effective remaining control for natural gas boilers is ULNB with FGR. Economic feasibility is principally based on the tons per year of the pollutant removed and the annualized cost of the control, expressed in dollars per tons of pollutant ($/ton).

MGMRI reviewed publicly available data for the material cost of the addition of FGR to a low NO_x burner and for ULNB burners with FGR; the economic analysis for these control options is shown in Table 2-2 below.

Table 2-2. NO_x RACT Economic Feasibility Analysis

Control Technology	Total Emissions Reduction (tpy)	Total Capital Investment of Control ($USD) [1, 2]	Total Annual Equipment Cost ($USD) [3]	Total Annual Operating Cost ($USD) [4]	Total Cost per Ton ($USD/Ton) [5]
Baseline	-	-	-	-	-
Low NO_x burner with FGR	0.59	77,200.00	13,587.20	39,520.61	89,869.40

[11] U.S. EPA, Memorandum: Response to Public Comments on Proposed National Emission Standards for Hazardous Air Pollutants for Existing Stationary Reciprocating Internal Combustion Engines Located at Area Sources of Hazardous Air Pollutant Emissions or Have a Site Rating Less Than or Equal to 500 Brake HP Located at Major Sources of Hazardous Air Pollutant Emissions, August 10, 2010, p. 172-173. (EPA-HQ-OAR-2008-0708).

[12] SJVAPCD Rule 4702, Amended August 19, 2021. https://www.valleyair.org/rules/currntrules/r4702.pdf

[13] SCAQMD Rule 1110-2, Amended November 1, 2019. http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1110-2.pdf?sfvrsn=4

Control Technology	Total Emissions Reduction (tpy)	Total Capital Investment of Control ($USD) [1, 2]	Total Annual Equipment Cost ($USD) [3]	Total Annual Operating Cost ($USD) [4]	Total Cost per Ton ($USD/Ton) [5]
ULNB with FGR	1.24	126,200.00	22,211.20	39,520.61	49,707.34

1. The total installed capital equipment costs are from the Bay Area Air Quality Management District (BAAQMD) Example Cost-Effectiveness Calculations for NOx Controls for FGR and ULNB. It was assumed that the low NO_x burner costs are equivalent to the costs of a ULNB. Since the BAAQMD example includes the installation of an SCR only a third of the labor and engineering costs, included in the BAAQMD cost estimates, were included in these costs estimates. [14]
2. It is assumed that the new FGR fan will be 40 hp and the existing FD fan will increase from 25 to 40 HP. The increased size of the FD fan is associated with the increased mass flow from flue gas recirculation.
3. Annualized equipment costs are determined using the simplified formula Cost Effectiveness Determination for BACT below: Annualized Equipment Cost = $ Capital Investment [CRF (0.136) + Tax (0.01) + Ins. (0.01) + G&A (0.02)] Capital Recovery Factor (CRF) of 0.136 is per Table A.2 of the EPA Chapter 2 Cost Estimation: Concepts and Methodology, for 6% interest over 10 years[15]
4. The units can operate 8,760 hours per year, and this was used to determine the annual operating costs.
5. The total cost per ton is determined as the total emissions reduction divided by the sum of the total annual equipment cost and the annual operating costs.

2.2.1 Selection of NO_x RACT for the Diesel-Fired Emergency Engines

As discussed in Section 2.1.2.6, the Facility's diesel-fired emergency engines use GCP as they are maintained and operated in accordance with manufacturer specifications. EU TM01 is certified to comply with the applicable emission standards as outlined in 40 CFR Part 60 Subpart IIII for stationary CI internal combustion emergency engine, per the maximum engine power and model year. As discussed previously, the installation of add-on controls to the existing emergency engines is not feasible per EPA and other agencies' RACT prohibitory rules (e.g., SCAQMD and SJVAPCD) do not require compliance with specific NO_x emission standards for emergency engines. Therefore, the use of GCP is technically feasible and is selected as meeting RACT for the diesel-fired emergency engines. Additionally, compliance with applicable 40 CFR Part 60 Subpart IIII requirements, such as emission standards, will be selected as RACT for EUs subject to this regulation (e.g., EU TM01).

MGMRI intends to maintain the current emission limits for NO_x as contained in the Permit for each of the affected diesel emergency engines. MGMRI will utilize the existing Permit conditions to monitor compliance with the NO_x emission limits contained in the Permit.

2.2.2 Selection of NO_x RACT for the Natural Gas-Fired Boilers

The result of the economic analysis (Section 2.2) shows that low NO_x burners with FGR has significantly higher costs on a $/ton then ULNB with FGR, while both are not economically feasible. The cost per ton calculated for either control option significantly exceeds cost effectiveness thresholds defined by other agencies, such as SJVAPCD.[16] ULNB being a significantly more costly capital investment (mainly due to the costs of installing the ULNB and FGR system) and has additional considerations for increased CO emissions.

[14] BAAQMD Example Cost-Effectiveness Calculations for NO_x Controls for FGR and ULNB https://www.baaqmd.gov/~/media/files/engineering/bact-tbact-workshop/appendix/cost-effectiveness-calculations-nox.pdf

[15] EPA Chapter 2 Cost Estimation: Concepts and Methodology, November 2017 https://www.epa.gov/sites/default/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

[16] For example, SJVAPCD NO_x cost effectiveness threshold of $32,900 $/ton per SJVAPCD Policy 1305, https://www.valleyair.org/policies_per/Policies/APR%201305.pdf.

As such, MGMRI concludes that the current low NO_x burners and GCP with firing of pipeline-quality natural gas is considered RACT for MG13 and MG14.

MGMRI intends to maintain the current emission limits for NO_x as contained in the Permit for each of the MG13 and MG14. MGMRI will utilize the existing Permit conditions to monitor compliance with the NO_x emission limits contained in the Permit.

APPENDIX A: SUMMARY OF RBLC

Table 1. NOx RBLC Data For Diesel Generators

RBLCID	Facility Name	Permit No.	Facility State	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
AK-0076	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT01	AK	1382	211111	8/20/2012	COMBUSTION OF DIESEL BY ICES	17.11	ULSD	1,750	KW	NO_x	10102		6.4	G/KW-H	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	AK	1382	211111	1/23/2015	REMOTE INCINERATOR GENERATOR ENGINE	21.4	ULTRA-LOW SULFUR DIESEL	102	HP	NO_x	10102		3	LB/TON	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	AK	1382	211111	1/23/2015	EMERGENCY CAMP GENERATORS	17.11	ULTRA-LOW SULFUR DIESEL	2,695	HP	NO_x	10102		4.8	GRAMS/HP-H	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	AK	1382	211111	1/23/2015	AIRSTRIP GENERATOR ENGINE	17.21	ULTRA-LOW SULFUR DIESEL	490	HP	NO_x	10102		4.8	GRAMS/HP-H	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	AK	1382	211111	1/23/2015	AGITATOR GENERATOR ENGINE	17.21	ULTRA-LOW SULFUR DIESEL	98	HP	NO_x	10102		5.6	GRAMS/HP-H	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	AK	1382	211111	1/23/2015	INCINERATOR GENERATOR ENGINE	17.21	ULTRA-LOW SULFUR DIESEL	102	HP	NO_x	10102-44-0		4.9	GRAMS/HP-H	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	AK	1382	211111	1/23/2015	FINE WATER PUMPS	17.11	ULTRA-LOW SULFUR DIESEL	610	HP	NO_x	10102		3	GRAMS/HP-H	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	AK	1382	211111	1/23/2015	BULK TANK GENERATOR ENGINES	17.11	ULTRA-LOW SULFUR DIESEL	891	HP	NO_x	10102		4.8	GRAMS/HP-H	BACT-PSD
AK-0084	DONLIN GOLD PROJECT	AQ0934CPT01	AK	1041	212221	6/30/2017	BLACK START AND EMERGENCY INTERNAL COMBUSTION ENGINES	17.11	DIESEL	1,500	KW	NO_x	10102	GOOD COMBUSTION PRACTICES	8	G/KW-HR	BACT-PSD
AK-0084	DONLIN GOLD PROJECT	AQ0934CPT01	AK	1041	212221	6/30/2017	FIRE PUMP DIESEL INTERNAL COMBUSTION ENGINES	17.21	DIESEL	252	HP	NO_x	10102	GOOD COMBUSTION PRACTICES	3.7	G/KW-HR	BACT-PSD
AK-0085	GAS TREATMENT PLANT	AQ1524CPT01	AK	4922	486210	8/13/2020	ONE (1) BLACK START GENERATOR ENGINE	17.11	ULSD	186.60	GPH	NO_x	10102	GOOD COMBUSTION PRACTICES, LIMIT OPERATION TO 500 HOURS PER YEAR.	3.3	G/HP-HR	BACT-PSD
AK-0085	GAS TREATMENT PLANT	AQ1524CPT01	AK	4922	486210	8/13/2020	THREE (3) FIREWATER PUMP ENGINES AND TWO (2) EMERGENCY DIESEL GENERATORS	17.21	ULSD	19.4	GPH	NO_x	10102	GOOD COMBUSTION PRACTICES, LIMIT OPERATION TO 500 HOURS PER YEAR PER ENGINE	3.6	G/HP-HR	BACT-PSD
AK-0088	LIQUEFACTION PLANT	AQ1539CPT01	AK	4922	488999	7/7/2022	DIESEL FIRE PUMP ENGINE	17.11	DIESEL	27.9	GAL/HR	NO_x	10102	GOOD COMBUSTION PRACTICES; LIMITED OPERATION; 40 CFR 60 SUBPART IIII	3.6	G/HP-HR	BACT-PSD
AK-0088	LIQUEFACTION PLANT	AQ1539CPT01	AK	4922	488999	7/7/2022	AUXILIARY AIR COMPRESSOR ENGINE	17.21	DIESEL	14.6	GAL/HR	NO_x	10102	GOOD COMBUSTION PRACTICES; LIMITED OPERATION; 40 CFR 60 SUBPART IIII	0.45	G/HP-HR	BACT-PSD
AL-0301	NUCOR STEEL TUSCALOOSA, INC.	413-0033-X014 - X020	AL	3312	331111	7/22/2014	DIESEL FIRED EMERGENCY GENERATOR	17.11	DIESEL	800	HP	NO_x	10102		0.015	LB/HP-H	BACT-PSD
*AL-0318	TALLADEGA SAWMILL	309-0075	AL	2421	321113	12/18/2017	250 HP EMERGENCY CI, DIESEL-FIRED RICE	17.11	DIESEL	0		NO_x	10102		0		N/A
AL-0328	PLANT BARRY	503-1001	AL	4911	221112	11/9/2020	DIESEL EMERGENCY ENGINES	17.11	DIESEL	0		NO_x	10102		3	GR/BHP-HR	BACT-PSD
AR-0161	SUN BIO MATERIAL COMPANY	2384-AOP-R0	AR	2611	322110	9/23/2019	EMERGENCY ENGINES	17.11	DIESEL	0		NO_x	10102	GOOD OPERATING PRACTICES, LIMITED HOURS OF OPERATION, COMPLIANCE WITH NSPS SUBPART IIII	0.4	G/KW-H	BACT-PSD
AR-0163	BIG RIVER STEEL LLC	2305-AOP-R6	AR	3312	331111	6/9/2019	EMERGENCY ENGINES	17.11	DIESEL	0		NO_x	10102	GOOD OPERATING PRACTICES, LIMITED HOURS OF OPERATION, COMPLIANCE WITH NSPS SUBPART IIII	4.86	G/KW-HR	BACT-PSD
CA-1219	CITY OF SAN DIEGO PUD (PUMP STATION 1)	2012--APP-002009	CA	4952	221320	7/9/2012	IC ENGINE	17.11	DIESEL	2,722	BHP	NO_x	10102	TIER 2 CERTIFIED ENGINE AND 50 HR/YR FOR M&T	4	G/B-HP-H	OTHER CASE-BY-CASE

* Represents draft entries into the RBLC which may not be complete.

Table 1. NOx RBLC Data For Diesel Generators

RBLCID	Facility Name	Permit No.	Facility State	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
DC-0009	BLUE PLAINS ADVANCED WASTEWATER TREATEMENT PLANT	6372-A1	DC	4952	221320	3/15/2012	DIESEL EMERGENCY GENERATOR	17.11	ULTRA-LOW SULFUR DIESEL	2,682	HP	NO_x	10102		31.87	LB/HR	LAER
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	MAIN PROPULSION ENGINES DEVELOPMENT DRILLER 1	17.11	DIESEL	0		NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES, AND ADDITIONAL ENHANCED WORK PRACTICE STANDARDS INCLUDING AN ENGINE PERFORMANCE MANAGEMENT SYSTEM, POSITIVE CRANKCASE VENTILATION, TURBOCHARGER WITH AFTERCOOLER, AND HIGH PRESSURE FUEL INJECTION WITH AFTERCOOLER.	12.1	G/KW-H	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	MAIN PROPULSION ENGINES C.R. LUIGS	17.11	DIESEL	5,875	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES, AND ADDITIONAL ENHANCED WORK PRACTICE STANDARDS INCLUDING AN ENGINE PERFORMANCE MANAGEMENT SYSTEM, POSITIVE CRANKCASE VENTILATION, TURBOCHARGER WITH AFTERCOOLER, AND HIGH PRESSURE FUEL INJECTION WITH AFTERCOOLER.	18.1	G/KW-H	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	WIRELINE UNIT ENGINES - C.R. LUIGS	17.21	DIESEL	300	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES, USE OF LOW SULFUR DIESEL FUEL, TURBOCHARGER WITH AFTERCOOLER, HIGH PRESSURE FUEL INJECTION WITH AFTERCOOLER	8.92	T/12MO ROLLING TOTAL	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	FAST RESCUE CRAFT DIESEL ENGINE - DEVELOPMENT DRILLER 1	17.21	DIESEL	142	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES, USE OF LOW SULFUR DIESEL FUEL, AND TURBOCHARGER	0		BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	LIFE BOAT DIESEL ENGINES - DEVELOPMENT DRILLER 1	17.21	DIESEL	110	HP	NO_x	10102-44-0	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES AND USE OF LOW SULFUR DIESEL FUEL	0		BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	PORT AND STB FWD AND AFT CRANE DIESEL ENGINES - C.R. LUIGS	17.21	DIESEL	305	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES, USE OF LOW SULFUR DIESEL FUEL, POSITIVE CRANKCASE VENTILATION, TURBOCHARGER WITH AFTERCOOLER, HIGH PRESSURE FUEL INJECTION WITH AFTERCOOLER	82.83	T/12MO ROLLING TOTAL	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	FAST RESCUE CRAFT DIESEL ENGINE - C.R. LUIGS	17.11	DIESEL	142	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES AND USE OF LOW SULFUR DIESEL FUEL	0		BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	SEISMIC OPERATIONS DIESEL ENGINES - DEVELOPMENT DRILLER 1	17.21	DIESEL	415	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES, USE OF LOW SULFUR DIESEL FUEL, AND TURBOCHARGER	3.54	TONS	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	LIFE BOAT DIESEL ENGINES - C.R. LUIGS	17.21	DIESEL	39	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES, USE OF LOW SULFUR DIESEL FUEL	0		BACT-PSD

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Table 1. NOx RBLC Data For Diesel Generators

RBLCID	Facility Name	Permit No.	Facility State	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	EMERGENCY GENERATOR DIESEL ENGINE - DEVELOPMENT DRILLER 1	17.11	DIESEL	2,229	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES, USE OF LOW SULFUR DIESEL FUEL, POSITIVE CRANKCASE VENTILATION, TURBOCHARGER WITH AFTERCOOLER, HIGH PRESSURE FUEL INJECTION WITH AFTERCOOLER	1.6	T/12MO ROLLING TOTAL	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	CEMENTING AND NITROGEN PUMP DIESEL ENGINES - DEVELOPMENT DRILLER 1	17.21	DIESEL	0		NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES, USE OF LOW SULFUR DIESEL FUEL, POSITIVE CRANKCASE VENTILATION, TURBOCHARGER, AND HIGH PRESSURE FUEL INJECTION WITH AFTERCOOLER	9.5	T/12MO ROLLING TOTAL	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	WIRELINE UNIT DIESEL ENGINES - DEVELOPMENT DRILLER 1	17.21	DIESEL	0		NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES, USE OF LOW SULFUR DIESEL FUEL, TURBOCHARGER WITH AFTERCOOLER, HIGH PRESSURE FUEL INJECTION WITH AFTERCOOLER	8.92	TONS	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	BLACK START AIR COMPRESSOR - C.R. LUIGS	17.21	DIESEL	6	HP	NO_x	10102-44-0	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THE ENGINE AND THE USE OF LOW SULFUR DIESEL FUEL	0		BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	EMERGENCY GENERATOR DIESEL ENGINE - C.R. LUIGS	17.11	DIESEL	2,064	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES, USE OF LOW SULFUR DIESEL FUEL, POSITIVE CRANKCASE VENTILATION, TURBOCHARGER WITH AFTERCOOLER, HIGH PRESSURE FUEL INJECTION WITH AFTERCOOLER	1.49	T/12MO ROLLING TOTAL	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	CEMENTING AND NITROGEN PUMP DIESEL ENGINES - C.R. LUIGS	17.21	DIESEL	0		NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES, USE OF LOW SULFUR DIESEL FUEL, POSITIVE CRANKCASE VENTILATION, TURBOCHARGER, AND HIGH PRESSURE FUEL INJECTION WITH AFTERCOOLER	8.69	T/12MO ROLLING TOTAL	BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	FL	1381	211111	9/16/2014	MAIN PROPULSION GENERATOR DIESEL ENGINES	17.11	DIESEL	9,910	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE MOST RECENT MANUFACTURER'S SPECIFICATIONS ISSUED FOR ENGINES AND WITH TURBOCHARGER, AFTERCOOLER, AND HIGH INJECTION PRESSURE	12.7	G/KW-H	BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	FL	1381	211111	9/16/2014	DIESEL POWERED FORKLIFT ENGINE	17.21	DIESEL	30	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE MOST RECENT MANUFACTURER'S SPECIFICATIONS ISSUED FOR ENGINE	0		BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	FL	1381	211111	9/16/2014	WIRELINE DIESEL ENGINES	17.21	DIESEL	0		NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE MOST RECENT MANUFACTURER'S SPECIFICATIONS ISSUED FOR ENGINE AND WITH TURBOCHARGER, AFTERCOOLER, AND HIGH INJECTION PRESSURE	0		BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	FL	1381	211111	9/16/2014	WATER BLASTING DIESEL ENGINE	17.21	DIESEL	208	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE MOST RECENT MANUFACTURER'S SPECIFICATIONS ISSUED FOR ENGINE AND WITH TURBOCHARGER, AFTERCOOLER, AND HIGH INJECTION PRESSURE	0		BACT-PSD

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RBLCID	Facility Name	Permit No.	Facility State	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	FL	1381	211111	9/16/2014	WELL EVALUATION DIESEL ENGINE	17.21	DIESEL	140	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE MOST RECENT MANUFACTURER'S SPECIFICATIONS ISSUED FOR ENGINE	0		BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	FL	1381	211111	9/16/2014	FAST RESCUE CRAFT DIESEL ENGINE	17.21	DIESEL	230	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE MOST RECENT MANUFACTURER'S SPECIFICATIONS ISSUED FOR ENGINE AND WITH TURBOCHARGER, AFTERCOOLER, AND HIGH INJECTION PRESSURE	0		BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	FL	1381	211111	9/16/2014	ESCAPE CAPSULE DIESEL ENGINE	17.21	DIESEL	39	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE MOST RECENT MANUFACTURER'S SPECIFICATIONS ISSUED FOR ENGINE	0		BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	FL	1381	211111	9/16/2014	EMERGENCY DIESEL ENGINE	17.11	DIESEL	3,300	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE MOST RECENT MANUFACTURER'S SPECIFICATIONS ISSUED FOR ENGINES AND WITH TURBOCHARGER, AFTERCOOLER, AND HIGH INJECTION PRESSURE	0		BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	FL	1381	211111	9/16/2014	REMOTELY OPERATED VEHICLE EMERGENCY GENERATOR	17.21	DIESEL	427	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE MOST RECENT MANUFACTURER'S SPECIFICATIONS ISSUED FOR ENGINES AND WITH TURBOCHARGER, AFTERCOOLER, AND HIGH INJECTION PRESSURE	0		BACT-PSD
FL-0348	MURPHY EXPLORATION & PRODUCTION CO.	OCS-EPA-R4009	FL	1381	213111	5/15/2012	MAIN PROPULSION GENERATORS	17.21	DIESEL	4,425	HP	NO_x	10102	USE OF ENGINE WITH TURBO CHARGER WITH AFTER COOLER, AN ENHANCED WORK PRACTICE POWER MANAGEMENT, NOX EMISSIONS MAINTENANCE SYSTEM, AND GOOD COMBUSTION AND MAINTENANCE PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR EACH ENGINE	26	G/KW-H	BACT-PSD
FL-0348	MURPHY EXPLORATION & PRODUCTION CO.	OCS-EPA-R4009	FL	1381	213111	5/15/2012	DRILL FLOOR AND CREW QUARTERS ELECTRICAL GENERATORS	17.11	DIESEL	6,789	HP	NO_x	10102	USE OF ENGINE WITH TURBO CHARGER WITH AFTER COOLER, AN ENHANCED WORK PRACTICE POWER MANAGEMENT, NOX EMISSIONS MAINTENANCE SYSTEM, AND GOOD COMBUSTION AND MAINTENANCE PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR EACH ENGINE.	26	G/KW-H	BACT-PSD
FL-0348	MURPHY EXPLORATION & PRODUCTION CO.	OCS-EPA-R4009	FL	1381	213111	5/15/2012	EMERGENCY ELECTRICAL GENERATOR	17.11	DIESEL	1,100	HP	NO_x	10102	USE OF GOOD COMBUSTION AND MAINTENANCE PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THIS ENGINE.	0.22	TONS	BACT-PSD
FL-0350	ANADARKO PETROLEUM, INC DIAMOND BLACKHAWK DRILLING PROJECT	OCS-EPA-R4019	FL	1381	213111	12/31/2014	MAIN PROPULSION GENERATOR ENGINES	17.11	DIESEL	0		NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE MOST RECENT MANUFACTURER'S SPECIFICATIONS ISSUED FOR THESE ENGINES AT THE TIME THAT THE ENGINES ARE OPERATING UNDER THIS PERMIT	0		BACT-PSD
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	1010524-001-AC	FL	4911	221112	7/27/2018	1,500 KW EMERGENCY DIESEL GENERATOR	17.11	ULSD	14.82	MMBTU/HR	NO_x	10102	OPERATE AND MAINTAIN THE ENGINE ACCORDING TO THE MANUFACTURER'S WRITTEN INSTRUCTIONS	6.4	G/KW-HOUR	BACT-PSD
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	1010524-001-AC	FL	4911	221112	7/27/2018	EMERGENCY FIRE PUMP ENGINE (347 HP)	17.21	ULSD	8,700	GAL/YR	NO_x	10102	OPERATE AND MAINTAIN THE ENGINE ACCORDING TO THE MANUFACTURER'S WRITTEN INSTRUCTIONS	4	G/KW-HR	BACT-PSD
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	1010524-003-AC (PSD-FL-444A)	FL	4911	221112	6/7/2021	1,500 KW EMERGENCY DIESEL GENERATOR	17.11	ULSD	14.82	MMBTU/HR	NO_x	10102		6.4	G/KW-HOUR	BACT-PSD

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Table 1. NOx RBLC Data For Diesel Generators

RBLCID	Facility Name	Permit No.	Facility State	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	1010524-003-AC (PSD-FL-444A)	FL	4911	221112	6/7/2021	EMERGENCY FIRE PUMP ENGINE (347 HP)	17.21	ULSD	2.46	MMBTU/HR	NO_x	10102		4	G/KW-HOUR	BACT-PSD
IA-0105	IOWA FERTILIZER COMPANY	12-219	IA	2873	325311	10/26/2012	EMERGENCY GENERATOR	17.11	DIESEL	142	GAL/HR	NO_x	10102	GOOD COMBUSTION PRACTICES	6	G/KW-H	BACT-PSD
IA-0105	IOWA FERTILIZER COMPANY	12-219	IA	2873	325311	10/26/2012	FIRE PUMP	17.21	DIESEL	14	GAL/HR	NO_x	10102	GOOD COMBUSTION PRACTICES	3.75	G/KW-H	BACT-PSD
IL-0114	CRONUS CHEMICALS, LLC	13060007	IL	2873	325311	9/5/2014	EMERGENCY GENERATOR	17.11	DISTILLATE OIL	3,755	HP	NO_x	10102	TIER IV STANDARDS FOR NON-ROAD ENGINES AT 40 CFR 1039.102, TABLE 7.	0.67	G/KW-H	BACT-PSD
IL-0114	CRONUS CHEMICALS, LLC	13060007	IL	2873	325311	9/5/2014	FIRE WATER PUMP ENGINE	17.21	DISTILLATE OIL	373	HP	NO_x	10102	TIER IV STANDARDS FOR NON-ROAD ENGINES AT 40 CFR 1039.102, TABLE 7.	3.5	G/KW-H	BACT-PSD
IL-0129	CPV THREE RIVERS ENERGY CENTER	16060032	IL	4911	221112	7/30/2018	EMERGENCY ENGINES	17.11	ULTRA-LOW SULFUR DIESEL	0		NO_x	10102		0		LAER
IL-0129	CPV THREE RIVERS ENERGY CENTER	16060032	IL	4911	221112	7/30/2018	FIRE WATER PUMP ENGINE	17.21	ULTRA-LOW SULFUR DIESEL	0		NO_x	10102		0		LAER
IL-0130	JACKSON ENERGY CENTER	17040013	IL	4911	221112	12/31/2018	FIRE WATER PUMP ENGINE	17.21	ULTRA-LOW SULFUR DIESEL	420	HP	NO_x	10102		4	G/KW-HR	LAER
IL-0130	JACKSON ENERGY CENTER	17040013	IL	4911	221112	12/31/2018	EMERGENCY ENGINE	17.11	ULTRA-LOW SULFUR DIESEL	1,500	KW	NO_x	10102		6.4	G/KW-HR	LAER
*IL-0133	LINCOLN LAND ENERGY CENTER	18040008	IL	4911	221112	7/29/2022	EMERGENCY ENGINES	17.11	ULTRA-LOW SULFUR DIESEL	1,250	KW	NO_x	10102		6.4	GRAMS	BACT-PSD
*IL-0133	LINCOLN LAND ENERGY CENTER	18040008	IL	4911	221112	7/29/2022	FIRE WATER PUMP ENGINE	17.21	ULTRA-LOW SULFUR DIESEL	320	HP	NO_x	10102		4	GRAMS	BACT-PSD
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	141-31003-00579	IN	4911	221112	12/3/2012	TWO (2) FIRE WATER PUMP DIESEL ENGINES	17.21	DIESEL	371	BHP, EACH	NO_x	10102	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	3	G/HP-H	BACT-PSD
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	141-31003-00579	IN	4911	221112	12/3/2012	TWO (2) EMERGENCY DIESEL GENERATORS	17.11	DIESEL	1,006	HP EACH	NO_x	10102	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	4.8	G/HP-H	BACT-PSD
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	141-31003-00579	IN	4911	221112	12/3/2012	EMERGENCY DIESEL GENERATOR	17.11	DIESEL	2,012	HP	NO_x	10102	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	4.8	G/HP-H	BACT-PSD
IN-0166	INDIANA GASIFICATION, LLC	T147-30464-00060	IN	4925	221210	6/27/2012	TWO (2) EMERGENCY GENERATORS	17.11	DIESEL	1,341	HP EACH	NO_x	10102	GOOD COMBUSTION PRACTICES AND LIMITED HOURS OF NON- EMERGENCY OPERATION	0		BACT-PSD
IN-0166	INDIANA GASIFICATION, LLC	T147-30464-00060	IN	4925	221210	6/27/2012	THREE (3) FIRE WATER PUMP ENGINES	17.11	DIESEL	575	HP EACH	NO_x	10102	GOOD COMBUSTION PRACTICES AND LIMITED HOURS OF NON- EMERGENCY OPERATION	0		BACT-PSD
IN-0173	MIDWEST FERTILIZER CORPORATION	129-33576-00059	IN	2873	325311	6/4/2014	DIESEL FIRED EMERGENCY GENERATOR	17.11	DIESEL	3,600	BHP	NO_x	10102	GOOD COMBUSTION PRACTICES	4.46	G/BHP-H	BACT-PSD
IN-0173	MIDWEST FERTILIZER CORPORATION	129-33576-00059	IN	2873	325311	6/4/2014	RAW WATER PUMP	17.21	DIESEL	500	HP	NO_x	10102	GOOD COMBUSTION PRACTICES	2.83	G/BHP-H	BACT-PSD
IN-0179	OHIO VALLEY RESOURCES, LLC	147-32322-00062	IN	2873	325311	9/25/2013	DIESEL-FIRED EMERGENCY GENERATOR	17.11	NO. 2 FUEL OIL	4,690	BHP	NO_x	10102	GOOD COMBUSTION PRACTICES	4.46	G/B-HP-H	BACT-PSD
IN-0179	OHIO VALLEY RESOURCES, LLC	147-32322-00062	IN	2873	325311	9/25/2013	DIESEL-FIRED EMERGENCY WATER PUMP	17.21	NO. 2 FUEL OIL	481	BHP	NO_x	10102	GOOD COMBUSTION PRACTICES	2.86	G/B-HP-H	BACT-PSD
IN-0180	MIDWEST FERTILIZER CORPORATION	129-33576-00059	IN	2873	325311	6/4/2014	DIESEL FIRED EMERGENCY GENERATOR	17.11	DIESEL	3,600	BHP	NO_x	10102	GOOD COMBUSTION PRACTICES	4.46	G/B-HP-H	BACT-PSD
IN-0180	MIDWEST FERTILIZER CORPORATION	129-33576-00059	IN	2873	325311	6/4/2014	RAW WATER PUMP	17.21	DIESEL	500	HP	NO_x	10102	GOOD COMBUSTION PRACTICES	2.83	G/B-HP-H	BACT-PSD
IN-0185	MAG PELLET LLC	181-33965-00054	IN	1011	212210	4/24/2014	DIESEL FIRE PUMP	17.11	DIESEL	300	HP	NO_x	10102		3	G/HP-H	BACT-PSD

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IN-0263	MIDWEST FERTILIZER COMPANY LLC	129-36943-00059	IN	2873	325311	3/23/2017	EMERGENCY GENERATORS (EU014A AND EU-014B)	17.11	DISTILLATE OIL	3,600	HP EACH	NO_x	10102	GOOD COMBUSTION PRACTICES	4.42	G/HP-H EACH	BACT-PSD
IN-0317	RIVERVIEW ENERGY CORPORATION	T147-39554-00065	IN	2911	324110	6/11/2019	EMERGENCY GENERATOR EU 6006	17.11	DIESEL	2,800	HP	NO_x	10102	TIER II DIESEL ENGINE	6.4	G/KWH	BACT-PSD
IN-0317	RIVERVIEW ENERGY CORPORATION	T147-39554-00065	IN	2911	324110	6/11/2019	EMERGENCY FIRE PUMP EU 6008	17.11	DIESEL	750	HP	NO_x	10102	ENGINE THAT COMPLIES WITH TABLE 4 TO SUBPART IIII OF PART 60	4	G/KWH	BACT-PSD
IN-0324	MIDWEST FERTILIZER COMPANY LLC	129-44510-00059	IN	2873	325311	5/6/2022	EMERGENCY GENERATOR EU 014A	17.11	DISTILLATE OIL	3,600	HP	NO_x	10102		4.42	G/HP-HR	BACT-PSD
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	C-10656	KS	4911	221112	3/18/2013	CATERPILLAR C18DITA DIESEL ENGINE GENERATOR	17.11	DISTILLATE OIL	900	BHP	NO_x	10102	UTILIZE EFFICIENT COMBUSTION/DESIGN TECHNOLOGY	14	LB/HR	BACT-PSD
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	C-10656	KS	4911	221112	3/18/2013	CUMMINS 6BTA 5.9F-1 DIESEL ENGINE FIRE PUMP	17.21	NO. 2 FUEL OIL	182	BHP	NO_x	10102	UTILIZE EFFICIENT COMBUSTION/DESIGN TECHNOLOGY	2	LB/HR	BACT-PSD
KY-0110	NUCOR STEEL BRANDENBURG	V-20-001	KY	3312	331111	7/23/2020	EP 10-02 - NORTH WATER SYSTEM EMERGENCY GENERATOR	17.11	DIESEL	2,922	HP	NO_x	10102	THIS EP IS REQUIRED TO HAVE A GOOD COMBUSTION AND OPERATING PRACTICES (GCOP) PLAN.	4.77	G/HP-HR	BACT-PSD
KY-0110	NUCOR STEEL BRANDENBURG	V-20-001	KY	3312	331111	7/23/2020	EP 10-03 - SOUTH WATER SYSTEM EMERGENCY GENERATOR	17.11	DIESEL	2,922	HP	NO_x	10102	THIS EP IS REQUIRED TO HAVE A GOOD COMBUSTION AND OPERATING PRACTICES (GCOP) PLAN.	4.77	G/HP-HR	BACT-PSD
KY-0110	NUCOR STEEL BRANDENBURG	V-20-001	KY	3312	331111	7/23/2020	EP 10-04 - EMERGENCY FIRE WATER PUMP	17.11	DIESEL	920	HP	NO_x	10102	THIS EP IS REQUIRED TO HAVE A GOOD COMBUSTION AND OPERATING PRACTICES (GCOP) PLAN.	4.77	G/HP-HR	BACT-PSD
KY-0110	NUCOR STEEL BRANDENBURG	V-20-001	KY	3312	331111	7/23/2020	EP 11-01 - MELT SHOP EMERGENCY GENERATOR	17.21	DIESEL	260	HP	NO_x	10102	THIS EP IS REQUIRED TO HAVE A GOOD COMBUSTION AND OPERATING PRACTICES (GCOP) PLAN.	2.98	G/HP-HR	BACT-PSD
KY-0110	NUCOR STEEL BRANDENBURG	V-20-001	KY	3312	331111	7/23/2020	EP 11-02 - REHEAT FURNACE EMERGENCY GENERATOR	17.21	DIESEL	190	HP	NO_x	10102	THIS EP IS REQUIRED TO HAVE A GOOD COMBUSTION AND OPERATING PRACTICES (GCOP) PLAN.	2.98	G/HP-HR	BACT-PSD
KY-0110	NUCOR STEEL BRANDENBURG	V-20-001	KY	3312	331111	7/23/2020	EP 10-07 - AIR SEPARATION PLANT EMERGENCY GENERATOR	17.11	DIESEL	700	HP	NO_x	10102	THIS EP IS REQUIRED TO HAVE A GOOD COMBUSTION AND OPERATING PRACTICES (GCOP) PLAN.	4.77	G/HP-HR	BACT-PSD
KY-0110	NUCOR STEEL BRANDENBURG	V-20-001	KY	3312	331111	7/23/2020	EP 10-01 - CASTER EMERGENCY GENERATOR	17.11	DIESEL	2,922	HP	NO_x	10102	THIS EP IS REQUIRED TO HAVE A GOOD COMBUSTION AND OPERATING PRACTICES (GCOP) PLAN.	4.77	G/HP-HR	BACT-PSD
KY-0110	NUCOR STEEL BRANDENBURG	V-20-001	KY	3312	331111	7/23/2020	EP 11-03 - ROLLING MILL EMERGENCY GENERATOR	17.21	DIESEL	440	HP	NO_x	10102	THIS EP IS REQUIRED TO HAVE A GOOD COMBUSTION AND OPERATING PRACTICES (GCOP) PLAN.	2.98	G/HP-HR	BACT-PSD
KY-0110	NUCOR STEEL BRANDENBURG	V-20-001	KY	3312	331111	7/23/2020	EP 11-04 - IT EMERGENCY GENERATOR	17.21	DIESEL	190	HP	NO_x	10102	THIS EP IS REQUIRED TO HAVE A GOOD COMBUSTION AND OPERATING PRACTICES (GCOP) PLAN.	2.98	G/HP-HR	BACT-PSD
KY-0110	NUCOR STEEL BRANDENBURG	V-20-001	KY	3312	331111	7/23/2020	EP 11-05 - RADIO TOWER EMERGENCY GENERATOR	17.21	DIESEL	61	HP	NO_x	10102	THIS EP IS REQUIRED TO HAVE A GOOD COMBUSTION AND OPERATING PRACTICES (GCOP) PLAN.	3.5	G/HP-HR	BACT-PSD
KY-0115	NUCOR STEEL GALLATIN, LLC	V-20-015	KY	3316	331111	4/19/2021	NEW PUMP HOUSE (XB13) EMERGENCY GENERATOR #1 (EP 08-05)	17.11	DIESEL	2,922	HP	NO_x	10102	THE PERMITTEE MUST DEVELOP A GOOD COMBUSTION AND OPERATING PRACTICES (GCOP) PLAN	0		BACT-PSD
KY-0115	NUCOR STEEL GALLATIN, LLC	V-20-015	KY	3316	331111	4/19/2021	TUNNEL FURNACE EMERGENCY GENERATOR (EP 08-06)	17.11	DIESEL	2,937	HP	NO_x	10102	THE PERMITTEE MUST DEVELOP A GOOD COMBUSTION AND OPERATING PRACTICES (GCOP) PLAN	0		BACT-PSD
KY-0115	NUCOR STEEL GALLATIN, LLC	V-20-015	KY	3316	331111	4/19/2021	CASTER B EMERGENCY GENERATOR (EP 08-07)	17.11	DIESEL	2,937	HP	NO_x	10102	THE PERMITTEE MUST DEVELOP A GOOD COMBUSTION AND OPERATING PRACTICES (GCOP) PLAN	0		BACT-PSD
KY-0115	NUCOR STEEL GALLATIN, LLC	V-20-015	KY	3316	331111	4/19/2021	AIR SEPARATION UNIT EMERGENCY GENERATOR (EP 08-08)	17.11	DIESEL	700	HP	NO_x	10102	THE PERMITTEE MUST DEVELOP A GOOD COMBUSTION AND OPERATING PRACTICES (GCOP) PLAN	0		BACT-PSD
KY-0115	NUCOR STEEL GALLATIN, LLC	V-20-015	KY	3316	331111	4/19/2021	COLD MILL COMPLEX EMERGENCY GENERATOR (EP 09-05)	17.21	DIESEL	350	HP	NO_x	10102	THE PERMITTEE MUST DEVELOP A GOOD COMBUSTION AND OPERATING PRACTICES (GCOP) PLAN	0		BACT-PSD

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RBLCID	Facility Name	Permit No.	Facility State	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
LA-0292	HOLBROOK COMPRESSOR STATION	PSD-LA-769(M-1)	LA	4922	486210	1/22/2016	EMERGENCY GENERATORS NO. 1 &; NO. 2	17.11	DIESEL	1,341	HP	NO_x	10102	GOOD EQUIPMENT DESIGN, PROPER COMBUSTION TECHNIQUES, USE OF LOW SULFUR FUEL, AND COMPLIANCE WITH 40 CFR 60 SUBPART IIII	14.16	LB/HR	BACT-PSD
LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	PSD-LA-779	LA	2821	325211	5/23/2014	EMERGENCY DIESEL GENERATORS (EQTS 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, &; 1202)	17.11	DIESEL	2,682	HP	NO_x	10102	COMPLIANCE WITH 40 CFR 60 SUBPART IIII; OPERATING THE ENGINE IN ACCORDANCE WITH THE ENGINE MANUFACTURER'S INSTRUCTIONS AND/OR WRITTEN PROCEDURES (CONSISTENT WITH SAFE OPERATION) DESIGNED TO MAXIMIZE COMBUSTION EFFICIENCY AND MINIMIZE FUEL USAGE.	27.37	LB/HR	BACT-PSD
LA-0305	LAKE CHARLES METHANOL FACILITY	PSD-LA-803(M1)	LA	2869	325199	6/30/2016	DIESEL ENGINES (EMERGENCY)	17.11	DIESEL	4,023	HP	NO_x	10102	COMPLYING WITH 40 CFR 60 SUBPART IIII	0		BACT-PSD
LA-0307	MAGNOLIA LNG FACILITY	PSD-LA-792	LA	4922	221210	3/21/2016	DIESEL ENGINES	17.11	DIESEL	0		NO_x	10102	GOOD COMBUSTION PRACTICES, USE ULTRA LOW SULFUR DIESEL, AND COMPLY WITH 40 CFR 60 SUBPART IIII	0		BACT-PSD
LA-0308	MORGAN CITY POWER PLANT	PSD-LA-767	LA	4911	221112	9/26/2013	2000 KW DIESEL FIRED EMERGENCY GENERATOR ENGINE	17.11	DIESEL	20.4	MMBTU/HR	NO_x	10102	GOOD COMBUSTION AND MAINTENANCE PRACTICES, AND COMPLIANCE WITH NSPS 40 CFR 60 SUBPART IIII	33.07	LB/H	BACT-PSD
LA-0308	MORGAN CITY POWER PLANT	PSD-LA-767	LA	4911	221112	9/26/2013	380 HP DIESEL FIRED PUMP ENGINE	17.21	DIESEL	2.3	MMBTU/HR	NO_x	10102	GOOD COMBUSTION AND MAINTENANCE PRACTICES, AND COMPLIANCE WITH NSPS 40 CFR 60 SUBPART IIII	2.92	LB/H	BACT-PSD
LA-0309	BENTELER STEEL TUBE FACILITY	PSD-LA-774(M1)	LA	3312	331111	6/4/2015	FIRE WATER PUMP ENGINES	17.21	DIESEL	288	HP EACH	NO_x	10102	COMPLYING WITH 40 CFR 60 SUBPART IIII	3	G/BHP-HR	BACT-PSD
LA-0309	BENTELER STEEL TUBE FACILITY	PSD-LA-774(M1)	LA	3312	331111	6/4/2015	EMERGENCY GENERATOR ENGINES	17.11	DIESEL	2,922	HP EACH	NO_x	10102	COMPLYING WITH 40 CFR 60 SUBPART IIII	6.4	G/KW-HR	BACT-PSD
*LA-0312	ST. JAMES METHANOL PLANT	PSD-LA-780(M-1)	LA	2869	325998	6/30/2017	DFP1-13 - DIESEL FIRE PUMP ENGINE (EQT0013)	17.11	DIESEL	650	HP	NO_x	10102	COMPLIANCE WITH NSPS SUBPART IIII	6.6	LB/HR	BACT-PSD
*LA-0312	ST. JAMES METHANOL PLANT	PSD-LA-780(M-1)	LA	2869	325998	6/30/2017	DEG1-13 - DIESEL FIRED EMERGENCY GENERATOR ENGINE (EQT0012)	17.11	DIESEL	1,474	HP	NO_x	10102	COMPLIANCE WITH NSPS SUBPART IIII	19.23	LB/HR	BACT-PSD
LA-0313	ST. CHARLES POWER STATION	PSD-LA-804	LA	4911	221112	8/31/2016	SCPS EMERGENCY DIESEL GENERATOR 1	17.11	DIESEL	2,584	HP	NO_x	10102	COMPLIANCE WITH NESHAP 40 CFR 63 SUBPART ZZZZ AND NSPS 40 CFR 60 SUBPART IIII, AND GOOD COMBUSTION PRACTICES (USE OF ULTRA-LOW SULFUR DIESEL FUEL).	27.34	LB/H	BACT-PSD
LA-0313	ST. CHARLES POWER STATION	PSD-LA-804	LA	4911	221112	8/31/2016	SCPS EMERGENCY DIESEL FIREWATER PUMP 1	17.21	DIESEL	282	HP	NO_x	10102	COMPLIANCE WITH NESHAP 40 CFR 63 SUBPART ZZZZ AND NSPS 40 CFR 60 SUBPART IIII, AND GOOD COMBUSTION PRACTICES (USE OF ULTRA-LOW SULFUR DIESEL FUEL).	1.87	LB/H	BACT-PSD
*LA-0315	G2G PLANT	PSD-LA-781	LA	2869	325110	5/23/2014	EMERGENCY DIESEL GENERATOR 1	17.11	DIESEL	5,364	HP	NO_x	10102	COMPLIANCE WITH 40 CFR 60 SUBPART IIII AND 40 CFR 63 SUBPART ZZZZ	52.58	LB/H	BACT-PSD
*LA-0315	G2G PLANT	PSD-LA-781	LA	2869	325110	5/23/2014	EMERGENCY DIESEL GENERATOR 2	17.11	DIESEL	5,364	HP	NO_x	10102	COMPLIANCE WITH 40 CFR 60 SUBPART IIII AND 40 CFR 63 SUBPART ZZZZ	52.58	LB/H	BACT-PSD
*LA-0315	G2G PLANT	PSD-LA-781	LA	2869	325110	5/23/2014	FIRE PUMP DIESEL ENGINE 1	17.11	DIESEL	751	HP	NO_x	10102	COMPLIANCE WITH 40 CFR 60 SUBPART IIII AND 40 CFR 63 SUBPART ZZZZ	4.6	LB/H	BACT-PSD
*LA-0315	G2G PLANT	PSD-LA-781	LA	2869	325110	5/23/2014	FIRE PUMP DIESEL ENGINE 2	17.11	DIESEL	751	HP	NO_x	10102	COMPLIANCE WITH 40 CFR 60 SUBPART IIII AND 40 CFR 63 SUBPART ZZZZ	4.6	LB/H	BACT-PSD
LA-0316	CAMERON LNG FACILITY	PSD-LA-766(M3)	LA	4922	221210	2/17/2017	FIRE WATER PUMP ENGINES (8 UNITS)	17.21	DIESEL	460	HP	NO_x	10102-44-0	COMPLYING WITH 40 CFR 60 SUBPART IIII	0		BACT-PSD
LA-0316	CAMERON LNG FACILITY	PSD-LA-766(M3)	LA	4922	221210	2/17/2017	EMERGENCY GENERATOR ENGINES (6 UNITS)	17.11	DIESEL	3,353	HP	NO_x	10102	COMPLYING WITH 40 CFR 60 SUBPART IIII	0		BACT-PSD
LA-0317	METHANEX - GEISMAR METHANOL PLANT	PSD-LA-761(M4)	LA	2869	325199	12/22/2016	EMERGENCY GENERATOR ENGINES (4 UNITS)	17.11	DIESEL	0		NO_x	10102	COMPLYING WITH 40 CFR 60 SUBPART IIII AND 40 CFR 63 SUBPART ZZZZ	0		BACT-PSD

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LA-0317	METHANEX - GEISMAR METHANOL PLANT	PSD-LA-761(M4)	LA	2869	325199	12/22/2016	FIRE WATER PUMP ENGINES (4 UNITS)	17.11	DIESEL	896	HP EACH	NO_x	10102	COMPLYING WITH 40 CFR 60 SUBPART IIII AND 40 CFR 63 SUBPART ZZZZ	0		BACT-PSD
LA-0323	MONSANTO LULING PLANT	PSD-LA-890	LA	2879	325320	1/9/2017	FIRE WATER DIESEL PUMP NO. 3 ENGINE	17.11	DIESEL	600	HP	NO_x	10102	PROPER OPERATION AND LIMITS ON HOURS OPERATION FOR EMERGENCY ENGINES AND COMPLIANCE WITH 40 CFR 60 SUBPART IIII	0		BACT-PSD
LA-0323	MONSANTO LULING PLANT	PSD-LA-890	LA	2879	325320	1/9/2017	FIRE WATER DIESEL PUMP NO. 4 ENGINE	17.11	DIESEL	600	HP	NO_x	10102	PROPER OPERATION AND LIMITS ON HOURS OF OPERATION FOR EMERGENCY ENGINES AND COMPLIANCE WITH 40 CFR 60 SUBPART IIII	0		BACT-PSD
LA-0323	MONSANTO LULING PLANT	PSD-LA-890	LA	2879	325320	1/9/2017	STANDBY GENERATOR NO. 9 ENGINE	17.21	DIESEL	400	HP	NO_x	10102	PROPER OPERATION AND LIMITS ON HOURS OF OPERATION FOR EMERGENCY ENGINES AND COMPLIANCE WITH 40 CFR 60 SUBPART IIII	0		BACT-PSD
LA-0331	CALCASIEU PASS LNG PROJECT	PDS-LA-805	LA	4925	221210	9/21/2018	FIRE WATER PUMPS	17.11	DIESEL	634	KW	NO_x	10102	GOOD COMBUSTION AND OPERATING PRACTICES.	3.1	G/HP-H	BACT-PSD
LA-0331	CALCASIEU PASS LNG PROJECT	PDS-LA-805	LA	4925	221210	9/21/2018	LARGE EMERGENCY ENGINES (50KW)	17.11	DIESEL	5,364	HP	NO_x	10102	GOOD COMBUSTION AND OPERATING PRACTICES	5.6	G/KW-H	BACT-PSD
LA-0364	FG LA COMPLEX	PSD-LA-812	LA	2869	325110	1/6/2020	EMERGENCY GENERATOR DIESEL ENGINES	17.11	DIESEL	550	HP	NO_x	10102	COMPLIANCE WITH THE LIMITATIONS IMPOSED BY 40 CFR 63 SUBPART IIII AND OPERATING THE ENGINE IN ACCORDANCE WITH THE ENGINE MANUFACTURER'S INSTRUCTIONS AND/OR WRITTEN PROCEDURES DESIGNED TO MAXIMIZE COMBUSTION EFFICIENCY AND MINIMIZE FUEL USAGE.	0		BACT-PSD
LA-0364	FG LA COMPLEX	PSD-LA-812	LA	2869	325110	1/6/2020	EMERGENCY FIRE WATER PUMPS	17.11	DIESEL	550	HP	NO_x	10102	COMPLIANCE WITH THE LIMITATIONS IMPOSED BY 40 CFR 63 SUBPART IIII AND OPERATING THE ENGINE IN ACCORDANCE WITH THE ENGINE MANUFACTURER'S INSTRUCTIONS AND/OR WRITTEN PROCEDURES DESIGNED TO MAXIMIZE COMBUSTION EFFICIENCY AND MINIMIZE FUEL USAGE.	0		BACT-PSD
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PSD-LA-709(M-4)	LA	2821	325211	5/4/2021	PVC EMERGENCY COMBUSTION EQUIPMENT A	17.21	DIESEL	450	HP	NO_x	10102	GOOD COMBUSTION PRACTICES/GASEOUS FUEL BURNING.	6.9	G/HP-HR	BACT-PSD
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PSD-LA-709(M-4)	LA	2821	325211	5/4/2021	PVC EMERGENCY COMBUSTION EQUIPMENT 2A AND 2B	17.21	DIESEL	300	HP	NO_x	10102	COMPLIANCE WITH 40 CFR 60 SUBPART IIII.	0.4	G/KW-HR	BACT-PSD
LA-0382	BIG LAKE FUELS METHANOL PLANT	PSD-LA-781(M1)	LA	2869	325199	4/25/2019	EMERGENCY ENGINES (EQT0014 - EQT0017)	17.11	DIESEL	0		NO_x	10102	COMPLY WITH STANDARDS OF 40 CFR 60 SUBPART IIII	0		BACT-PSD
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	PSD-LA-838	LA	4925	486210	9/3/2020	EMERGENCY ENGINES (EQT0011 - EQT0016)	17.11	DIESEL	0		NO_x	10102	COMPLY WITH 40 CFR 60 SUBPART IIII	0		BACT-PSD
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	NE-12-022	MA	4911	221112	1/30/2014	EMERGENCY ENGINE/GENERATOR	17.11	ULSD	7.4	MMBTU/HR	NO_x	10102		4.8	GM/BHP-H	LAER
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	NE-12-022	MA	4911	221112	1/30/2014	FIRE PUMP ENGINE	17.21	ULSD	2.7	MMBTU/HR	NO_x	10102		3	GM/BHP-H	LAER
MA-0043	MIT CENTRAL UTILITY PLANT	NE-15-018	MA	8221	611310	6/21/2017	COLD START ENGINE	17.11	ULSD	19.04	MMBTU/HR	NO_x	10102		35.09	LB/HR	OTHER CASE-BY-CASE
MD-0042	WILDCAT POINT GENERATION FACILITY	CPCN CASE NO. 9327	MD	4911	221119	4/8/2014	EMERGENCY GENERATOR 1	17.11	ULTRA-LOW SULFUR DIESEL	2,250	KW	NO_x	10102	LIMITED OPERATING HOURS, USE OF ULTRA-LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	4.8	G/HP-H	LAER

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MD-0042	WILDCAT POINT GENERATION FACILITY	CPCN CASE NO. 9327	MD	4911	221119	4/8/2014	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	17.21	ULTRA-LOW SULFUR DIESEL	477	HP	NO_x	10102	LIMITED OPERATING HOURS, USE OF ULTRA-LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	3	G/HP-H	LAER
MD-0043	PERRYMAN GENERATING STATION	PSC CASE NO. 9136	MD	4911	221119	7/1/2014	EMERGENCY GENERATOR	17.11	ULTRA-LOW SULFUR DIESEL	1,300	HP	NO_x	10102	GOOD COMBUSTION PRACTICES, LIMITED HOURS OF OPERATION, AND EXCLUSIVE USE OF ULSD	4.8	G/HP-H	LAER
MD-0043	PERRYMAN GENERATING STATION	PSC CASE NO. 9136	MD	4911	221119	7/1/2014	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	17.21	ULTRA-LOW SULFUR DIESEL	350	HP	NO_x	10102	GOOD COMBUSTION PRACTICES, LIMITED HOURS OF OPERATION, AND EXCLUSIVE USE OF ULSD	3	G/HP-H	LAER
MD-0044	COVE POINT LNG TERMINAL	PSC CASE NO. 9318	MD	4911	221119	6/9/2014	EMERGENCY GENERATOR	17.11	ULTRA-LOW SULFUR DIESEL	1,550	HP	NO_x	10102	GOOD COMBUSTION PRACTICES AND DESIGNED TO ACHIEVE EMISSION LIMIT	4.8	G/HP-H	LAER
MD-0044	COVE POINT LNG TERMINAL	PSC CASE NO. 9318	MD	4911	221119	6/9/2014	5 EMERGENCY FIRE WATER PUMP ENGINES	17.21	ULTRA-LOW SULFUR DIESEL	350	HP	NO_x	10102	GOOD COMBUSTION PRACTICES AND DESIGNED TO ACHIEVE EMISSION LIMIT	3	G/HP-H	LAER
MI-0394	WARREN TECHNICAL CENTER	160-11	MI	3711	336211	2/29/2012	FOUR (4) EMERGENCY GENERATORS	17.11	DIESEL	2,280	KW	NO_x	10102	NO ADD-ON CONTROLS, BUT IGNITION TIMING RETARDATION (ITR) IS GOOD DESIGN. ENGINES ARE TUNED FOR LOW-NOX OPERATION VERSUS LOW CO OPERATION.	6.93	G/KW-H	BACT-PSD
MI-0394	WARREN TECHNICAL CENTER	160-11	MI	3711	336211	2/29/2012	NINE (9) DRUPS EMERGENCY GENERATORS	17.11	DIESEL	3,010	KW	NO_x	10102	NO ADD-ON CONTROLS, BUT IGNITION TIMING RETARDATION (ITR) IS GOOD DESIGN. ENGINES ARE TUNED FOR LOW-NOX OPERATION VERSUS LOW CO OPERATION.	5.98	G/KW-H	BACT-PSD
MI-0395	WARREN TECHNICAL CENTER	160-11A	MI	3711	336211	7/13/2012	NINE (9) DRUPS EMERGENCY GENERATORS	17.11	DIESEL	3,010	KW	NO_x	10102	NO ADD-ON CONTROLS, BUT IGNITION TIMING RETARDATION (ITR) IS GOOD DESIGN. ENGINES ARE TUNED FOR LOW-NOX OPERATION VERSUS LOW CO OPERATION.	5.98	G/KW-H	BACT-PSD
MI-0395	WARREN TECHNICAL CENTER	160-11A	MI	3711	336211	7/13/2012	FOUR (4) EMERGENCY GENERATORS	17.11	DIESEL	2,500	KW	NO_x	10102	NO ADD-ON CONTROL, BUT IGNITION TIMING RETARDATION (ITR) IS GOOD DESIGN. ENGINES ARE TUNED FOR LOW-NOX OPERATION VERSUS LOW CO OPERATION.	7.13	G/KW-H	BACT-PSD
MI-0406	RENAISSANCE POWER LLC	51-13	MI	4911	221112	11/1/2013	FG-EMGEN7-8; TWO (2) 1,000KW DIESEL-FUELED EMERGENCY RECIPROCATING INTERNAL COMBUSTION ENGINES	17.11	DIESEL	1,000	KW	NO_x	10102	GOOD COMBUSTION PRACTICES	4.8	G/B-HP-H	BACT-PSD
MI-0418	WARREN TECHNICAL CENTER	160-11B	MI	3711	336211	1/14/2015	FG-BACK UP GENS (NINE (9) DRUPS EMERGENCY ENGINES)	17.11	DIESEL	3,490	KW	NO_x	10102	NO ADD-ON CONTROLS, BUT INJECTION TIMING RETARDATION (ITR) IS GOOD DESIGN. ENGINES ARE TUNED FOR LOW-NOX OPERATION VERSUS LOW CO OPERATION.	8	G/KW-H	BACT-PSD
MI-0418	WARREN TECHNICAL CENTER	160-11B	MI	3711	336211	1/14/2015	FOUR (4) EMERGENCY ENGINES IN FG- BACK UP GENS	17.11	DIESEL	2,710	KW	NO_x	10102	NO ADD-ON CONTROLS, BUT INJECTION TIMING RETARDATION (ITR) IS GOOD DESIGN. ENGINES ARE TUNED FOR LOW-NOX OPERATION VERSUS LOW CO OPERATION.	7.13	G/KW-H	BACT-PSD
MI-0421	GRAYLING PARTICLEBOARD	59-16	MI	2493	321219	8/26/2016	EMERGENCY DIESEL GENERATOR ENGINE (EU EMRG RICE IN FG RICE)	17.11	DIESEL	500	H/YR	NO_x	10102	CERTIFIED ENGINES, LIMITED OPERATING HOURS.	22.6	LB/H	BACT-PSD
MI-0421	GRAYLING PARTICLEBOARD	59-16	MI	2493	321219	8/26/2016	DIESEL FIRE PUMP ENGINE (EU FIRE PUMP IN FG RICE)	17.11	DIESEL	500	H/YR	NO_x	10102	CERTIFIED ENGINES, LIMITED OPERATING HOURS.	3.53	LB/H	BACT-PSD
MI-0423	INDECK NILES, LLC	75-16	MI	4911	221112	1/4/2017	EU EM ENGINE (DIESEL FUEL EMERGENCY ENGINE)	17.11	DIESEL	22.68	MMBTU/HR	NO_x	10102	GOOD COMBUSTION PRACTICES AND MEETING NSPS IIII REQUIREMENTS.	6.4	G/KW-H	BACT-PSD
MI-0423	INDECK NILES, LLC	75-16	MI	4911	221112	1/4/2017	EU FP ENGINE (EMERGENCY ENGINE--DIESEL FIRE PUMP)	17.21	DIESEL	1.66	MMBTU/HR	NO_x	10102	GOOD COMBUSTION PRACTICES AND MEETING NSPS SUBPART IIII REQUIREMENTS.	3	G/BHP-H	BACT-PSD
MI-0425	GRAYLING PARTICLEBOARD	59-16A	MI	2493	321219	5/9/2017	EU EMRG RICE 1 IN FG RICE (EMERGENCY DIESEL GENERATOR ENGINE)	17.11	DIESEL	500	H/YR	NO_x	10102	CERTIFIED ENGINES, LIMITED OPERATING HOURS.	21.2	LB/H	BACT-PSD

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RBLCID	Facility Name	Permit No.	Facility State	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
MI-0425	GRAYLING PARTICLEBOARD	59-16A	MI	2493	321219	5/9/2017	EU EMRG RICE 2 IN FG RICE (EMERGENCY DIESEL GENERATOR ENGINE)	17.11	DIESEL	500	H/YR	NO_x	10102	CERTIFIED ENGINES, LIMITED OPERATING HOURS	4.4	LB/H	BACT-PSD
MI-0425	GRAYLING PARTICLEBOARD	59-16A	MI	2493	321219	5/9/2017	EU FIRE PUMP IN FGRICE (DIESEL FIRE PUMP ENGINE)	17.11	DIESEL	500	H/YR	NO_x	10102	CERTIFIED ENGINES. LIMITED OPERATING HOURS.	3.53	LB/H	BACT-PSD
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	167-17 AND 168-17	MI	4911	221112	6/29/2018	EU FP ENGINE (SOUTH PLANT): FIRE PUMP ENGINE	17.21	DIESEL	300	HP	NO_x	10102	GOOD COMBUSTION PRACTICES AND MEETING NSPS SUBPART IIII REQUIREMENTS.	3	G/BHP-H	BACT-PSD
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	167-17 AND 168-17	MI	4911	221112	6/29/2018	EU EM ENGINE (NORTH PLANT): EMERGENCY ENGINE	17.11	DIESEL	1,341	HP	NO_x	10102	GOOD COMBUSTION PRACTICES AND MEETING NSPS SUBPART IIII REQUIREMENTS.	6.4	G/KW-H	BACT-PSD
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	167-17 AND 168-17	MI	4911	221112	6/29/2018	EU FP ENGINE (NORTH PLANT): FIRE PUMP ENGINE	17.21	DIESEL	300	HP	NO_x	10102	GOOD COMBUSTION PRACTICES AND MEETING NSPS SUBPART IIII REQUIREMENTS.	3	G/BHP-H	BACT-PSD
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	167-17 AND 168-17	MI	4911	221112	6/29/2018	EU EM ENGINE (SOUTH PLANT): EMERGENCY ENGINE	17.11	DIESEL	1,341	HP	NO_x	10102	GOOD COMBUSTION PRACTICES AND MEETING NSPS IIII REQUIREMENTS.	6.4	G/KW-H	BACT-PSD
MI-0434	FLAT ROCK ASSEMBLY PLANT	122-17	MI	8741	561110	3/22/2018	EU ENGINE 01 THROUGH EU ENGINE 08	17.11	DIESEL	3,633	BHP	NO_x	10102	GOOD COMBUSTION PRACTICES.	6.4	G/KW-H	BACT-PSD
MI-0434	FLAT ROCK ASSEMBLY PLANT	122-17	MI	8741	561110	3/22/2018	EU FIRE PUMPINGS (2 EMERGENCY FIRE PUMP ENGINES)	17.21	DIESEL	250	BHP	NO_x	10102	GOOD COMBUSTION PRACTICES.	3	G/B-HP-H	BACT-PSD
MI-0434	FLAT ROCK ASSEMBLY PLANT	122-17	MI	8741	561110	3/22/2018	EU LIFE SAFETY ENG - ONE DIESEL-FUELED EMERGENCY ENGINE/GENERATOR	17.21	DIESEL	500	KW	NO_x	10102	GOOD COMBUSTION PRACTICES.	4	G/KW-H	BACT-PSD
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	19-18	MI	4911	221112	7/16/2018	EU EM ENGINE: EMERGENCY ENGINE	17.11	DIESEL	2	MW	NO_x	10102	STATE OF THE ART COMBUSTION DESIGN.	6.4	G/KW-H	BACT-PSD
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	19-18	MI	4911	221112	7/16/2018	EU FP ENGINE: FIRE PUMP ENGINE	17.21	DIESEL	399	BHP	NO_x	10102	STATE OF THE ART COMBUSTION DESIGN.	4	G/KW-H	BACT-PSD
MI-0441	LBWL–ERICKSON STATION	74-18	MI	4911	221112	12/21/2018	EU EMG D1–A 1500 HP DIESEL FUELED EMERGENCY ENGINE	17.11	DIESEL	1,500	HP	NO_x	10102	GOOD COMBUSTION PRACTICES AND WILL BE NSPS COMPLIANT.	6.4	G/KW-H	BACT-PSD
MI-0441	LBWL–ERICKSON STATION	74-18	MI	4911	221112	12/21/2018	EU EMG D2–A 6000 HP DIESEL FUEL FIRED EMERGENCY ENGINE	17.11	DIESEL	6,000	HP	NO_x	10102	GOOD COMBUSTION PRACTICES AND WILL BE NSPS COMPLIANT.	6.4	G/KW-H	BACT-PSD
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	210-18	MI	4911	221112	8/21/2019	FG EM ENGINE	17.11	DIESEL	1,100	KW	NO_x	10102		5.3	G/HP-H	BACT-PSD
*MI-0445	INDECK NILES, LLC	75-16B	MI	4911	221112	11/26/2019	EU FP ENGINE (EMERGENCY ENGINE-DIESEL FIRE PUMP	17.21	DIESEL	1.66	MMBTU/HR	NO_x	10102	GOOD COMBUSTION PRACTICES AND MEETING NSPS SUBPART IIII REQUIREMENTS	3	G/BHP-H	BACT-PSD
*MI-0445	INDECK NILES, LLC	75-16B	MI	4911	221112	11/26/2019	EU EM ENGINE (DIESEL FUEL EMERGENCY ENGINE)	17.11	DIESEL	22.68	MMBTU/HR	NO_x	10102	GOOD COMBUSTION PRACTICES AND MEETING NSPS SUBPART IIII REQUIREMENTS	6.4	G/KW-H	BACT-PSD
MI-0448	GRAYLING PARTICLEBOARD	59-16E	MI	2493	321219	12/18/2020	EMERGENCY DIESEL GENERATOR ENGINE (EU EMRG RICE 1 IN FG RICE)	17.11	DIESEL	500	H/YR	NO_x	10102	CERTIFIED ENGINES, LIMITED OPERATING HOURS	21.2	LB/H	BACT-PSD
MI-0448	GRAYLING PARTICLEBOARD	59-16E	MI	2493	321219	12/18/2020	EMERGENCY DIESEL GENERATOR ENGINE (EU EMRG RICE 2 IN FGRICE)	17.11	DIESEL	500	H/YR	NO_x	10102	CERTIFIED ENGINES, LIMITED OPERATING HOURS	4.4	LB/H	BACT-PSD
MI-0448	GRAYLING PARTICLEBOARD	59-16E	MI	2493	321219	12/18/2020	DIESEL FIRE PUMP ENGINE (EU FIRE PUMP IN FG RICE)	17.11	DIESEL	500	H/YR	NO_x	10102	CERTIFIED ENGINES, LIMITED OPERATING HOURS	3.53	LB/H	BACT-PSD
NJ-0079	WOODBRIDGE ENERGY CENTER	18940 - BOP110003	NJ	4911	221112	7/25/2012	EMERGENCY GENERATOR	17.11	ULTRA-LOW SULFUR DIESEL	100	H/YR	NO_x	10102	USE OF ULSD DIESEL OIL	21.16	LB/H	LAER
NJ-0080	HESS NEWARK ENERGY CENTER	08857/BOP110001	NJ	4911	221112	11/1/2012	EMERGENCY GENERATOR	17.11	ULSD	200	H/YR	NO_x	10102	USE OF ULTRA LOW SULFUR DIESEL (ULSD) A CLEAN FUEL	18.53	LB/H	LAER

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NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	18068/BOP150001	NJ	4911	221112	3/10/2016	DIESEL FIRED EMERGENCY GENERATOR	17.11	ULSD	44	H/YR	NO_x	10102	USE OF ULTRA LOW SULFUR DIESEL A CLEAN BURNING FUEL.	42.3	LB/H	LAER
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	18068/BOP150001	NJ	4911	221112	3/10/2016	EMERGENCY DIESEL FIRE PUMP	17.21	ULSD	100	H/YR	NO_x	10102	USE OF ULSD A CLEAN BURNING FUEL, AND LIMITED HOURS OF OPERATION	1.7	LB/H	LAER
NY-0103	CRICKET VALLEY ENERGY CENTER	3-1326-00275/00009	NY	4911	221112	2/3/2016	BLACK START GENERATOR	17.11	ULTRA-LOW SULFUR DIESEL	3,000	KW	NO_x	10102	GENERATOR EQUIPPED WITH SELECTIVE CATALYTIC REDUCTION. COMPLIANCE DEMONSTRATED WITH VENDOR EMISSION CERTIFICATION AND ADHERENCE TO VENDOR-SPECIFIED MAINTENANCE RECOMMENDATIONS.	2.11	G/BHP-H	LAER
NY-0103	CRICKET VALLEY ENERGY CENTER	3-1326-00275/00009	NY	4911	221112	2/3/2016	EMERGENCY FIRE PUMP	17.21	ULTRA-LOW SULFUR DIESEL	460	HP	NO_x	10102	COMPLIANCE DEMONSTRATED WITH VENDOR EMISSION CERTIFICATION AND ADHERENCE TO VENDOR-SPECIFIED MAINTENANCE RECOMMENDATIONS.	2.6	G/BHP-H	LAER
OH-0352	OREGON CLEAN ENERGY CENTER	P0110840	OH	4931	221112	6/18/2013	EMERGENCY FIRE PUMP ENGINE	17.21	DIESEL	300	HP	NO_x	10102	PURCHASED CERTIFIED TO THE STANDARDS IN NSPS SUBPART IIII	1.7	LB/H	BACT-PSD
OH-0352	OREGON CLEAN ENERGY CENTER	P0110840	OH	4931	221112	6/18/2013	EMERGENCY GENERATOR	17.11	DIESEL	2,250	KW	NO_x	10102	PURCHASED CERTIFIED TO THE STANDARDS IN NSPS SUBPART IIII	27.8	LB/H	BACT-PSD
OH-0360	CARROLL COUNTY ENERGY	P0113762	OH	4911	221112	11/5/2013	EMERGENCY GENERATOR (P003)	17.11	DIESEL	1,112	KW	NO_x	10102	PURCHASED CERTIFIED TO THE STANDARDS IN NSPS SUBPART IIII	13.74	LB/H	BACT-PSD
OH-0360	CARROLL COUNTY ENERGY	P0113762	OH	4911	221112	11/5/2013	EMERGENCY FIRE PUMP ENGINE (P004)	17.21	DIESEL	400	HP	NO_x	10102	PURCHASED CERTIFIED TO THE STANDARDS IN NSPS SUBPART IIII	2.3	LB/H	BACT-PSD
OH-0363	NTE OHIO, LLC	P0116610	OH	4911	221112	11/5/2014	EMERGENCY GENERATOR (P002)	17.11	DIESEL	1,100	KW	NO_x	10102	EMERGENCY OPERATION ONLY, < 500 HOURS/YEAR EACH FOR MAINTENANCE CHECKS AND READINESS TESTING DESIGNED TO MEET NSPS SUBPART IIII	29.01	LB/H	BACT-PSD
OH-0363	NTE OHIO, LLC	P0116610	OH	4911	221112	11/5/2014	EMERGENCY FIRE PUMP ENGINE (P003)	17.21	DIESEL	260	HP	NO_x	10102	EMERGENCY OPERATION ONLY, < 500 HOURS/YEAR EACH FOR MAINTENANCE CHECKS AND READINESS TESTING DESIGNED TO MEET NSPS SUBPART IIII	1.72	LB/H	BACT-PSD
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	P0117655	OH	4911	221112	8/25/2015	EMERGENCY FIRE PUMP ENGINE (P004)	17.21	DIESEL	140	HP	NO_x	10102	STATE-OF-THE-ART COMBUSTION DESIGN	0.81	LB/H	BACT-PSD
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	P0117655	OH	4911	221112	8/25/2015	EMERGENCY GENERATOR (P003)	17.11	DIESEL	2,346	HP	NO_x	10102	STATE-OF-THE-ART COMBUSTION DESIGN	21.6	LB/H	BACT-PSD
OH-0367	SOUTH FIELD ENERGY LLC	P0119495	OH	4911	221112	9/23/2016	EMERGENCY FIRE PUMP ENGINE (P004)	17.21	DIESEL	311	HP	NO_x	10102	STATE-OF-THE-ART COMBUSTION DESIGN	1.79	LB/H	BACT-PSD
OH-0367	SOUTH FIELD ENERGY LLC	P0119495	OH	4911	221112	9/23/2016	EMERGENCY GENERATOR (P003)	17.11	DIESEL	2,947	HP	NO_x	10102	STATE-OF-THE-ART COMBUSTION DESIGN	27.18	LB/H	BACT-PSD
OH-0368	PALLAS NITROGEN LLC	P0118959	OH	2873	325311	4/19/2017	EMERGENCY FIRE PUMP DIESEL ENGINE (P008)	17.21	DIESEL	460	HP	NO_x	10102	GOOD COMBUSTION CONTROL AND OPERATING PRACTICES AND ENGINES DESIGNED TO MEET THE STANDS OF 40 CFR PART 60, SUBPART IIII	0.3	LB/H	BACT-PSD
OH-0368	PALLAS NITROGEN LLC	P0118959	OH	2873	325311	4/19/2017	EMERGENCY GENERATOR (P009)	17.11	DIESEL	5,000	HP	NO_x	10102	GOOD COMBUSTION CONTROL AND OPERATING PRACTICES AND ENGINES DESIGNED TO MEET THE STANDS OF 40 CFR PART 60, SUBPART IIII	5.5	LB/H	BACT-PSD
OH-0370	TRUMBULL ENERGY CENTER	P0122331	OH	4911	221112	9/7/2017	EMERGENCY GENERATOR (P003)	17.11	DIESEL	1,529	HP	NO_x	10102	STATE-OF-THE-ART COMBUSTION DESIGN	16.07	LB/H	BACT-PSD
OH-0370	TRUMBULL ENERGY CENTER	P0122331	OH	4911	221112	9/7/2017	EMERGENCY FIRE PUMP ENGINE (P004)	17.21	DIESEL	300	HP	NO_x	10102	STATE-OF-THE-ART COMBUSTION DESIGN	1.97	LB/H	BACT-PSD

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OH-0372	OREGON ENERGY CENTER	P0121049	OH	4911	221112	9/27/2017	EMERGENCY GENERATOR (P003)	17.11	DIESEL	1,529	HP	NO_x	10102	STATE-OF-THE-ART COMBUSTION DESIGN	16.1	LB/H	BACT-PSD
OH-0372	OREGON ENERGY CENTER	P0121049	OH	4911	221112	9/27/2017	EMERGENCY FIRE PUMP ENGINE (P004)	17.21	DIESEL	300	HP	NO_x	10102	STATE-OF-THE-ART COMBUSTION DESIGN	1.97	LB/H	BACT-PSD
OH-0374	GUERNSEY POWER STATION LLC	P0122594	OH	4911	221112	10/23/2017	EMERGENCY GENERATORS (2 IDENTICAL, P004 AND P005)	17.11	DIESEL	2,206	HP	NO_x	10102	CERTIFIED TO THE MEET THE EMISSIONS STANDARDS IN 40 CFR 89.112 AND 89.113 PURSUANT TO 40 CFR 60.4205(B) AND 60.4202(A)(2). GOOD COMBUSTION PRACTICES PER THE MANUFACTURER'S OPERATING MANUAL.	23.21	LB/H	BACT-PSD
OH-0374	GUERNSEY POWER STATION LLC	P0122594	OH	4911	221112	10/23/2017	EMERGENCY FIRE PUMP (P006)	17.21	DIESEL	410	HP	NO_x	10102	CERTIFIED TO THE MEET THE EMISSIONS STANDARDS IN TABLE 4 OF 40 CFR PART 60, SUBPART IIII. GOOD COMBUSTION PRACTICES PER THE MANUFACTURER'S OPERATING MANUAL	2.7	LB/H	BACT-PSD
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	P0122829	OH	4911	221112	11/7/2017	EMERGENCY DIESEL GENERATOR ENGINE (P001)	17.11	DIESEL	2,206	HP	NO_x	10102	GOOD COMBUSTION DESIGN	24.71	LB/H	BACT-PSD
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	P0122829	OH	4911	221112	11/7/2017	EMERGENCY DIESEL FIRE PUMP ENGINE (P002)	17.11	DIESEL	700	HP	NO_x	10102	GOOD COMBUSTION DESIGN	4.97	LB/H	BACT-PSD
OH-0376	IRONUNITS LLC - TOLEDO HBI	P0123395	OH	3312	331111	2/9/2018	EMERGENCY DIESEL-FUELED FIRE PUMP (P006)	17.21	DIESEL	250	HP	NO_x	10102	COMPLY WITH NSPS 40 CFR 60 SUBPART IIII	1.6	LB/H	BACT-PSD
OH-0376	IRONUNITS LLC - TOLEDO HBI	P0123395	OH	3312	331111	2/9/2018	EMERGENCY DIESEL-FIRED GENERATOR (P007)	17.11	DIESEL	2,682	HP	NO_x	10102	COMPLY WITH NSPS 40 CFR 60 SUBPART IIII	28.2	LB/H	BACT-PSD
OH-0377	HARRISON POWER	P0122266	OH	4911	221112	4/19/2018	EMERGENCY DIESEL GENERATOR (P003)	17.11	DIESEL	1,860	HP	NO_x	10102	GOOD COMBUSTION PRACTICES (ULSD) AND COMPLIANCE WITH 40 CFR PART 60, SUBPART IIII	19.68	LB/H	BACT-PSD
OH-0377	HARRISON POWER	P0122266	OH	4911	221112	4/19/2018	EMERGENCY FIRE PUMP (P004)	17.21	DIESEL	320	HP	NO_x	10102	GOOD COMBUSTION PRACTICES (ULSD) AND COMPLIANCE WITH 40 CFR PART 60, SUBPART IIII	2.12	LB/H	BACT-PSD
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	P0124972	OH	2869	325110	12/21/2018	FIREWATER PUMPS (P005 AND P006)	17.21	DIESEL	402	HP	NO_x	10102	CERTIFIED TO THE MEET THE EMISSIONS STANDARDS IN TABLE 4 OF 40 CFR PART 60, SUBPART IIII AND EMPLOY GOOD COMBUSTION PRACTICES PER THE MANUFACTURER'S OPERATING MANUAL	2.64	LB/H	BACT-PSD
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	P0124972	OH	2869	325110	12/21/2018	EMERGENCY DIESEL-FIRED GENERATOR ENGINE (P007)	17.11	DIESEL	3,353	HP	NO_x	10102	CERTIFIED TO THE MEET THE EMISSIONS STANDARDS IN TABLE 4 OF 40 CFR PART 60, SUBPART IIII, SHALL EMPLOY GOOD COMBUSTION PRACTICES PER THE MANUFACTURER'S OPERATING MANUAL	37.41	LB/H	BACT-PSD
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	P0124972	OH	2869	325110	12/21/2018	1,000 KW EMERGENCY GENERATORS (P008 - P010)	17.11	DIESEL	1,341	HP	NO_x	10102	CERTIFIED TO THE MEET THE EMISSIONS STANDARDS IN TABLE 4 OF 40 CFR PART 60, SUBPART IIII, SHALL EMPLOY GOOD COMBUSTION PRACTICES PER THE MANUFACTURER'S OPERATING MANUAL	14.96	LB/H	BACT-PSD
OH-0379	PETMIN USA INCORPORATED	P0125024	OH	3312	331111	2/6/2019	BLACK START GENERATOR (P007)	17.21	DIESEL	158	HP	NO_x	10102	TIER IV ENGINE TIER IV NSPS STANDARDS CERTIFIED BY ENGINE MANUFACTURER.	0.104	LB/H	BACT-PSD
OH-0379	PETMIN USA INCORPORATED	P0125024	OH	3312	331111	2/6/2019	EMERGENCY GENERATORS (P005 AND P006)	17.11	DIESEL	3,131	HP	NO_x	10102	TIER IV ENGINE TIER IV NSPS STANDARDS CERTIFIED BY ENGINE MANUFACTURER.	3.45	LB/H	BACT-PSD

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OH-0383	PETMIN USA INCORPORATED	P0127678	OH	3312	331111	7/17/2020	DIESEL-FIRED EMERGENCY FIRE PUMPS (2) (P009 AND P010)	17.11	DIESEL	3,131	HP	NO_x	10102	TIER IV NSPS STANDARDS CERTIFIED BY ENGINE MANUFACTURER.	0		BACT-PSD
OK-0145	BROKEN BOW OSB MILL	2003-099-C(M-3)PSD	OK	2493	321219	6/25/2012	EMERG DIESEL GEN, FIRE PUMP, RAIL STEAM GEN, AIR MAKEUP UNITS	17.11	DIESEL	0		NO_x	10102		0		BACT-PSD
OK-0154	MOORELAND GENERATING STA	2008-302-C (M-1) PSD	OK	4911	221112	7/2/2013	DIESEL-FIRED EMERGENCY GENERATOR ENGINE	17.11	DIESEL	1,341	HP	NO_x	10102	COMBUSTION CONTROL	0.011	LB/HP-HR	BACT-PSD
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	08-00045A	PA	491	221112	10/10/2012	EMERGENCY GENERATOR	17.11	DIESEL	0		NO_x	10102		4.93	G/B-HP-H	OTHER CASE-BY-CASE
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	08-00045A	PA	491	221112	10/10/2012	FIRE PUMP	17.21	DIESEL	0		NO_x	10102		2.6	G/B-HP-H	OTHER CASE-BY-CASE
*PA-0282	JOHNSON MATTHEY INC/CATALYTIC SYSTEMS DIV	15-0027K	PA	3714	336399	6/1/2012	ENGINE TEST CELLS (6)	19.9	GASOLINE/DIESEL	27	GAL/HR	NO_x	10102		11	T/YR	OTHER CASE-BY-CASE
*PA-0282	JOHNSON MATTHEY INC/CATALYTIC SYSTEMS DIV	15-0027K	PA	3714	336399	6/1/2012	650-KW BACKUP DIESEL GENERATOR	17.11	DIESEL	45.8	GAL/HR	NO_x	10102		6.9	G/HP-H	OTHER CASE-BY-CASE
PA-0291	HICKORY RUN ENERGY STATION	37-337A	PA	4911	221112	4/23/2013	EMERGENCY FIREWATER PUMP	17.21	ULTRA LOW SULFUR DISTILLATE	3.25	MMBTU/HR	NO_x	10102		1.86	LB/H	OTHER CASE-BY-CASE
PA-0291	HICKORY RUN ENERGY STATION	37-337A	PA	4911	221112	4/23/2013	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DISTILLATE	7.8	MMBTU/HR	NO_x	10102		9.89	LB/H	OTHER CASE-BY-CASE
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	35-00069A	PA	4911	221112	12/23/2015	FIRE PUMP ENGINE	17.21	ULTRA-LOW SULFUR DIESEL	15	GAL/HR	NO_x	10102		3	GM/HP-HR	LAER
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	35-00069A	PA	4911	221112	12/23/2015	2000 KW EMERGENCY GENERATOR	17.11	ULTRA-LOW SULFUR DIESEL	0		NO_x	10102		5.45	GM/HP-HR	LAER
PA-0310	CPV FAIRVIEW ENERGY CENTER	11-00536A	PA	4911	221112	9/2/2016	EMERGENCY GENERATOR ENGINES	17.11	ULSD	0		NO_x	10102		4.8	G/BHP-HR	LAER
PA-0310	CPV FAIRVIEW ENERGY CENTER	11-00536A	PA	4911	221112	9/2/2016	EMERGENCY FIRE PUMP ENGINE	17.21	ULSD	0		NO_x	10102		3	G/BHP-HR	LAER
PA-0311	MOXIE FREEDOM GENERATION PLANT	40-00129A	PA	4911	221112	9/1/2015	FIRE PUMP ENGINE	17.11	DIESEL	0		NO_x	10102		3	G/HP-HR	LAER
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	R2-PSD 1	PR	4953	221119	4/10/2014	EMERGENCY DIESEL FIRE PUMP	17.21	ULSD FUEL OIL # 2	0		NO_x	10102		2.85	G/B-HP-H	BACT-PSD
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	R2-PSD 1	PR	4953	221119	4/10/2014	EMERGENCY DIESEL GENERATOR	17.11	ULSD FUEL OIL # 2	0		NO_x	10102		2.85	G/B-HP-H	BACT-PSD
SC-0113	PYRAMAX CERAMICS, LLC	0160-0023	SC	3295	327992	2/8/2012	EMERGENCY ENGINE 1 THRU 8	17.21	DIESEL	29	HP	NO_x	10102	PURCHASE OF CERTIFIED ENGINE.	7.5	GR/KW-H	BACT-PSD
SC-0113	PYRAMAX CERAMICS, LLC	0160-0023	SC	3295	327992	2/8/2012	FIRE PUMP	17.21	DIESEL	500	HP	NO_x	10102	PURCHASE OF CERTIFIED ENGINE BASED ON NSPS, SUBPART IIII.	4	GR/KW-H	BACT-PSD
SC-0113	PYRAMAX CERAMICS, LLC	0160-0023	SC	3295	327992	2/8/2012	EMERGENCY GENERATORS 1 THRU 8	17.11	DIESEL	757	HP	NO_x	10102	ENGINES MUST BE CERTIFIED TO COMPLY WITH NSPS, SUBPART IIII.	4	GR/KW-H	BACT-PSD

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Table 1. NOx RBLC Data For Diesel Generators

RBLCID	Facility Name	Permit No.	Facility State	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
TX-0671	PROJECT JUMBO	108446/PSDTX1352	TX	2821	325211	12/1/2014	ENGINES	17.11	ULTRA-LOW SULFUR DIESEL	0		NO_x	10102	EACH EMERGENCY GENERATOR'S EMISSION FACTOR IS BASED ON EPA'S TIER 2 STANDARDS AT 40CFR89.112 FOR NOX	5.43	G/KW-H	BACT-PSD
TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	118239, N200	TX	2813	325311	4/1/2015	EMERGENCY DIESEL GENERATOR	17.11	DIESEL	1,500	HP	NO_x	10102	MINIMIZED HOURS OF OPERATIONS TIER II ENGINE	0.0218	G/HP HR	LAER
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	PSDTX1546 AND GHGPSDTX186	TX	2869	325110	2/6/2020	EMERGENCY GENERATOR	17.11	DIESEL	0		NO_x	10102	TIER 4 EXHAUST EMISSION STANDARDS SPECIFIED IN 40 CFR Â§ 1039.101, LIMITED TO 100 HOURS PER YEAR OF NON-EMERGENCY OPERATION	0		BACT-PSD
TX-0879	MOTIVA PORT ARTHUR TERMINAL	7238 AND PSDTX1548	TX	5171	424710	2/19/2020	EMERGENCY FIREWATER ENGINE	17.11	ULTRA-LOW SULFUR DIESEL	0		NO_x	10102	MEETING THE REQUIREMENTS OF 40 CFR PART 60, SUBPART IIII. FIRING ULTRA-LOW SULFUR DIESEL FUEL (NO MORE THAN 15 PPM SULFUR BY WEIGHT). LIMITED TO 100 HRS/YR OF NON-EMERGENCY OPERATION. HAVE A NON-RESETTABLE RUNTIME METER.	0		BACT-PSD
TX-0888	ORANGE POLYETHYLENE PLANT	155952 PSDTX1556 GHGPSDTX192	TX	2821	325211	4/23/2020	EMERGENCY GENERATORS &; FIRE WATER PUMP ENGINES	17.11	ULTRA-LOW SULFUR DIESEL	0		NO_x	10102	WELL-DESIGNED AND PROPERLY MAINTAINED ENGINES AND EACH LIMITED TO 100 HOURS PER YEAR OF NON-EMERGENCY USE.	0		BACT-PSD
TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX	156571, PSDTX1564, GHGPSDTX195	TX	2869	325199	9/9/2020	EMERGENCY GENERATOR	17.11	ULTRA-LOW SULFUR DIESEL	0		NO_x	10102	100 HOURS OPERATIONS, TIER 4 EXHAUST EMISSION STANDARDS SPECIFIED IN 40 CFR Â§ 1039.101	0		BACT-PSD
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	160299, PSDTX1576, GHGPSDTX200	TX	2869	325998	9/16/2020	EMERGENCY GENERATOR	17.11	ULTRA-LOW SULFUR DIESEL	0		NO_x	10102	LIMITED TO 100 HOURS PER YEAR OF NON-EMERGENCY OPERATION	0		BACT-PSD
TX-0933	NACERO PENWELL FACILITY	164137 PSDTX1594 GHGPSDTX207	TX	2869	325110	11/17/2021	EMERGENCY GENERATORS	17.11	ULTRA-LOW SULFUR DIESEL (NO MORE THAN 15)	0		NO_x	10102	LIMITED TO 100 HOURS PER YEAR OF NON-EMERGENCY OPERATION. EPA TIER 2 (40 CFR Â§ 1039.101) EXHAUST EMISSION STANDARDS	0		BACT-PSD
VA-0325	GREENSVILLE POWER STATION	52525	VA	4911	221112	6/17/2016	DIESEL-FIRED EMERGENCY GENERATOR 3000 KW (1)	17.11	DIESEL FUEL	0		NO_x	10102	GOOD COMBUSTION PRACTICES/MAINTENANCE	6.4	G/KW	N/A
VA-0325	GREENSVILLE POWER STATION	52525	VA	4911	221112	6/17/2016	DIESEL-FIRED WATER PUMP 376 BPH (1)	17.21	DIESEL FUEL	0		NO_x	10102	GOOD COMBUSTION PRACTICES/MAINTENANCE	0		N/A
VA-0328	C4GT, LLC	52588	VA	4911	221112	4/26/2018	EMERGENCY DIESEL GEN	17.11	ULTRA-LOW SULFUR DIESEL	500	H/YR	NO_x	10102	GOOD COMBUSTION PRACTICES AND THE USE OF ULTRA LOW SULFUR DIESEL (S15 ULSD) FUEL OIL WITH A MAXIMUM SULFUR CONTENT OF 15 PPMW.	4.8	G/HP H	BACT-PSD
VA-0328	C4GT, LLC	52588	VA	4911	221112	4/26/2018	EMERGENCY FIRE WATER PUMP	17.21	ULTRA-LOW SULFUR DIESEL	500	HR/YR	NO_x	10102	GOOD COMBUSTION PRACTICES AND THE USE OF ULTRA LOW SULFUR DIESEL (S15 ULSD) FUEL OIL WITH A MAXIMUM SULFUR CONTENT OF 15 PPMW.	3	G/HP-HR	BACT-PSD
VA-0332	CHICKAHOMINY POWER LLC	52610-1	VA	4911	221112	6/24/2019	EMERGENCY DIESEL GENERATOR - 300 KW	17.11	ULTRA-LOW SULFUR DIESEL	500	H/YR	NO_x	10102	GOOD COMBUSTION PRACTICES, HIGH EFFICIENCY DESIGN, AND THE USE OF ULTRA LOW SULFUR DIESEL (S15 ULSD) FUEL OIL WITH A MAXIMUM SULFUR CONTENT OF 15 PPMW.	4.8	G/HP-H	BACT-PSD
VA-0332	CHICKAHOMINY POWER LLC	52610-1	VA	4911	221112	6/24/2019	EMEGENCY FIRE WATER PUMP	17.21	ULTRA-LOW SULFUR DIESEL	500	HR/YR	NO_x	10102	GOOD COMBUSTION PRACTICES, HIGH EFFICIENCY DESIGN, AND THE USE OF ULTRA LOW SULFUR DIESEL (S15 ULSD) FUEL OIL WITH A MAXIMUM SULFUR CONTENT OF 15 PPMW.	3	G/HP-HR	BACT-PSD
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	18-JJW-017	WI	4911	221112	4/24/2018	DIESEL-FIRED EMERGENCY GENERATORS	17.11	DIESEL	0		NO_x	10102	THE USE OF ULTRA-LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	5.36	G/KWH	BACT-PSD

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Table 1. NOx RBLC Data For Diesel Generators

RBLCID	Facility Name	Permit No.	Facility State	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
WI-0286	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	18-JJW-022	WI	3679	334419	4/24/2018	P42 -DIESEL FIRED EMERGENCY GENERATOR	17.11	DIESEL	0		NO_x	10102	GOOD COMBUSTION PRACTICES, THE USE OF AN ENGINE TURBOCHARGER AND AFTERCOOLER.	5.36	G/KWH	BACT-PSD
WI-0300	NEMADJI TRAIL ENERGY CENTER	18-MMC-168	WI	4911	221121	9/1/2020	EMERGENCY DIESEL FIRE PUMP (P06)	17.21	DIESEL	282	HP	NO_x	10102	OPERATION LIMITED TO 500 HOURS/YEAR AND SHALL BE OPERATED AND MAINTAINED ACCORDING TO THE MANUFACTURER'S RECOMMENDATIONS.	3	G/HP-H	BACT-PSD
WI-0300	NEMADJI TRAIL ENERGY CENTER	18-MMC-168	WI	4911	221121	9/1/2020	EMERGENCY DIESEL GENERATOR (P07)	17.11	DIESEL	1,490	HP	NO_x	10102	OPERATION LIMITED TO 500 HOURS/YEAR AND OPERATE AND MAINTAIN ACCORDING TO THE MANUFACTURER'S RECOMMENDATIONS.	4.8	G/HP-H	BACT-PSD
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	R14-0030	WV	4911	221112	11/21/2014	EMERGENCY GENERATOR	17.11	DIESEL	2,015.7	HP	NO_x	10102		0		BACT-PSD
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	R14-0030	WV	4911	221112	11/21/2014	FIRE PUMP ENGINE	17.21	DIESEL	251	HP	NO_x	10102		0		BACT-PSD
WV-0027	INWOOD	R14-0015M	WV	3296	327993	9/15/2017	EMERGENCY GENERATOR - ESDG14	17.11	ULSD	900	BHP	NO_x	10102	ENGINE DESIGN	4.77	G/HP-HR	BACT-PSD
*WV-0033	MAIDSVILLE	R14-0038	WV	4911	221112	1/5/2022	EMERGENCY GENERATOR	17.11	ULSD	2,100	HP	NO_x	10102	COMBUSTION CONTROL (RETARDED TIMING AND/OR LEAN BURN)	24.6	LB/HR	BACT-PSD
*WV-0033	MAIDSVILLE	R14-0038	WV	4911	221112	1/5/2022	FIRE WATER PUMP	17.11	ULSD	240	BHP	NO_x	10102	COMBUSTION CONTROL (RETARDED TIMING AND/OR LEAN BURN)	1.59	LB/HR	BACT-PSD
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	CT-12636	WY	491	221112	8/28/2012	DIESEL EMERGENCY GENERATOR (EP15)	17.11	ULTRA-LOW SULFUR DIESEL	839	HP	NO_x	10102	EPA TIER 2 RATED	0		BACT-PSD
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	CT-12636	WY	491	221112	8/28/2012	DIESEL FIRE PUMP ENGINE (EP16)	17.21	ULTRA-LOW SULFUR DIESEL	327	HP	NO_x	10102	EPA TIER 3 RATED	0		BACT-PSD

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Table 2. NOx RBLC Data for Boilers

RBLCID	Facility Name	Permit No.	Facility State	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
AK-0083	KENAI NITROGEN OPERATIONS	AQ0083CPT06	AK	2873	325311	1/6/2015	THREE (3) PACKAGE BOILERS	12.31	NATURAL GAS	243	MMBTU/HR	NO_x	ULTRA LOW NOX BURNERS	0.01	LB/MMBTU	BACT-PSD
AK-0083	KENAI NITROGEN OPERATIONS	AQ0083CPT06	AK	2873	325311	1/6/2015	FIVE (5) WASTE HEAT BOILERS	13.31	NATURAL GAS	50	MMBTU/HR	NO_x	SELECTIVE CATALYTIC REDUCTION	7	PPMV	BACT-PSD
AL-0307	ALLOYS PLANT	701-0007-X121-X126	AL	3353	331315	10/9/2015	PACKAGE BOILER	13.31	NATURAL GAS	17.5	MMBTU/HR	NO_x	LOW NOX BURNER FLUE GAS RECIRCULATION GCP	30	PPMVD	BACT-PSD
AL-0307	ALLOYS PLANT	701-0007-X121-X126	AL	3353	331315	10/9/2015	2 CALP LINE BOILERS	13.31	NATURAL GAS	24.59	MMBTU/HR	NO_x	LOW NOX BURNER FLUE GAS RECIRCULATION (FGR) GOOD COMBUSTION PRACTICES (GCP)	30	PPMVD	BACT-PSD
AL-0328	PLANT BARRY	503-1001	AL	4911	221112	11/9/2020	90.5 MMBTU/HR AUX BOILER	13.31	NATURAL GAS	90.5	MMBTU/HR	NO_x		0.011	LB/MMBTU	BACT-PSD
AR-0140	BIG RIVER STEEL LLC	2305-AOP-R0	AR	3312	331111	9/18/2013	BOILER, VACUUM DEGASSER	13.29	NATURAL GAS	51.2	MMBTU/HR	NO_x	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE LOW NOX BURNERS	0.035	LB/MMBTU	BACT-PSD
AR-0140	BIG RIVER STEEL LLC	2305-AOP-R0	AR	3312	331111	9/18/2013	BOILER, PICKLE LINE	13.31	NATURAL GAS	67	MMBTU/HR	NO_x	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU	BACT-PSD
AR-0140	BIG RIVER STEEL LLC	2305-AOP-R0	AR	3312	331111	9/18/2013	BOILERS SN-26 AND 27, GALVANIZING LINE	13.31	NATURAL GAS	24.5	MMBTU/HR	NO_x	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU	BACT-PSD
AR-0155	BIG RIVER STEEL LLC	2035-AOP-R2	AR	3312	331111	11/7/2018	BOILER, VACUUM DEGASSER	13.29	NATURAL GAS	88.7	MMBTU/HR	NO_x	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE LOW NOX BURNERS	0.035	LB/MMBTU	BACT-PSD
AR-0155	BIG RIVER STEEL LLC	2035-AOP-R2	AR	3312	331111	11/7/2018	BOILER, PICKLE LINE	13.31	NATURAL GAS	53.7	MMBTU/HR	NO_x	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU	BACT-PSD
AR-0155	BIG RIVER STEEL LLC	2035-AOP-R2	AR	3312	331111	11/7/2018	BOILER SN-26, GALVANIZING LINE	13.31	NATURAL GAS	53.7	MMBTU/HR	NO_x	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU	BACT-PSD
AR-0159	BIG RIVER STEEL LLC	2305-AOP-R4	AR	3312	331111	4/5/2019	BOILER, PICKLE LINE	13.31	NATURAL GAS	0		NO_x	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU	BACT-PSD
AR-0159	BIG RIVER STEEL LLC	2305-AOP-R4	AR	3312	331111	4/5/2019	BOILER, ANNEALING PICKLE LINE	13.31	NATURAL GAS	0		NO_x	LOW NOX BURNERS, COMBUSTION OF CLEAN FUEL, AND GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU	BACT-PSD
AR-0159	BIG RIVER STEEL LLC	2305-AOP-R4	AR	3312	331111	4/5/2019	BOILERS SN-26 AND SN- 27, GALVANIZING LINE	13.31	NATURAL GAS	0		NO_x	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU	BACT-PSD
AR-0167	LION OIL COMPANY	0868-AOP-R18	AR	2911	324110	12/1/2020	SN-803 - #4 PRE-FLASH COLUMN REBOILER	13.31	NATURAL GAS	40	MMBTU/HR	NO_x	ULTRA-LOW NOX BURNERS AND GOOD COMBUSTION PRACTICE	1.9	LB/HR	BACT-PSD
AR-0167	LION OIL COMPANY	0868-AOP-R18	AR	2911	324110	12/1/2020	SN-805 - #4 PRE-FLASH REBOILER	13.31	NATURAL GAS	75	MMBTU/HR	NO_x	ULTRA-LOW NOX BURNERS AND GOOD COMBUSTION PRACTICE	3.5	LB/HR	BACT-PSD

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Table 2. NOx RBLC Data for Boilers

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AR-0167	LION OIL COMPANY	0868-AOP-R18	AR	2911	324110	12/1/2020	SN-810 - #9 HYDROTREATER FURNACE/REBOILER	13.31	NATURAL GAS	70	MMBTU/HR	NO_x		12.7	LB/HR	BACT-PSD
AR-0171	NUCOR STEEL ARKANSAS	1139-AOP-R24	AR	3312	331111	2/14/2019	SN-142 VACUUM DEGASSER BOILER	13.31	NATURAL GAS	50.4	MMBTU/HR	NO_x	LOW NOX BURNERS	0.035	LB/MMBTU	BACT-PSD
AR-0171	NUCOR STEEL ARKANSAS	1139-AOP-R24	AR	3312	331111	2/14/2019	SN-233 GALVANIZING LINE BOILERS	13.31	NATURAL GAS	15	MMBTU/HR EACH	NO_x	LOW NOX BURNERS	0.1	LB/MMBTU	BACT-PSD
AR-0172	NUCOR STEEL ARKANSAS	1139-AOP-R26	AR	3312	331111	9/1/2021	SN-202, 203, 204 PICKLE LINE BOILERS	13.31	NATURAL GAS	0		NO_x	LOW NOX BURNERS	0.035	LB/MMBTU	BACT-PSD
AR-0173	BIG RIVER STEEL LLC	2445-AOP-R0	AR	3462	331111	1/31/2022	PICKLE LINE BOILER	13.31	NATURAL GAS	53.7	MMBTU/HR	NO_x	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU	BACT-PSD
AR-0173	BIG RIVER STEEL LLC	2445-AOP-R0	AR	3462	331111	1/31/2022	GALVANIZING LINE BOILERS #1 AND #2	13.31	NATURAL GAS	53.7	MMBTU/HR	NO_x	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU	BACT-PSD
AR-0173	BIG RIVER STEEL LLC	2445-AOP-R0	AR	3462	331111	1/31/2022	PICKLE GALVANIZING LINE BOILER	13.31	NATURAL GAS	53.7	MMBTU/HR	NO_x	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU	BACT-PSD
CA-1189	PETROROCK-TUNNELL LEASE	ATC- 12949-01 (2)	CA	1311	211111	1/24/2012	BOILER	13.31	PROPANE, FIELD GAS, PUC NATURAL GAS	2	MMBTU/HR	NO_x	LOW NOX BURNER	20	PPMVD@3% O2	OTHER CASE-BY-CASE
CT-0159	CPV TOWANTIC, LLC	144-0025	CT	4911	221112	11/30/2015	AUX BOILER	13.31	NATURAL GAS	359.6	MMCF	NO_x	BOILER PERMIT DOES NOT SPECIFY ANY ADD ON CONTROL OTHER THAN ULTR-LOW NOX BURNER. UNIT MAY BE REQUIRED TO USE ADDITIONAL CONTROL OPTIONS TO MEET EMISSIONS LIMIT.	7	PPMVD @3% O2	LAER
FL-0335	SUWANNEE MILL	1210468-001-AC(PSD FL-417)	FL	2421	321113	9/5/2012	FOUR(4) NATURAL GAS BOILERS - 46 MMBTU/HOUR	13.31	NATURAL GAS	46	MMBTU/HR	NO_x	LOW NOX BURNER AND FLUE GAS RECIRCULATION	0.036	LB/MMBTU	BACT-PSD
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	0930117-001-AC	FL	4911	221112	3/9/2016	AUXILIARY BOILER, 99.8 MMBTU/HR	13.31	NATURAL GAS	99.8	MMBTU/HR	NO_x	LOW-NOX BURNERS	0.05	LB/MMBTU	BACT-PSD
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	1010524-001-AC	FL	4911	221112	7/27/2018	60 MMBTU/HOUR AUXILIARY BOILER	13.31	NATURAL GAS	60	MMBTU/HR	NO_x	LOW-NOX BURNERS	0.05	LB/MMBTU	BACT-PSD
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	1010524-003-AC (PSD-FL-444A)	FL	4911	221112	6/7/2021	60 MMBTU/HOUR AUXILIARY BOILER	13.31	NATURAL GAS	60	MMBTU/HR	NO_x	LOW-NOX BURNERS	0.05	LB/MMBTU	BACT-PSD

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IA-0107	MARSHALLTOWN GENERATING STATION	13-A-499-P	IA	4911	221112	4/14/2014	AUXILIARY BOILER	13.31	NATURAL GAS	60.1	MMBTU/HR	NO_x		0.013	LB/MMBTU	BACT-PSD
IL-0129	CPV THREE RIVERS ENERGY CENTER	16060032	IL	4911	221112	7/30/2018	AUXILIARY BOILER	13.31	NATURAL GAS	96	MMBTU/HR	NO_x	ULTRA-LOW NOX BURNERS AND FLUE GAS RECIRCULATION, AIR PREHEATER, AUTOMATED COMBUSTION MANAGEMENT SYSTEM WITH O2 TRIM SYSTEM AND AUTOMATED WATER BLOWDOWN, AND GOOD COMBUSTION PRACTICES.	0.011	LB/MMBTU	LAER
IL-0130	JACKSON ENERGY CENTER	17040013	IL	4911	221112	12/31/2018	AUXILIARY BOILER	13.31	NATURAL GAS	96	MMBTU/HR	NO_x	ULTRA LOW-NOX BURNERS AND FLUE GAS RECIRCULATION AIR PREHEATER, AUTOMATED COMBUSTION MANAGEMENT SYSTEMS, AUTOMATED WATER BLOWDOWN, GOOD COMBUSTION PRACTICES	0.01	LB/MMBTU	LAER
*IL-0133	LINCOLN LAND ENERGY CENTER	18040008	IL	4911	221112	7/29/2022	AUXILIARY BOILER	13.31	NATURAL GAS	80	MMBTU/HR	NO_x	ULTRA LOW-NOX BURNERS AND FLUE GAS RECIRCULATION, AIR PREHEATER, AUTOMATED COMBUSTION MANAGEMENT SYSTEM, WITH AN OXYGEN TRIM SYSTEM AND AN AUTOMATED WATER BLOWDOWN SYSTEM.	0.01	POUNDS/MM BTU	BACT-PSD
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	141-31003-00579	IN	4911	221112	12/3/2012	TWO (2) NATURAL GAS AUXILIARY BOILERS	13.31	NATURAL GAS	80	MMBTU/HR	NO_x	LOW NOX BURNER WITH FLUE GAS RECIRCULATION	0.032	LB/MMBTU	BACT-PSD
IN-0263	MIDWEST FERTILIZER COMPANY LLC	129-36943-00059	IN	2873	325311	3/23/2017	NATURAL GAS AUXILIARY BOILERS (EU-012A, EU- 012B, EU-012C)	12.31	NATURAL GAS	218.6	MMBTU/HR	NO_x	LOW NOX BURNERS WITH FLUE GAS RECIRCULATION AND GOOD COMBUSTION PRACTICES	20.4	LB/MMCF EACH	BACT-PSD
IN-0324	MIDWEST FERTILIZER COMPANY LLC	129-44510-00059	IN	2873	325311	5/6/2022	NATURAL GAS-FIRED AUXILIARY BOILERS EU 012A AND EU 012B	12.31	NATURAL GAS	218.6	MMBTU/HR	NO_x	THE NATURAL GAS-FIRED AUXILIARY BOILERS SHALL COMBUST NATURAL GAS	20.4	LB/MMCF	BACT-PSD
KY-0115	NUCOR STEEL GALLATIN, LLC	V-20-015	KY	3316	331111	4/19/2021	VACUUM DEGASSER BOILER (EP 20-13)	13.31	NATURAL GAS	50.4	MMBTU/HR	NO_x	THE PERMITTEE MUST DEVELOP A GOOD COMBUSTION AND OPERATING PRACTICES (GCOP) PLAN. ALSO EQUIPPED WITH LOW- NOX BURNERS.	35	LB/MMSCF	BACT-PSD

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KY-0115	NUCOR STEEL GALLATIN, LLC	V-20-015	KY	3316	331111	4/19/2021	PICKLE LINE #2 BOILER #1 & #2 (EP 21-04 & EP 21-05)	13.31	NATURAL GAS	18	MMBTU/HR EACH	NO_x	THE PERMITTEE MUST DEVELOP A GOOD COMBUSTION AND OPERATING PRACTICES (GCOP) PLAN. EQUIPPED WITH LOW-NOX BURNERS.	50	LB/MMSCF	BACT-PSD
LA-0305	LAKE CHARLES METHANOL FACILITY	PSD-LA-803(M1)	LA	2869	325199	6/30/2016	AUXILIARY BOILERS AND SUPERHEATERS	11.31	NATURAL GAS	0		NO_x	SCR	0.015	LBS/MM BTU	BACT-PSD
LA-0307	MAGNOLIA LNG FACILITY	PSD-LA-792	LA	4922	221210	3/21/2016	AUXILIARY BOILERS	12.31	NATURAL GAS	171	MMBTU/HR	NO_x	LOW NOX BURNERS	0		BACT-PSD
*LA-0315	G2G PLANT	PSD-LA-781	LA	2869	325110	5/23/2014	UTILITY BOILER 1	11.31	NATURAL GAS	656	MMBTU/HR	NO_x	SELECTIVE CATALYTIC REDUCTION (SCR)	3.94	LB/H	BACT-PSD
*LA-0315	G2G PLANT	PSD-LA-781	LA	2869	325110	5/23/2014	UTILITY BOILER 2	11.31	NATURAL GAS	656	MMBTU/HR	NO_x	SELECTIVE CATALYTIC REDUCTION (SCR)	3.94	LB/H	BACT-PSD
*LA-0315	G2G PLANT	PSD-LA-781	LA	2869	325110	5/23/2014	UTILITY BOILER 3	11.31	NATURAL GAS	656	MMBTU/HR	NO_x	SELECTIVE CATALYTIC REDUCTION (SCR)	3.94	LB/H	BACT-PSD
LA-0364	FG LA COMPLEX	PSD-LA-812	LA	2869	325110	1/6/2020	BOILERS	11.31	NATURAL GAS	1,200	MMBTU/HR	NO_x	SCR AND LNB	0.01	LB/MMBTU	BACT-PSD
LA-0364	FG LA COMPLEX	PSD-LA-812	LA	2869	325110	1/6/2020	PR WASTE HEAT BOILER	13.31	NATURAL GAS	94	MMBTU/HR	NO_x	SCR AND LNB	14.41	LB/H	BACT-PSD
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	NE-12-022	MA	4911	221112	1/30/2014	AUXILIARY BOILER	13.31	NATURAL GAS	80	MMBTU/HR	NO_x	ULTRA LOW NOX BURNERS	0.011	LB/MMBTU	LAER
MD-0041	CPV ST. CHARLES	PSC CASE NO. 9280	MD	4911	221119	4/23/2014	AUXILLARY BOILER	13.31	NATURAL GAS	93	MMBTU/HR	NO_x	EXCLUSIVE USE OF NATURAL GAS, ULTRA LOW-NOX BURNERS, AND FLUE GAS RECIRCULATION (FGR)	0.011	LB/MMBTU	LAER
MD-0042	WILDCAT POINT GENERATION FACILITY	CPCN CASE NO. 9327	MD	4911	221119	4/8/2014	AUXILLARY BOILER	13.31	NATURAL GAS	45	MMBTU/HR	NO_x	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.01	LB/MMBTU	LAER
MD-0045	MATTAWOMAN ENERGY CENTER	PSC CASE. NO. 9330	MD	4911	221119	11/13/2015	AUXILIARY BOILER	13.31	NATURAL GAS	42	MMBTU/HR	NO_x	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS, ULTRA LOW- NOX BURNERS, AND GOOD COMBUSTION PRACTICES	0.01	LB/MMBTU	BACT-PSD
MD-0046	KEYS ENERGY CENTER	PSC CASE NO. 9297	MD	4911	221119	10/31/2014	AUXILIARY BOILER	13.31	PIPELINE QUALITY NATURAL GAS	93	MMBTU/HR	NO_x	EFFICIENT BOILER DESIGN WITH ULTRA LOW NOX BURNER, EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS, AND APPLICATION OF GOOD COMBUSTION PRACTICES	0.01	LB/MMBTU	BACT-PSD

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RBLCID	Facility Name	Permit No.	Facility State	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
MI-0406	RENAISSANCE POWER LLC	51-13	MI	4911	221112	11/1/2013	EU-HEATER SC: NATURAL GAS-FIRED FUEL HEATER USED FOR HEATING NATURAL GAS PRIOR TO COMBUSTION IN THE CTGS. MISC. BOILERS, FURNACES, AND HEATERS	19.6	NATURAL GAS	20	MMBTU/HR	NO_x	GOOD COMBUSTION PRACTICES	0.15	LB/MMBTU	BACT-PSD
MI-0406	RENAISSANCE POWER LLC	51-13	MI	4911	221112	11/1/2013	FG-AUX BOILER 1-2; TWO (2) NATURAL GAS-FIRED AUXILIARY BOILERS.	13.31	NATURAL GAS	40	MMBTU/HR	NO_x	GOOD COMBUSTION PRACTICES.	0.035	LB/MMBTU	BACT-PSD
MI-0410	THETFORD GENERATING STATION	191-12	MI	4911	221112	7/25/2013	FG AUX BOILERS: TWO AUXILIARY BOILERS < 100 MMBTU/H HEAT INPUT EACH	13.31	NATURAL GAS	100	MMBTU/HR HEAT INPUT EACH	NO_x	LOW NOX BURNERS AND FLUE GAS RECIRCULATION.	0.05	LB/MMBTU	BACT-PSD
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	107-13	MI	4931	221112	12/4/2013	AUXILIARY BOILER B (EU AUX BOILERB)	13.31	NATURAL GAS	95	MMBTU/HR	NO_x	DRY LOW NOX BURNERS, FLUE GAS RECIRCULATION AND GOOD COMBUSTION PRACTICES.	0.05	LB/MMBTU	BACT-PSD
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	107-13	MI	4931	221112	12/4/2013	AUXILIARY BOILER A (EU AUX BOILERA)	13.31	NATURAL GAS	55	MMBTU/HR	NO_x	LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES	0.05	LB/MMBTU	BACT-PSD
MI-0420	DTE GAS COMPANY–MILFORD COMPRESSOR STATION	185-15	MI	4922	486210	6/3/2016	FG AUX BOILERS	13.31	NATURAL GAS	6	MMBTU/HR	NO_x	ULTRA LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES.	14	PPMVOL	BACT-PSD
MI-0423	INDECK NILES, LLC	75-16	MI	4911	221112	1/4/2017	EU AUX BOILER (AUXILIARY BOILER)	12.31	NATURAL GAS	182	MMBTU/HR	NO_x	LOW NOX BURNERS/FLUE GAS RECIRCULATION AND GOOD COMBUSTION PRACTICES.	0.04	LB/MMBTU	BACT-PSD
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	107-13C	MI	4931	221112	12/5/2016	EU AUX BOILER (AUXILIARY BOILER)	13.31	NATURAL GAS	83.5	MMBTU/HR	NO_x	LOW NOX BURNERS/INTERNAL FLUE GAS RECIRCULATION AND GOOD COMBUSTION PRACTICES.	0.05	LB/MMBTU	BACT-PSD

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MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	185-15A	MI	4922	486210	3/24/2017	FG AUX BOILERS (6 AUXILIARY BOILERS EU AUX BOIL 2A, EU AUX BOIL 3A, EU AUX BOIL 2B, EU AUX BOIL 3B, EU AUX BOIL 2C, EU AUX BOIL 3C)	13.31	NATURAL GAS	3	MMBTU/HR	NO_x	ULTRA-LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES.	20	PPM AT 3% O2	BACT-PSD
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	167-17 AND 168-17	MI	4911	221112	6/29/2018	EU AUX BOILER (NORTH PLANT): AUXILIARY BOILDER	13.31	NATURAL GAS	61.5	MMBTU/HR	NO_x	LOW NOX BURNERS/FLUE GAS RECIRCULATION AND GOOD COMBUSTION PRACTICES.	0.04	LB/MMBTU	BACT-PSD
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	167-17 AND 168-17	MI	4911	221112	6/29/2018	EU AUX BOILER (SOUTH PLANT): AUXILIARY BOILER	13.31	NATURAL GAS	61.5	MMBTU/HR	NO_x	LOW NOX BURNERS/FLUE GAS RECIRCULATION AND GOOD COMBUSTION PRACTICES.	0.04	LB/MMBTU	BACT-PSD
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	19-18	MI	4911	221112	7/16/2018	EU AUX BOILER: AUXILIARY BOILER	13.31	NATURAL GAS	99.9	MMBTU/HR	NO_x	LOW NOX BURNERS/FLUE GAS RECIRCULATION.	0.036	LB/MMBTU	BACT-PSD
MI-0440	MICHIGAN STATE UNIVERSITY	139-18	MI	4911	611310	5/22/2019	EU STM BOILER	11.31	NATURAL GAS	300	MMBTU/HR	NO_x	LOW-NOX BURNERS AND INTERNAL FLUE GAS RECIRCULATION (FGR)	0.04	LB/MMBTU	BACT-PSD
MI-0441	LBWL–ERICKSON STATION	74-18	MI	4911	221112	12/21/2018	EU AUX BOILER– NATURAL GAS FIRED AUXILIARY BOILER RATED AT = 99MMBTU/H	13.31	NATURAL GAS	99	MMBTU/HR	NO_x	LOW NOX BURNERS (LNB) OR FLUE GAS RECIRCULATION ALONG WITH GOOD COMBUSTION PRACTICES.	30	PPM	BACT-PSD
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	210-18	MI	4911	221112	8/21/2019	FG AUX BOILER	13.31	NATURAL GAS	80	MMBTU/HR	NO_x	GOOD COMBUSTION PRACTICES AND LOW NOX BURNERS.	0.036	LB/MMBTU	BACT-PSD
*MI-0445	INDECK NILES, LLC	75-16B	MI	4911	221112	11/26/2019	EU AUX BOILER	12.31	NATURAL GAS	182	MMBTU/HR	NO_x	LOW NOX BURNERS/FLUE GAS RECIRCULATION AND GOOD COMBUSTION PRACTICES.	0.04	LB/MMBTU	BACT-PSD
MI-0447	LBWL–ERICKSON STATION	74-18A	MI	4911	221112	1/7/2021	EU AUX BOILER-- NAT GAS FIRED AUXILIARY BOILER	13.31	NATURAL GAS	50	MMBTU/HR	NO_x	LOW NOX BURNERS (LNB) OR FLUE GAS RECIRCULATION (FGR) ALONG WITH GOOD COMBUSTION PRACTICES.	30	PPM	BACT-PSD
NJ-0079	WOODBRIDGE ENERGY CENTER	18940 - BOP110003	NJ	4911	221112	7/25/2012	COMMERCIAL/INSTITUTIONAL SIZE BOILERS LESS THAN 100 MMBTU/HR	13.31	NATURAL GAS	2,000	H/YR	NO_x	LOW NOX BURNERS	0.01	LB/MMBTU	LAER
NJ-0080	HESS NEWARK ENERGY CENTER	08857/BOP110001	NJ	4911	221112	11/1/2012	BOILER LESS THAN 100 MMBTU/HR	13.31	NATURAL GAS	51.9	MMCFT/YR	NO_x	LOW NOX BURNERS AND FLUE GAS RECIRCULATION	0.01	LB/MMBTU	LAER

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NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	18068/BOP150001	NJ	4911	221112	3/10/2016	AUXILIARY BOILER FIRING NATURAL GAS	13.31	NATURAL GAS	687	MMCFT/YR	NO_x	LOW NOX BURNERS AND FLUE GAS RECIRCULATION (FGR)	0.8	LB/H	LAER
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	19149/PCP150001	NJ	4911	221112	7/19/2016	AUXILIARY BOILER	13.31	NATURAL GAS	4,000	H/YR	NO_x	LOW NOX BURNERS AND FLUE GAS RECIRCULATION (FGR) AND USE OF NATURAL GAS A CLEAN BURNING FUEL	0.975	LB/H	LAER
NY-0103	CRICKET VALLEY ENERGY CENTER	3-1326-00275/00009	NY	4911	221112	2/3/2016	AUXILIARY BOILER	13.31	NATURAL GAS	60	MMBTU/HR	NO_x	FLUE GAS RECIRCULATION WITH LOW NOX BURNERS	0.0085	LB/MMBTU	LAER
NY-0104	CPV VALLEY ENERGY CENTER	3-335600136/00001	NY	4911	221112	8/1/2013	AUXILIARY BOILER	13.31	NATURAL GAS	0		NO_x	FLUE GAS RECIRCULATION WITH LOW NOX BURNERS.	0.045	LB/MMBTU	LAER
OH-0350	REPUBLIC STEEL	P0109191	OH	3312	331111	7/18/2012	STEAM BOILER	13.31	NATURAL GAS	65	MMBTU/HR	NO_x		0.07	LB/MMBTU	N/A
OH-0352	OREGON CLEAN ENERGY CENTER	P0110840	OH	4931	221112	6/18/2013	AUXILLARY BOILER	13.31	NATURAL GAS	99	MMBTU/HR	NO_x	LOW NOX BURNERS AND FLUE GAS RECIRCULATION	1.98	LB/H	BACT-PSD
OH-0360	CARROLL COUNTY ENERGY	P0113762	OH	4911	221112	11/5/2013	AUXILIARY BOILER (B001)	13.31	NATURAL GAS	99	MMBTU/HR	NO_x	LOW NOX BURNERS AND FLUE GAS RECIRCULATION	1.98	LB/H	BACT-PSD
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	P0117655	OH	4911	221112	8/25/2015	AUXILIARY BOILER (B001)	13.31	NATURAL GAS	34	MMBTU/HR	NO_x	FLUE GAS RECIRCULATION (FGR) AND LOW NOX BURNER	0.68	LB/H	BACT-PSD
OH-0367	SOUTH FIELD ENERGY LLC	P0119495	OH	4911	221112	9/23/2016	AUXILIARY BOILER (B001)	13.31	NATURAL GAS	99	MMBTU/HR	NO_x	FLUE GAS RECIRCULATION (FGR), LOW NOX BURNER, AND NATURAL GAS/ULTRA LOW SULFUR DIESEL	9.9	LB/H	BACT-PSD
OH-0368	PALLAS NITROGEN LLC	P0118959	OH	2873	325311	4/19/2017	PACKAGE BOILERS (2 IDENTICAL, B003 AND B004)	11.31	NATURAL GAS	265	MMBTU/HR	NO_x	LOW NOX BURNERS AND FLUE GAS RECIRCULATION (FGR)	3.3	LB/H	BACT-PSD
OH-0370	TRUMBULL ENERGY CENTER	P0122331	OH	4911	221112	9/7/2017	AUXILIARY BOILER (B001)	13.31	NATURAL GAS	37.8	MMBTU/HR	NO_x	FLUE GAS RECIRCULATION (FGR), LOW NOX BURNER	0.76	LB/H	BACT-PSD
OH-0372	OREGON ENERGY CENTER	P0121049	OH	4911	221112	9/27/2017	AUXILIARY BOILER (B001)	13.31	NATURAL GAS	37.8	MMBTU/HR	NO_x	LOW NOX BURNERS AND FLUE GAS RECIRCULATION	0.76	LB/H	BACT-PSD
OH-0374	GUERNSEY POWER STATION LLC	P0122594	OH	4911	221112	10/23/2017	AUXILIARY BOILER (B001)	12.31	NATURAL GAS	185	MMBTU/HR	NO_x	LOW-NOX BURNERS AND FLUE GAS RECIRCULATION	3.7	LB/H	BACT-PSD
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	P0122829	OH	4911	221112	11/7/2017	AUXILIARY BOILER (B001)	13.31	NATURAL GAS	26.8	MMBTU/HR	NO_x	FLUE GAS RECIRCULATION AND LOW NOX BURNER	0.29	LB/H	BACT-PSD
OH-0377	HARRISON POWER	P0122266	OH	4911	221112	4/19/2018	AUXILIARY BOILER (B001)	13.31	NATURAL GAS	44.55	MMBTU/HR	NO_x	GOOD COMBUSTION PRACTICES AND LOW NOX BURNER	1.56	LB/H	BACT-PSD

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OH-0377	HARRISON POWER	P0122266	OH	4911	221112	4/19/2018	AUXILIARY BOILER (B002)	13.31	NATURAL GAS	80	MMBTU/HR	NO_x	GOOD COMBUSTION PRACTICES AND LOW NOX BURNER	2.19	LB/H	BACT-PSD
OH-0379	PETMIN USA INCORPORATED	P0125024	OH	3312	331111	2/6/2019	STARTUP BOILER (B001)	13.31	NATURAL GAS	15.17	MMBTU/HR	NO_x	LOW-NOX BURNERS, GOOD COMBUSTION PRACTICES AND THE USE OF NATURAL GAS	0.634	LB/H	BACT-PSD
OK-0148	BUFFALO CREEK PROCESSING PLANT	2012-1026-C PSD	OK	1321	211112	9/12/2012	COMMERCIAL/INSTITUTIONAL BOILERS (100 MMBTUH)	13.31	NATURAL GAS	11.04	MMBTU/HR	NO_x	LOW-NOX BURNERS	0.045	LB/MMBTU	BACT-PSD
OK-0156	NORTHSTAR AGRI IND ENID	2013-0109-C PSD	OK	2076	311223	7/31/2013	REFINERY BOILER	13.31	NATURAL GAS	5	MMBTU/HR	NO_x	GOOD COMBUSTION	0.0075	LB/MMBTU	N/A
OR-0050	TROUTDALE ENERGY CENTER, LLC	26-0235	OR	4911	221112	3/5/2014	AUXILIARY BOILER	13.31	NATURAL GAS	39.8	MMBTU/HR	NO_x	UTILIZE LOW-NOX BURNERS AND FGR.	0.035	LB/MMBTU	BACT-PSD
PA-0291	HICKORY RUN ENERGY STATION	37-337A	PA	4911	221112	4/23/2013	AUXILIARY BOILER	13.31	NATURAL GAS	40	MMBTU/HR	NO_x		0.011	LB/MMBTU	OTHER CASE-BY-CASE
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNE E	06-05150A	PA	4931	221112	12/17/2013	AUXILIARY BOILER	13.31	NATURAL GAS	40	MMBTU/HR	NO_x		1.01	T/YR	OTHER CASE-BY-CASE
PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	67-05083D/F	PA	4911	221112	6/15/2015	AUXILARY BOILER	13.31	NATURAL GAS	62.04	MCF/HR	NO_x	GOOD COMBUSTION PRACTICES, ULTRA-LOW NOX BURNERS, FGR	0.0086	LB/MMBTU	LAER
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	35-00069A	PA	4911	221112	12/23/2015	AUXILLARY BOILER	13.31	NATURAL GAS	13.31	MMBTU/HR	NO_x	SCR AND ULTRA LOW NOX BURNERS, FIRED ONLY ON NATURAL GAS SUPPLIED BY A PUBLIC UTILITY.	0.006	LB/MMBTU	LAER
PA-0310	CPV FAIRVIEW ENERGY CENTER	11-00536A	PA	4911	221112	9/2/2016	AUXILARY BOILER	13.31	NATURAL GAS	92.4	MMBTU/HR	NO_x	ULTRA LOW NOX BURNERS, FGR, GOOD COMBUSTION PRACTICES	0.011	LB/MMBTU	LAER
PA-0311	MOXIE FREEDOM GENERATION PLANT	40-00129A	PA	4911	221112	9/1/2015	AUXILARY BOILER	13.31	NATURAL GAS	55.4	MMBTU/HR	NO_x		0.006	LB/MMBTU	LAER
*PA-0316	RENOVO ENERGY CENTER, LLC	18-00033A	PA	4911	221112	1/26/2018	AUXILIARY BOILER	13.31	NATURAL GAS	118,800	MMBTU/HR 12-MONTH PERIOD	NO_x	ULTRA-LOW NOX BURNERS AND FLUE GAS RE-CIRCULATION OPERATED IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATIONS AND GOOD OPERATING PRACTICES	0.011	LB	LAER
*PA-0319	RENAISSANCE ENERGY CENTER	30-00235A	PA	4911	221112	8/27/2018	NATURAL GAS FIRED AUXILIARY BOILER	13.31	NATURAL GAS	88	MMBTU/HR	NO_x	LO-NOX BURNERS, FLUE GAS RECIRCULATION, GOOD COMBUSTION PRACTICES, PROPER OPERATION AND MAINTAINANCE.	0.02	LB/MMBTU	LAER

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SC-0113	PYRAMAX CERAMICS, LLC	0160-0023	SC	3295	327992	2/8/2012	BOILERS	13.31	NATURAL GAS	5	MMBTU/HR	NO_x	GOOD DESIGN AND COMBUSTION PRACTICES, LOW NOX BURNERS, COMBUSTION OF NATURAL GAS/PROPANE.	0		BACT-PSD
SC-0149	KLAUSNER HOLDING USA, INC	1860-0128-CA	SC	2421	321113	1/3/2013	NATURAL GAS BOILER EU003	11.31	NATURAL GAS	46	MMBTU/HR	NO_x		0.036	LB/MMBTU	OTHER CASE-BY-CASE
SC-0149	KLAUSNER HOLDING USA, INC	1860-0128-CA	SC	2421	321113	1/3/2013	NATURAL GAS BOILER EU004	13.31	NATURAL GAS	46	MMBTU/HR	NO_x		0.036	LB/MMBTU	OTHER CASE-BY-CASE
SC-0149	KLAUSNER HOLDING USA, INC	1860-0128-CA	SC	2421	321113	1/3/2013	NATURAL GAS BOILER EU005	13.31	NATURAL GAS	46	MMBTU/HR	NO_x		0.036	LB/MMBTU	OTHER CASE-BY-CASE
SC-0149	KLAUSNER HOLDING USA, INC	1860-0128-CA	SC	2421	321113	1/3/2013	NATURAL GAS BOILER EU006	13.31	NATURAL GAS	46	MMBTU/HR	NO_x		0.036	LB/MMBTU	OTHER CASE-BY-CASE
TX-0656	GAS TO GASOLINE PLANT	PSDTX1340 AND 107764	TX	2911	325199	5/16/2014	BOILER	11.31	NATURAL GAS AND FUEL GAS	950	MMBTU/HR	NO_x	SCR	0.01	LB/MMBTU	BACT-PSD
TX-0713	TENASKA BROWNSVILLE GENERATING STATION	108411 PSDTX1350	TX	4911	221112	4/29/2014	BOILER	13.31	NATURAL GAS	90	MMBTU/HR	NO_x	ULTRA LOW-NOX BURNERS, LIMITED USE	9	PPMVD	BACT-PSD
TX-0714	S R BERTRON ELECTRIC GENERATING STATION	102731 PSDTX1294	TX	4911	221112	12/19/2014	BOILER	13.31	NATURAL GAS	80	MMBTU/HR	NO_x	LOW-NOX BURNERS	0.036	LB/MMBTU	BACT-PSD
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	117026, PSDTX1390, N194	TX	4911	221122	6/18/2015	COMMERCIAL/INSTITUTIONAL SIZE BOILERS (100 MMBTU) NATURAL GAS	13.31	NATURAL GAS	73.3	MMBTU/HR	NO_x		0.01	MMBTU/H	LAER
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOADTERMINAL (PBPTT)	118901, GHGPSDTX108 AND PSDTX1	TX	5171	424710	11/6/2015	COMMERCIAL/INSTITUTIONAL - SIZE BOILERS/FURNACES	13.31	NATURAL GAS	40	MMBTU/HR	NO_x	LOW NOX BURNERS	0.036	LB/MMBTU	BACT-PSD
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	118901, GHGPSDTX108 AND PSDTX1	TX	5171	424710	11/6/2015	COMMERCIAL/INSTITUTIONAL - SIZE BOILERS/FURNACES	13.31	NATURAL GAS	95.7	MMBTU/HR	NO_x	LOW NOX BURNERS AND FLUE GAS RECIRCULATION	0.011	LB/MMBTU	BACT-PSD
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	118901, GHGPSDTX108 AND PSDTX1	TX	5171	424710	11/6/2015	COMMERCIAL/INSTITUTIONAL - SIZE BOILERS/FURNACES	13.31	NATURAL GAS	13.2	MMBTU/HR	NO_x		0.1	LB/MMBTU	BACT-PSD
TX-0888	ORANGE POLYETHYLENE PLANT	155952 PSDTX1556 GHGPSDTX192	TX	2821	325211	4/23/2020	BOILERS	11.31	NATURAL GAS, ETHANE, FUEL, OR VENT GAS	250	MMBTU/HR	NO_x	SCR	0.015	LB/MMBTU	BACT-PSD

* Represents draft entries into the RBLC which may not be complete.

Table 2. NOx RBLC Data for Boilers

RBLCID	Facility Name	Permit No.	Facility State	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
VA-0321	BRUNSWICK COUNTY POWER STATION	52404	VA	4911	221112	3/12/2013	AUXILIARY BOILER	13.31	NATURAL GAS	66.7	MMBTU/HR	NO_x	DRY LOW NOX BURNER.	9	PPMVD	BACT-PSD
WI-0283	AFE, INC. LCM PLANT	17-JJW-207	WI	3679	334419	4/24/2018	B01-B12, BOILERS	13.31	NATURAL GAS	28	MMBTU/HR	NO_x	ULTRA-LOW NOX BURNERS, FLUE GAS RECIRCULATION AND GOOD COMBUSTION PRACTICES	0.0105	LB/MMBTU	BACT-PSD
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	18-JJW-017	WI	4911	221112	4/24/2018	B13-B24 & B25-B36 NATURAL GAS-FIRED BOILERS	13.31	NATURAL GAS	28	MMBTU/HR	NO_x	ULTRA-LOW NOX BURNERS, FLUE GAS RECIRCULATION, AND GOOD COMBUSTION PRACTICES.	0.0105	LB/MMBTU	BACT-PSD
WI-0300	NEMADJI TRAIL ENERGY CENTER	18-MMC-168	WI	4911	221121	9/1/2020	NATURAL GAS-FIRED AUXILIARY BOILER (B02)	13.31	NATURAL GAS	100	MMBTU/HR	NO_x	ULTRA-LOW NOX BURNERS, FLUE GAS RECIRCULATION, AND OPERATE AND MAINTAIN B02 ACCORDING TO THE MANUFACTURER'S RECOMMENDATIONS.	0.011	LB/MMBTU	BACT-PSD
WI-0306	WPL- RIVERSIDE ENERGY CENTER	19-POY-212	WI	4911	221112	2/28/2020	TEMPORARY BOILER (B98A)	13.31	NATURAL GAS	14.67	MMBTU/HR	NO_x	LOW NOX BURNERS, FLUE GAS RECIRCULATION, SHALL BE OPERATED FOR NO MORE THAN 500 HOURS, AND SHALL COMBUST ONLY PIPELINE QUALITY NATURAL GAS.	0.04	LB/MMBTU	BACT-PSD
*WV-0029	HARRISON COUNTY POWER PLANT	R14-0036	WV	4911	221112	3/27/2018	AUXILIARY BOILER	13.31	NATURAL GAS	77.8	MMBTU/HR	NO_x	LNB, FGR, GOOD COMBUSTION PRACTICES	0.86	LB/HR	BACT-PSD
*WV-0032	BROOKE COUNTY POWER PLANT	R14-0035	WV	4911	221112	9/18/2018	AUXILIARY BOILER	13.31	NATURAL GAS / ETHANE	111.9	MMBTU/HR	NO_x	LNB, GOOD COMBUSTION PRACTICES	1.23	LB/HR	BACT-PSD
WY-0075	CHEYENNE PRAIRIE GENERATING STATION	MD-16173	WY	4911	221122	7/16/2014	AUXILIARY BOILER	13.31	NATURAL GAS	25.06	MMBTU/HR	NO_x	ULTRA LOW NOX BURNERS AND FLUE GAS RECIRCULATION	0.0175	LB/MMBTU	BACT-PSD

* Represents draft entries into the RBLC which may not be complete.

APPENDIX B: EMISSION UNITS SUBJECT TO RACT

Table B-1. List of EU's Subject to RACT

EU	Description	NO_x (tpy)	EU	Description	NO_x (tpy)
MG13	Cleaver Brooks Boiler, M/N: CBLE700-800-200, S/N: OL097510	6.95	LX025	Caterpillar Emergency Generator, M/N: 3512C, S/N: EGB00203	7.5
MG14	Cleaver Brooks Boiler, M/N: CBLE700-800-200, S/N: OL096895	6.95	EX007	Caterpillar Emergency Generator, M/N: 3512, S/N: 24Z02774	9.55
MG17	Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02910	15.12	EX008	Caterpillar Emergency Generator, M/N: 3512, S/N: 24Z02784	9.55
MG18	Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02931	15.12	EX009	Caterpillar Emergency Generator, M/N: 3512, S/N: 24Z02770	9.55
MG19	Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02927	15.12	EX010	Caterpillar Emergency Generator, M/N: 3512, S/N: 24Z02753	9.55
MG20	Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02913	15.12	BE80	Caterpillar Emergency Generator, M/N: 3416, S/N: 25Z05330	15.12
MG21	Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02929	15.12	BE81	Caterpillar Emergency Generator, M/N: 3416, S/N: 25Z05335	15.12
MG22	Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02932	15.12	BE82	Caterpillar Emergency Generator, M/N: 3416, S/N: 25Z05333	15.12
MG23	Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02916	15.12	BE83	Caterpillar Emergency Generator, M/N: 3416, S/N: 25Z05332	15.12
MC019	Caterpillar Emergency Generator, M/N: 3512, S/N: 6WN00081	13.03	BE85	Caterpillar Emergency Generator, M/N: 3416, S/N: 25Z05339	15.12
MC020	Caterpillar Emergency Generator, M/N: 3512, S/N: 6WN00082	13.03	BE86	Caterpillar Emergency Generator, M/N: 3416, S/N: 25Z05338	15.12
TBA15	Caterpillar Diesel Emergency Generator, M/N: 3412CTA, S/N: 1EZ07104	7.08	BE87	Caterpillar Emergency Generator, M/N: 3416, S/N: 25Z05340	15.12
MB061	Caterpillar Emergency Generator, M/N: 3516 DITA, S/N: 25Z06027	13.01	BE88	Caterpillar Emergency Generator, M/N: 3416, S/N: 1LZ00545	15.12

EU	Description	NO_x (tpy)	EU	Description	NO_x (tpy)
MB062	Caterpillar Emergency Generator, M/N: 3516 DITA, S/N: 25Z02994	13.01	CC009	Caterpillar Emergency Generator, M/N: 3416, S/N: 1LZ00546	15.12
MB063	Caterpillar Emergency Generator, M/N: 3516 DITA, S/N: 25Z03002	13.01	CC010	Caterpillar Diesel Emergency Generator, M/N: 3516C, S/N: SBK00196	9.35
MB066	Caterpillar Emergency Generator, M/N: 3516 DITA, S/N: 3NS00234	15.11	CC011	Caterpillar Diesel Emergency Generator, M/N: 3516C, S/N: SBK00197	9.35
MB067	Cummins Emergency Generator, M/N: KTA50-G9, S/N: 33146939	13.32	CC012	Caterpillar Diesel Emergency Generator, M/N: 3516C, S/N: SBK00198	9.35
MB093	Caterpillar Emergency Generator, M/N: 3512, S/N: 1GZ01339	13.03	CC013	Caterpillar Diesel Emergency Generator, M/N: 3516C, S/N: SBJ00378	10.47
LX009	Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z03005	13.01	CC014	Caterpillar Diesel Emergency Generator, M/N: 3516C, S/N: SBJ00379	10.47
LX010	Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02998	13.01	CC015	Caterpillar Diesel Emergency Generator, M/N: 3516C, S/N: SBJ00380	10.47
LX011	Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02999	13.01	TM01	Caterpillar Diesel Emergency Generator, M/N: 3516C, S/N: SBJ00382	10.47
LX024	Caterpillar Emergency Generator, M/N: 3512C, S/N: EGB00199	7.5	TBB15	Caterpillar Emergency Generator, M/N: 3516DITA, S/N: DD501118	10.83
NY27	Caterpillar Emergency Generator, M/N: 3512TA, S/N: 24Z06937	10.91	TBB15	Caterpillar Emergency Generator, M/N: 3516 BTA, S/N: GZR00237	15.12
NY28	Caterpillar Emergency Generator, M/N: 3512TA, S/N: 24Z06932	10.91	NY29	Caterpillar Emergency Generator, M/N: 3512TA, S/N: 24Z06931	10.91

Appendix 6

CAL/NEV Pipeline RACT Analysis

KINDER MORGAN
CALNEV PIPE LINE LLC

October 3, 2022

Mr. Ted Lendis
Permitting Manager
Clark County DAQ
4701 West Russell Road
Suite 200
Las Vegas NV 89118-2231

Subject: RACT Requirements Review
Calnev Pipe Line, LLC – Las Vegas Terminal, Part 70 Permit Number 13
5049 North Sloan Lane, Las Vegas, NV 89115

Dear Mr. Lendis:

Please find the enclosed the RACT requirements review for emissions at the Calnev Pipe Line, LLC Las Vegas Terminal. If you have any questions please contact Nina McAfee at (713) 420-5610 or Cinnamon Smith at (281) 731-8854.

Sincerely,

William Toepfer
Director of Operations
For Calnev Pipe Line, LLC

Enclosures:

1. RACT Requirements Review

Calnev Pipe Line, LLC
Las Vegas Terminal

5049 North Sloan Lane
Las Vegas, NV 89115

Part 70 Permit No. 13

October 2022

Prepared by:

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RACT Requirement Report

RACT Requirement Report

Prepared for:

Calnev Pipe Line, LLC
Las Vegas Terminal
5049 North Sloan Lane
Las Vegas, NV 89115

October 2022

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RACT Requirement Report

1.0 INTRODUCTION

Kinder Morgan's subsidiary Calnev Pipe Line, LLC (Calnev) owns and operates a petroleum products distribution terminal facility located at 5049 North Sloan Lane in Las Vegas, Nevada. The Las Vegas Terminal's (LVT's) operations include receiving petroleum fuel products via pipeline or truck and transferring gasoline, diesel, and biodiesel from storage tanks into trucks via loading racks.

The Clark County Department of Air Quality (DAQ) recently contacted Kinder Morgan regarding implementation of the State Implementation Plan (SIP) to comply with the 2015 ozone standard. As part of this process, the Clark County DAQ has asked Kinder Morgan to conduct a Reasonably Achievable Control Technology (RACT) analysis for volatile organic compound (VOC) emissions and supply facility-specific information to determine the appropriate RACT controls for the terminal. The information on facility operations and emissions contained herein is primarily based on the LVT's 2021 Title V Renewal, which was submitted in 2021.

2.0 GENERAL INFORMATION REQUEST

2.1 Background

Clark County DAQ has requested the following general information related to facility operations:

- Confirmation of major source potential to emit (PTE);
- List of emissions units potentially subject to RACT;
- Rated size or maximum capacity of each emissions unit;
- Description of emissions patterns over the year; and
- Information on emissions related to training, certification, or testing requirements.

2.2 Confirmation of Major Source PTE

The LVT is a bulk petroleum distribution terminal; with a standard industrial classification (SIC) code of 4226 and a North American Industry Classification System (NAICS) code of 424710. The terminal receives petroleum fuel products via pipeline or truck and transfers gasoline, diesel, and biodiesel from storage tanks into trucks via loading racks. Denatured ethanol stored and distributed at the LVT is received via railcar; the terminal also has the capability to unload ethanol via tank trucks.

Based on the PTE results, the emission calculations included in Appendix A demonstrate that the LVT is a Major Source for VOC emissions and a Minor Source of nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter less than 10 microns in size (PM_{10}), particulate matter less than 2.5 microns in size ($PM_{2.5}$), and hazardous air pollutants (HAPs). The emissions of NO_x, CO, SO_2, PM_{10}, and $PM_{2.5}$ are each below 10 tons per year. Total HAP emissions are below 25 tons per year, and emissions of any single HAP are below 10 tons per year.

Therefore, only the provisions of VOC RACT apply to the LVT; a review of NO_x RACT is not applicable. Based on guidance given by DAQ, Phase 1 of the County's review will focus on emissions units with a PTE of greater than 5 tons per year (tpy).

2.3 Emission Sources Evaluated for VOC RACT

- Fuel storage tanks (61.3 tpy), consisting of:
  - Three vertical fixed roof tanks;
  - 21 internal floating roof tanks;
  - 12 external floating roof tanks; and
  - Three domed external floating roof tanks;
- One vapor recovery unit (14.5 tpy);
- Loading Racks (65.7 tpy);
- Remediation system (37.7 tpy); and
- Fugitive components such as valves, flanges, fittings, and pump seals (6.6 tpy).

2.4 Emissions Sources Not Evaluated for VOC RACT

Sources with a VOC PTE of less than 5 tons per year are excluded from this analysis.

These include:

- Six sumps (2.1 tpy);
- Parts washer (1.17 tpy);
- 20 fuel additive storage tanks (0.12 tpy);
- Two provers (0.16 tpy);
- Ethanol unloading system (0.18 tpy);
- Biofuel unloading system, including a portable prover (0.04 tpy);
- Water treatment system that includes two underground surge storage tanks, an oil-water separator, and an evaporation pond (0.1 tpy);
- Cooling tower that serves the vapor recovery unit (0.0 tpy);
- One auxiliary flare (0.0 tpy);
- Two internal combustion engines; one engine serves the air compressor and the other serves the emergency fire pump (0.13 tpy); and
- One 90,000-gallon horizontal pressurized tank storing butane (0.0 tpy).

2.5 Rated Size or Maximum Capacity of each Emissions Unit

A complete listing of equipment capacities for all equipment with a VOC PTE of great than 5 tons per year is included in the following sections. Other than Tanks 501 and 522, both of which are permitted to only store denatured ethanol, all the floating-roof aboveground storage tanks are designed and permitted to store multiple liquids. Tanks that are currently in gasoline service may occasionally be used to store other, lower vapor pressure petroleum products depending on market needs.

2.6 Description of Emissions Patterns Over the Year

The operating schedule for the facility is 24 hours per day, 7 days per week, and 52 weeks per year. At various times throughout the year, gasoline with different vapor pressure is loaded. The emissions from the multi-product tanks and loading racks were calculated using gasoline with an average Reid Vapor Pressure (RVP) of 11. An RVP of 11 is the annual average vapor pressure of gasoline stored and loaded at the LVT. There is not expected to be a significant difference in VOC emissions over the course of the year.

2.7 Information on Emissions Related to Training, Certification, or Testing Requirements

A fixed-volume meter-prover (prover) is operated at the LVT to verify the calibration of flow meters used for measurement of the liquid delivered to the LVT via pipelines. A single prover is used on the multiple products pipelines entering the LVT. Verification of pipeline flow rate is accomplished by tracking the time required for an internal float to be conveyed through the prover loop. During normal operation, petroleum products from the pipeline are routed through the prover and then returned to the pipeline. There are no emissions to the atmosphere during normal operation. When it is necessary to empty the prover loop and prepare it for service, liquid contained in the prover is drained into its subsurface sump. The sump has a vent open to atmosphere. The liquid product in the sump is periodically pumped back to the dedicated tank. There are emissions associated with draining the prover and venting it during the refilling process, summarized in Appendix A. The prover is taken out of service up to 12 times per year.

3.0 RACT REQUIREMENTS

3.1 RACT for Storage Tanks

VOC emissions at bulk petroleum product terminals occur when fuel products are transferred through storage tanks (“working losses”), as well as losses associated with daily temperature cycles while the liquid is stored (“standing losses”). Four types of aboveground storage tanks are utilized at the LVT: (1) Internal Floating Roof (IFR) tanks, (2) External Floating Roof (EFR) tanks, (3) Domed External Floating Roof (DEFR) tanks, and (4) Fixed Roof tanks (FRT), including both vertical and horizontal tanks.

Table 3-1: Fuel Storage Tank Information and PTE at Las Vegas Terminal

Emission Unit	Tank No.	Tank Type	Capacity (bbl)	Max Throughput (bbl)	Potential to Emit (tpy)	Rim Seal(s)	Permitted Product
A01	530	EFR	11,200	28,560,000	1.33	Primary and Secondary	Multi fuel
A02	531	EFR	12,890	32,460,000	1.41	Primary and Secondary	Multi fuel
A03	532	EFR	8,080	20,340,000	1.14	Primary and Secondary	Multi fuel
A04	533	EFR	11,330	28,560,000	1.33	Primary and Secondary	Multi fuel
A05	534	EFR	8,080	20,340,000	1.14	Primary and Secondary	Multi fuel
A06	535	EFR	8,080	20,340,000	1.14	Primary and Secondary	Multi fuel
A07	536	EFR	17,550	44,220,000	1.64	Primary and Secondary	Multi fuel
A08	537	EFR	22,250	90,000,000	1.88	Primary and Secondary	Multi fuel
A09	538	EFR	11,330	28,560,000	2.76	Primary and Secondary	Multi fuel
A10	539	EFR	11,330	50,000,000	1.38	Primary and Secondary	Multi fuel
A11	540	IFR	16,320	137,000,000	1.90	Primary and Secondary	Multi fuel
A12	541	DEFR	25,100	864,000,000	1.86	Primary and Secondary	Multi fuel
A13	524	IFR	18,000	50,760,000	0.75	Primary and Secondary	Multi fuel
A14	542	IFR	45,000	118,500,000	0.17	Primary	Diesel/Biodiesel
A15	543	IFR	35,000	114,660,000	0.18	Primary	Diesel/Biodiesel
A16	545	IFR	37,000	88,200,000	2.14	Primary and Secondary	Multi fuel
A17	546	IFR	40,000	100,800,000	2.94	Primary and Secondary	Multi fuel
A18	522	IFR	4,000	9,000,000	0.28	Primary and Secondary	Denatured Ethanol
A19	525	FRT	50,000	350,000,000	1.84	N/A	Diesel/Biodiesel
A20	526	FRT	50,000	220,500,000	1.46	N/A	Diesel/Biodiesel
A21	547	IFR	50,000	100,800,000	2.58	Primary and Secondary	Multi fuel
A22	512	FRT	50,000	126,000,000	1.77	N/A	Jet Fuel, Diesel/Biodiesel
A23	510	EFR	40,000	100,800,000	0.18	Primary	Jet Fuel, Diesel/Biodiesel
A24	511	EFR	40,000	100,800,000	0.18	Primary	Jet Fuel, Diesel/Biodiesel
A27	501	IFR	4,000	9,540,000	0.32	Primary and Secondary	Denatured Ethanol
A28	523	IFR	10,000	23,580,000	1.53	Primary and Secondary	Multi fuel

Emission Unit	Tank No.	Tank Type	Capacity (bbl)	Max Throughput (bbl)	Potential to Emit (tpy)	Rim Seal(s)	Permitted Product
A29	544	IFR	11,000	27,720,000	1.72	Primary and Secondary	Multi fuel
A45	548	DEFR	12,890	32,460,000	2.00	Primary and Secondary	Multi fuel
A46	549	DEFR	12,890	32,460,000	1.04	Primary and Secondary	Multi fuel
A47	550	IFR	20,000	70,000,000	1.81	Primary and Secondary	Multi fuel
A48	551	IFR	10,100	50,400,000	1.75	Primary and Secondary	Multi fuel
A56	513	IFR	50,000	189,000,000	0.49	Primary and Secondary	Jet Fuel, Diesel/Biodiesel
A57	514	IFR	50,000	189,000,000	0.49	Primary and Secondary	Jet Fuel, Diesel/Biodiesel
A58	553	IFR	80,000	302,400,000	4.29	Primary and Secondary	Multi fuel
A59	554	IFR	80,000	604,800,000	4.98	Primary and Secondary	Multi fuel
A60	555	IFR	80,000	604,800,000	3.41	Primary and Secondary	Multi fuel
A61	552	IFR	40,000	126,000,000	2.26	Primary and Secondary	Multi fuel
B04	500	IFR	3,000	7,560,000	0.55	Primary and Secondary	Multi fuel
B05	521	IFR	5,000	12,720,000	1.24	Primary and Secondary	Multi fuel
D01	DG	FRT	5.9	595	0.01	N/A	Diesel/Biodiesel

As shown in Table 3-1, no individual storage tank at the LVT has a PTE of greater than 5 tons per year VOC; the following discussion details how these tanks employ stringent control technologies to comply with storage tank standards, as specified in the facility's Title V Permit.

3.1.1 Internal Floating Roof Tanks

IFR tanks offer better control of evaporative emissions than fixed roof tanks. The floating roof structure, usually of a pontoon or floating pan type, essentially eliminates the vapor headspace above the liquid surface. On most IFRs, primary and secondary seals of various types are installed along the edge of the floating roof to control evaporation through the gap between the floating roof structure and inner tank wall.

IFR storage tanks are not routinely emptied of product. The tanks are operated to maintain a heel of product between the roof and the floor. Since the floating roof remains suspended on the liquid contents, a vapor space does not form in the heel space. However, vapors may escape in small amounts as fugitive emissions through rim seals, deck fittings, or deck seals. Emissions can also occur while the product is withdrawn from an IFR and the floating roof is lowered. The portion of the interior tank wall that used to be covered by product is exposed to the headspace of the IFR tank.

IFR storage tanks are typically considered Best Available Control Technology (BACT) and therefore meet the requirements of RACT.

3.1.2 External Floating Roof Tanks, With and Without Domes

EFR tanks also offer better control of evaporative emissions than fixed roof tanks but are used for less volatile products than those in IFR tanks due to their greater exposure to the atmosphere and wind and weather conditions. The floating roof is usually heavier than a floating roof in an IFR tank.

A DEFR is an EFR tank where a dome was subsequently built over the roof, supported by the tank shell. It is different from an IFR tank only in that the dome was not built contemporaneously to the rest of the tank, and the roof fittings and rim seals are those of an EFR tank.

EFR and DEFR storage tanks are considered to meet BACT and therefore meet the requirements of RACT.

3.1.3 Fixed Roof Tanks

FRTs do not have an internal floating roof or pan. This allows vapors to evaporate from the liquid surface and accumulate in the headspace in response to daily temperature cycles that cause daily cycles in differential pressure between the tank and surroundings, representing breathing losses. During refilling, hydrocarbon vapor in the headspace is displaced by the incoming liquid and vented to the atmosphere, resulting in working losses.

At the LVT, the three fixed roof tanks in operation are used for low-volatility products, such as diesel, biodiesel, and jet fuel. Each tank has a PTE of less than 5 tons per year. As such, these sources have not been evaluated for RACT.

3.2 RACT for Loading Racks and Vapor Recovery Units

The LVT dispenses petroleum fuel products at loading racks, numbered 1 through 15, with a total permitted throughput of 35,379,927 barrels per year. Gasoline and diesel from storage tanks are loaded into trucks at the loading racks. Biodiesel, ethanol, and additives are blended during loading of petroleum products. VOC emissions from loading racks occur as organic vapors in empty tanker trucks that are displaced to the atmosphere by the liquid being loaded into the vessel. The vapors from the loading racks are controlled by the John Zink Vapor Recovery Unit (VRU), with the flare as a backup, to ensure that emissions to the atmosphere do not exceed 0.02 pounds per 1,000 gallons (2.4 milligrams per liter) of gasoline loaded. Each lane has vapor recovery hoses, such that hydrocarbon vapor contained in the tanker truck is displaced through a connection that vents the top of the truck tank. The captured vapor from the loading racks is routed to a vapor collection/processing system, which undergoes periodic source testing to confirm compliance with emission limits. Control efficiency for each of the vapor control/processing systems at the LVT is sufficient to continuously meet the limit specified in DAQ regulations. This system is considered to meet BACT and therefore meet the requirements of RACT.

Table 3-2: Loading Rack Emissions at Las Vegas Terminal

Product	Throughput (gal/yr)	Uncontrolled Emission Factor for Bulk Loading (lb/1,000 gal)	Vapor Generated (lbs)	Truck Loading Vapor Capture Efficiency (%)	Fugitive VOC Emissions (lbs/yr)	Fugitive VOC Emissions (ton/yr)
Gasoline	977,278,302	10.13	9,903,493	98.70%	128,745.40	64.37
Diesel/Biodiesel	366,790,872	0.03	10,151	98.70%	131.96	0.07
Jet Fuel	81,545,856	0.03	2,758	98.70%	35.86	0.02
Ethanol	51,307,116	2.82	144,804	98.70%	1,882.46	0.94
Transmix	7,174,440	6.46	46,340	98.70%	602.42	0.30
Additive	1,680,000	0.44	733	98.70%	9.53	0.0048

3.2.1 Emissions from VOC Control Devices

The John Zink VRU is the primary control device for the loading rack emissions. It is a high-efficiency adsorption-absorption hydrocarbon VRU. Captured hydrocarbon vapors from the loading racks are allowed to accumulate in a vapor holding tank. The vapor holding tank collects vapors until a pre-set level limit is reached. Level controls on the holding tank modulate the delivery of vapors to the downstream control device. The holding tank, because of its sealed design, does not emit air pollutants. Emissions from the VRU are shown in Table 3-3.

Table 3-3: Vapor Recovery Unit Emissions at Las Vegas Terminal

Product	Vapors to Control Units	Controlled VOC Emissions (ton/yr)
Gasoline	9,774,747.24	14.17
Diesel/Biodiesel	10,018.62	0.015
Jet Fuel	2,722.33	0.0039

Product	Vapors to Control Units	Controlled VOC Emissions (ton/yr)
Ethanol	142,922.03	0.207
Transmix	45,737.74	0.066
Additive	723.38	0.0010

There is also an auxiliary flare from Flare Industries (now part of Aereon), which is available for the control of loading rack vapors whenever the John Zink VRU is unavailable and/or inoperable. The combustion of hydrocarbons in the auxiliary flare also generates emissions of criteria pollutants, including CO, NO_x, and with minimal amounts of SO_x and PM_{10}. In addition, certain HAPs present in the vapors collected from the loading racks are also emitted from the auxiliary flare. Emissions from the auxiliary flare are shown in Table 3-4.

Table 3-4: Auxiliary Flare Emissions at Las Vegas Terminal

Pollutant	Vapors to Flare	Emission Factor	Emissions (lbs/yr)	Emissions (ton/yr)
NO_x	498,843.57	0.068 lb/MMBtu	637.38	0.32
CO		0.31 lb/MMBtu	2905.71	1.45
SO_x		0.0006 lb/lb	296.31	0.15
PM		0.0077 lb/MMBtu	71.71	0.04

These control technologies are considered BACT and therefore meet the requirements of RACT.

3.3 RACT for Fugitive Components

Fugitive hydrocarbon emissions may occur from imperfect fittings when liquid petroleum products are contained in the various pipelines and components throughout the terminal. Hydrocarbon vapors can be released from various piping components, such as valves, flanges, pump seals, sampling ports, and other fittings. The emission rate is based on default factors dependent on the type of component or fitting, the number of each type of component, and the category of fluid service (gas, light liquid, or heavy liquid). PTE is quantified based on the facility-wide component counts for the facility and is summarized in Table 3-5.

Table 3-5: Fugitive Emission Sources Las Vegas Terminal

Fitting Type	Number of Fittings	Factor (lbs/unit-hr)	VOC Emissions (lbs/yr)	VOC Emissions (ton/yr)
Valves (Gas Service)	2,376	2.87E-05	597.35	0.30
Valves (Light Liquid Service)	1,693	9.48E-05	1405.95	0.70
Valves (Heavy Liquid Service)	1,598	9.48E-05	1327.06	0.66
Fittings (Gas)	6,455	9.26E-05	5236.14	2.62
Fittings (Light Liquid)	4,311	1.76E-05	664.65	0.33
Fittings (Heavy Liquid)	4,620	1.76E-05	712.29	0.36
Pump Seals (Gas)	56	1.43E-04	70.15	0.04
Pump Seals (Light Liquid)	29	1.19E-03	302.31	0.15
Pump Seals (Heavy Liquid)	27	1.19E-03	281.46	0.14

Fitting Type	Number of Fittings	Factor (lbs/unit-hr)	VOC Emissions (lbs/yr)	VOC Emissions (ton/yr)
Relief Devices (Light Liquid)	12	2.87E-04	30.17	0.02
Relief Devices (Heavy Liquid)	24	2.87E-04	60.34	0.03
Relief Devices (Gas)	35	2.87E-04	87.99	0.04
Other (Gas)	434	2.65E-04	1007.49	0.50
Other (Light Liquid)	239	2.87E-04	600.87	0.30
Other (Heavy Liquid)	321	2.87E-04	807.03	0.40
Total			**13,191.26**	**6.60**

As specified in the facility's Title V permit, the facility inspects fugitive components for leaks on a consistent basis and repairs any leaks in the system. These leak monitoring protocols are considered to meet the requirements of RACT.

3.4 RACT for Remediation Systems

The LVT has a permit to operate a soil vapor extraction (SVE) combustion system to control emissions from historical soil contamination. This system can process a maximum of 6,000 standard cubic feet per minute (scfm) and has a destruction efficiency of 98.5%.

A fluidized bed reactor (FBR) system, using carbon beds for VOC control of greater than 95%, was permitted in 2014 to allow for an alternative to the SVE for this remediation system. This was due to high combined concentrations of VOC and methane in the remediation system vapors. Despite not typically using the combustion system, Calnev wishes to retain the allowable emission limits (and therefore PTE) associated with the SVE in the event that remediation conditions may once again favor combustion. VOC emissions from the vapor extraction system were calculated using the maximum vapor flow rate, maximum VOC inlet concentration, and 98.5% destruction efficiency for a thermal oxidizer. As shown in the April 2014 and September 2015 notifications, emissions from the FBR system are significantly lower than the allowable VOC limit for the combustion system.

Table 3-6: PTE of Vapor Extraction System at the Las Vegas Terminal

Pollutant	Emissions from Fuel Combustion (ton/yr)	Controlled Remediation Emissions (ton/yr)	Total Emissions (ton/yr)
NO_x	1.26	–	1.26
VOC	0.10	37.57	37.67
CO	0.73	–	0.73
SO_x	0.002	–	0.0017
PM	0.07	–	0.07

This system exists to control emissions from historical contamination. The control systems, either combustion or carbon adsorption, are both considered to meet BACT and therefore meet the requirements of RACT.

4.0 CONCLUSION

LVT has determined that all sources having a PTE of greater than 5 tons per year to already meet RACT-levels of VOC emissions control. Therefore, a detailed evaluation of cost effectiveness for additional controls or effectiveness is not necessary. The facility has sufficient permit conditions to ensure compliance with all emissions limits and monitoring requirements.

APPENDIX A – EMISSION CALCULATIONS

Equipment	Emission Unit ID	VOC	CO	NOx	SOx	PM	Total HAPs
Petroleum Product Storage Tanks	Multiple	61.32					0.00
Additive and Insignificant Storage Tanks	Multiple	0.12					0.01
Loading Racks - Fugitive Emissions	B01	65.70					3.40
Vapor Recovery Unit	B02	14.47					0.75
Flare	B10		1.45	0.32	0.15	0.04	
Ethanol Offloading	H09	0.18					4.63E-04
B-100 Biofuel Offloading and B-100 Prover	B01A	0.04					
Component Fugitives	B06	6.60					0.35
Provers	P01 & P02	0.16					0.01
Internal Combustion Engines	D02 & B11	0.13	0.35	1.61	0.11	0.11	4.39E-04
Haul Roads	E01					6.61	
Service Roads	H01					0.52	
Cooling Tower	H05					0.01	
Parts Washer	H13	1.17					
Sumps	H02, H03, H04, H06, H07, H08	2.07					0.11
Contact Water Treatment System	F01, F04, F05, F06	0.10					0.05
Remediation - Soil and Groundwater Vapor Extraction System	SR04	37.67	0.73	1.26	1.74E-03	0.07	
Remediation - OWS and OST	H11 & H12	0.79					0.04
	Total Emissions	**190.50**	**2.53**	**3.19**	**0.26**	**7.36**	**4.71**

Appendix 7

NV Energy RACT Analysis
(Clark Generating Station/Sun Peak Generating Station)

RECEIVED CC DAQ
2022 OCT 3 PM1:59

October 3, 2022

Mr. Ted Lendis
Permitting Manager
Clark County Department of Environmental and Sustainability, Division of Air Quality
4701 W. Russel Road, Suite 200
Las Vegas, Nevada 89118

RE: RACT Analyses Submittal
Clark Generating Station (Source: 7) & Sun Peak Generating Station (Source: 423)

Dear Mr. Lendis:

NV Energy (NVE) hereby submits the RACT evaluations for its Clark Generating Station (Source 7) and Sun Peak Generating Station (Source 423) as requested by DAQ via email correspondence dated August 3, 2022. The report and its attachments detail the RACT evaluation for both facilities, comprising of a NOx RACT analysis for the Sun Peak Generating Station as well as NOx & VOC RACT analyses for the Clark Generating Station, as clarified in subsequent correspondence.

NVE anticipates further communication from DAQ on this topic in the near future. If you require additional information or have any questions, please contact Sean Spitzer at (702) 402-5132, or via email at sean.spitzer@nvenergy.com.

I certify that, based on the information and belief formed after reasonable inquiry, the statements and information in this document are true, accurate, and complete.

Sincerely,

Mathew Johns
Vice President, Environmental Services and Land Management
NV Energy
Alternate Responsible Official

Reasonably Available Control Technology (RACT) Review – NOx and VOC Emissions

Clark and Sun Peak Generating Stations

Prepared for:

NV Energy
6226 W Sahara Ave
Las Vegas, NV 89146

Prepared by:

AECOM Technical Services, Inc.
250 Apollo Drive
Chelmsford, MA 01824

October 2022

1.0 Overview

On August 3, 2018 the Environmental Protection Agency (EPA) classified the Las Vegas Valley as a marginal non-attainment area for the 2015 National Ambient Air Quality Standard (NAAQS) for ozone. In a Federal Register notice published on July 22, 2022 the EPA proposed to find that this area had failed to attain the ozone NAAQS by the originally-designated attainment date (August 3, 2021). Accordingly, the agency proposed to reclassify the area to a moderate non-attainment area for this pollutant.

The proposed reclassification triggers certain statutory requirements for the Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ), which is the air regulatory agency responsible for ensuring that the Las Vegas Valley complies with the NAAQS. In particular, these requirements include preparation and submittal to the EPA of State Implementation Plan (SIP) revisions that include provisions to address the adoption of Reasonably Available Control Technology (RACT) for each major source of nitrogen oxide (NOx) or volatile organic compounds (VOC) emissions within the non-attainment area (i.e., sources that emit 100 tons/yr (tpy) or more of NOx or VOC). Based on the facilities potential to emit, the DAQ has determined that NV Energy's Edward W. Clark Generating Station (CGS) and Sun Peak Generating Station (SPGS) meet this 100 tpy emissions threshold and are thus subject to the requirement to evaluate RACT.

The DAQ is using a phased approach towards collecting information to inform its SIP revision that initially exempts any emission units at major sources that have potential emission rates that are less than or equal to 5 tpy from needing RACT consideration.

The SPGS is a major source of NOx emissions but is not a major source for VOC emissions. As described further below, the emission units at the SPGS whose PTE exceeds the 5 tpy RACT consideration threshold consist of three natural gas-fired General Electric Frame 7EA combustion turbines that operate in simple cycle mode. Accordingly, these three units (Units 3 – 5) are subject to RACT for NOx only. Furthermore, although these units are permitted to fire diesel fuel, the NOx RACT analysis for these units only contemplates their natural gas-fired operation, as diesel fuel was not used in any of the units during the baseline years and is not expected to be used in the future.

The CGS is a major source of both NOx and VOC emissions, and the emission units at the CGS with potential emissions above the DAQ's 5 tpy RACT threshold consist of seventeen natural gas-fired combustion turbine-based generating units. Four of these units (Units 5 – 8) are Westinghouse Model 501B6 combustion turbines operating in combined cycle mode that were installed in the 1980's, while one unit (Unit 4) is a General Electric Frame 7B (MS-7000) combustion turbine operating in simple cycle mode that was installed in 1973. The remaining emission units (Units 11 – 22) consist of twelve pairs of Pratt and Whitney FT8 combustion turbines installed in 2008 that operate in simple cycle mode. Thus, all seventeen combustion turbines at the CGS are subject to RACT for NOx and VOC emissions.

EPA has defined RACT[1] as "… the lowest emission limitation a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." RACT can be the use of add-on controls, process modifications, or any other means by which to reduce NOx and/or VOC emissions. RACT may also be a numerical emission limit or specified emission reduction percent, or a commitment to a set of enforceable process modifications.

[1] 44 Federal Register 53672, September 17, 1979

The DAQ has requested that RACT be assessed on a case-by-case basis, including identification of potential additional emission control options for each unit and an evaluation of the feasibility of installing such options considering any specific technical or economic feasibility considerations for each particular unit subject to evaluation.

2.0 RACT Assessment Methodology

A five-step approach to conducting this RACT assessment has been utilized. The steps, which are similar to the steps that are followed when conducting a top-down Best Available Control Technology (BACT) assessment, are:

- Identification of available control options
- Elimination of technically infeasible alternatives,
- Determination of the cost effectiveness of each remaining option,
- Evaluating the benefits and disbenefits associated with each option, and
- Identification of RACT

The following sections describe the five factors that make up the RACT assessment approach that was utilized in this analysis for the existing emission units at the two NV Energy power plants.

Step 1 – Identification of Available Options

The first step consists of defining the spectrum of process and/or add-on control alternatives potentially applicable to the subject emissions unit.

A control technology must be "available" to be considered in a RACT determination. This means that the technology has progressed beyond the conceptual stage and pilot testing phase and must have been demonstrated successfully on full-scale operations for a sufficient period. Theoretical, experimental, or developing technologies are not "available" under RACT. A control technology is neither demonstrated nor available if government subsidies are required to fund evaluations of the technology. In many cases, a technology is not "available" for all sizes of a unit. A control technology must also be "commercially available." This means that the technology must be offered for sale through commercial channels with commercial terms.

The following categories of technologies are addressed in identifying candidate control alternatives:

- Demonstrated add-on control technologies applied to the same emissions unit at other similar source types;
- Add-on controls not demonstrated for the source category in question but transferred from other source categories with similar emission stream characteristics;
- Combustion controls;
- Add-on control devices serving multiple emission units in parallel; and
- Equipment or work practices, especially for fugitive or area emission sources where add-on controls are not feasible.

There is no specific methodology that is required to be used to identify all available emission control technologies and levels for a given source or pollutant. The most comprehensive source of this information, however, is EPA's RACT/BACT/LAER Clearinghouse (RBLC). This searchable database of emission control technology determinations is maintained by EPA, and as such is generally the starting point for developing the required ranking of emission control technologies and levels.

Step 2 – Technical Feasibility

The second step is an evaluation of the technical feasibility of the identified alternatives and to reject those that can be demonstrated as technically infeasible based on an engineering evaluation or on chemical or physical principles. The following criteria were considered in determining technical feasibility: previous commercial-scale demonstrations, precedents based on issued PSD permits, state requirements for similar sources, technology transfer, and engineering evaluations for the control devices or work practice standards considered.

Step 3 – Economic Feasibility/Cost Effectiveness

The economic evaluation is carried out using procedures recommended by the EPA's Office of Air Quality Planning and Standards (OAQPS) Air Pollution Control Cost Manual[2]. The economic evaluation looks at the annualized control cost (in dollars per ton of emissions removed) for a particular control technology or level on the source under consideration in comparison to commonly accepted values for cost effective emission controls established by the state regulatory agency. As noted above, this is a site-specific evaluation and the fact that a particular technology or level of emissions control has been concluded to be representative of RACT at another facility does not mean that the same technology or level constitutes RACT for the existing units at the CGS and SPGS.

Step 4 – Benefits and Disbenefits

The fourth step consists of an objective evaluation of the advantages and disadvantages of each alternative, including any significant or unusual impacts to other media (i.e., water, solid waste, etc.) as well as adverse energy or environmental impacts, including emissions of toxic or hazardous air pollutants.

Step 5 – Identification of RACT

The final step in the process is to summarize the selection of RACT and propose the associated emission limits or work practices to be incorporated into the permit plus any recommended recordkeeping and monitoring conditions that should be incorporated into the final permit.

[2] EPA, *EPA Air Pollution Control Cost Manual*, at Sec. 1, Ch. 2 (7th ed. 2018).

3.0 Baseline Actual and Future Projected Actual Emissions

All the emission units that are the subject of this study are operated in an intermittent fashion when dispatched in order to supply electricity to the grid during periods of peak power demand. Typically, the units operate more often in the summer months; however, they are dispatched as needed year-round. In the most recent five years, the annual output of each unit has been considerably lower than its potential output capacity, as show in Table 3-1.

Table 3-1: Actual Output Data by Unit, 2017 – 2021 (MWhr/yr)

	Potential Output	Actual Output				
		2017	2018	2019	2020	2021
Clark Generating Station						
Unit 4	525,600	4,350	3,250	2,015	10,943	17,707
Unit 5	744,600	72,227	88,783	66,925	87,402	117,764
Unit 6	744,600	86,463	91,634	84,984	77,873	117,951
Unit 7	744,600	80,284	82,879	68,327	129,027	126,882
Unit 8	744,600	79,151	89,259	76,214	83,564	96,725
Unit 11	202,650	21,416	33,513	16,589	18,404	28,387
Unit 12	202,650	34,688	32,454	28,157	30,653	22,883
Unit 13	202,650	28,128	23,589	21,095	18,990	10,765
Unit 14	202,650	43,764	33,120	19,131	25,996	17,941
Unit 15	202,650	31,858	34,273	16,704	22,698	33,541
Unit 16	202,650	36,170	29,384	20,436	18,298	21,002
Unit 17	202,650	26,994	30,284	21,051	27,078	20,173
Unit 18	202,650	38,072	27,171	17,473	16,674	25,388
Unit 19	202,650	23,974	22,509	17,456	26,737	27,515
Unit 20	202,650	29,111	36,092	22,813	25,045	17,247
Unit 21	202,650	25,809	29,854	17,456	10,366	21,328
Unit 22	202,650	24,342	20,216	11,536	17,533	26,109
Sun Peak Generating Station						
Unit 3	370,110	8,564	12,260	19,099	51,180	28,192
Unit 4	370,110	6,373	8,603	14,128	34,258	25,928
Unit 5	370,110	5,083	11,273	21,097	33,306	19,502

As a consequence of each unit's low actual output level, annual NOx and VOC emissions from each unit over the past five years have also been low. Table 3-2 summarizes the actual annual NOx emission rates from the units at the CGS and the SPGS over the past five years, and Table 3-3 summarizes the annual actual VOC emission rates from the units at the CGS over the past five years.

Table 3-2: Actual NOx Emissions by Unit, 2017 – 2021 (tons/yr)

	2017	2018	2019	2020	2021
Clark Generating Station					
Unit 4	8.70	11.32	5.41	27.74	47.56
Unit 5	10.20	13.40	10.00	11.90	14.26
Unit 6	10.40	10.80	9.80	9.29	12.25
Unit 7	7.90	10.10	9.30	13.33	15.27
Unit 8	11.20	12.20	10.70	11.16	12.83
Unit 11	2.95	4.19	2.31	2.49	3.24
Unit 12	4.68	3.38	3.21	3.48	2.60
Unit 13	3.24	2.45	2.60	2.39	1.24
Unit 14	5.33	3.41	2.12	2.78	2.27
Unit 15	3.39	3.27	1.69	2.47	3.60
Unit 16	3.70	2.80	2.01	2.53	2.34
Unit 17	3.22	3.21	2.19	3.10	2.12
Unit 18	4.25	2.61	1.90	1.78	2.85
Unit 19	3.13	2.71	2.16	3.32	2.96
Unit 20	4.19	3.80	2.66	2.66	1.90
Unit 21	3.08	3.13	2.17	1.21	2.26
Unit 22	3.25	2.44	1.49	2.10	2.68
Sun Peak Generating Station					
Unit 3	6.73	9.98	15.81	41.56	22.81
Unit 4	5.10	6.94	11.69	27.64	20.96
Unit 5	4.04	8.94	16.98	26.40	15.45

Table 3-3: Actual CGS VOC Emissions by Unit, 2017 – 2021 (tons/yr)

	2017	2018	2019	2020	2021
Unit 4	0.52	0.62	0.29	1.51	2.59
Unit 5	2.29	2.95	2.11	2.68	4.85
Unit 6	2.53	2.78	2.43	2.20	4.90
Unit 7	1.83	2.69	2.03	3.81	5.32
Unit 8	2.44	2.89	2.27	2.49	4.27
Unit 11	0.26	0.42	0.19	0.21	0.52
Unit 12	0.44	0.40	0.32	0.35	0.42
Unit 13	0.34	0.29	0.24	0.21	0.20
Unit 14	0.54	0.41	0.22	0.30	0.34
Unit 15	0.39	0.42	0.19	0.26	0.59
Unit 16	0.44	0.36	0.23	0.21	0.38
Unit 17	0.33	0.37	0.24	0.31	0.37
Unit 18	0.47	0.34	0.20	0.20	0.48
Unit 19	0.30	0.28	0.20	0.31	0.50
Unit 20	0.36	0.44	0.26	0.29	0.32
Unit 21	0.32	0.37	0.20	0.12	0.39
Unit 22	0.30	0.25	0.13	0.20	0.47

With respect to the expected future operation of these units, as part of its Life Span Analysis Process (LSAP), NV Energy periodically makes planning forecasts of the annual output levels for each of the combustion turbine assets at the CGS and SPGS. Table 3-4 compares the average of the forecasted annual output levels for each unit over the course of the next ten years (i.e., 2023 – 2032) with the maximum two-year annual average output for each unit in the past five years. This comparison demonstrates that the forecasted future average output of each of these assets is less than their actual annual average output over the past five years.

Table 3-4: Comparison – Actual and Forecasted Future Annual Output by Unit

		Maximum Annual (Two-Year Average) Actual Output (MWhr/yr)	Forecasted Future Annual Average Output (MWhr/yr)
Clark Generating Station	Unit 4	14,325	1,445
	Unit 9[1]	218,099	209,302
	Unit 10[2]	200,495	190,997
	Unit 11	27,465	15,980
	Unit 12	33,571	14,820
	Unit 13	25,859	16,209
	Unit 14	38,442	14,221
	Unit 15	33,065	13,439
	Unit 16	32,777	13,638
	Unit 17	28,639	13,277
	Unit 18	32,621	12,137
	Unit 19	27,126	11,574
	Unit 20	32,602	11,325
	Unit 21	27,832	11,000
	Unit 22	22,279	10,073
Sun Peak Generating Station	Unit 3	39,686	4,797
	Unit 4	30,093	5,313
	Unit 5	27,201	5,983
Notes: 1 – CGS combined cycle Unit 9 is made up of combustion turbine Unit Nos. 7 and 8 2 – CGS combined cycle Unit 10 is made up of combustion turbine Unit Nos. 5 and 6			

Therefore, NV Energy asserts that the highest two-year actual annual average emissions rate from each unit over the past five years represents a conservative prediction of the unit's future projected actual emissions over the next ten years. The projected future actual emission rates calculated on this basis are shown below in Table 3-5.

Table 3-5: Projected Future Actual Emission Rates by Unit

		NOx Emissions (ton/yr)	VOC Emissions (ton/yr)
Clark Generating Station	Unit 4	37.65	2.05
	Unit 5	13.08	3.77
	Unit 6	10.77	3.55
	Unit 7	14.30	4.57
	Unit 8	12.00	3.38
	Unit 11	3.57	0.37
	Unit 12	4.03	0.42
	Unit 13	2.85	0.32
	Unit 14	4.37	0.48
	Unit 15	3.33	0.43
	Unit 16	3.25	0.40
	Unit 17	3.22	0.35
	Unit 18	3.43	0.41
	Unit 19	3.14	0.41
	Unit 20	4.00	0.40
	Unit 21	3.11	0.35
	Unit 22	2.85	0.34
Sun Peak Generating Station	Unit 3	32.19	*
	Unit 4	24.30	*
	Unit 5	21.69	*
* - The SPGS units are not subject to RACT for VOC			

4.0 RACT for Nitrogen Oxides Emissions

4.1 Formation

NO_x emissions are formed in combustion sources in three ways: 1) the combination of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal NOx), 2) the oxidation of nitrogen contained in the fuel (fuel NOx), and 3) the reaction of molecular nitrogen with certain free radical compounds (e.g., CN, NH_2) that are typically present in the fuel-rich zones of a combustion flame. Although natural gas contains free nitrogen, it does not contain fuel bound nitrogen, and at typical combustor conditions, the contribution of free radical-based (or "prompt") NOx formation is relatively small. Therefore, the most predominant formation mechanism for NOx emissions from natural gas fired combustion turbine units is thermal NOx. The rate of formation of thermal NOx is a function of residence time and free oxygen concentration; it increases exponentially with increasing peak flame temperature.

"Front end" NOx control techniques are aimed at controlling thermal NOx and/or fuel NOx. The two primary front-end combustion control types for combustion turbine systems include water or steam injection into the combustor and specific combustor design features. The addition of an inert diluent such as water or steam into the high temperature region of the combustor decreases NOx formation by quenching peak flame temperature. Combustor design improvements, specifically the development of dry low-NOx (DLN) combustors, limit peak flame temperature and excess oxygen with lean, pre-mix flames that decrease NOx formation to levels that are equal or better than achieved via water or steam injection when burning natural gas.

Other control methods, known as "back-end" or post combustion controls and described in greater detail in the following subsections, remove NOx from the exhaust gas stream once it has been formed.

4.2 Description of Existing NOx Controls

The three simple-cycle combustion turbine units at the SPGS (Units 3, 4, and 5) are equipped with water injection to control NOx emissions and are required to meet a NOx emission limit of 42 ppmv @ 15% O2. Each unit is limited to an operating schedule of 12 hours per day.

At the CGS, the simple-cycle Unit 4 is not equipped with NOx controls; the unit is subject to an annual potential-to-emit limit of 1,732.6 tons NOx/yr but is not subject to short-term limits, either on an exhaust concentration basis (i.e., ppmv) or mass basis (pounds per hour). The combined-cycle units (Units 5, 6, 7, and 8) are equipped with Ultra Low NOx Burners (ULNB), a type of DLN combustors; collectively these four units are subject to an annual NOx limit of 360 tons/yr and each unit is subject to short-term limit NOx limits of 5 ppm @ 15% O2, expressed on a one-hour average, and 19.11 pounds per hour. The simple-cycle Units 11 – 22 are equipped with selective catalytic reduction (SCR) systems and each unit is subject to an annual NOx limit of 30.96 tons/yr and short-term limits of 5 ppm @ 15% O2 (one hour average) and 11.01 lb/hr. Units 11 – 22 are also each subject to an annual operating limit of 3,500 hours per year.

4.3 Step 1 - Available NOx Control Alternatives

Available control technologies to reduce NOx emissions include SCR systems, DLN combustors, and water or steam injection which are each discussed in the following sections.

Selective Catalytic Reduction (SCR)

SCR is a process which involves post combustion removal of NOx from the flue gas with a catalytic reactor. In the SCR process, ammonia injected into the combustion turbine exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. The SCR process converts nitrogen oxides to nitrogen and water by the following chemical reactions:

$$4\,NO + 4\,NH_3 + O_2 \rightarrow 4\,N_2 + 6\,H_2O \qquad (1)$$

$$6\,NO + 4\,NH_3 \rightarrow 5\,N_2 + 6\,H_2O \qquad (2)$$

$$2\,NO_2 + 4\,NH_3 + O_2 \rightarrow 3\,N_2 + 6\,H_2O \qquad (3)$$

$$6\,NO_2 + 8\,NH_3 \rightarrow 7\,N_2 + 12\,H2O \qquad (4)$$

$$NO + NO_2 + 2\,NH_3 \rightarrow 2\,N_2 + 3\,H_2O \qquad (5)$$

The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NOx decomposition reactions. Technical factors related to this technology include increased turbine backpressure, exhaust temperature materials limitations, thermal shock/stress during rapid starts, catalyst masking/blinding, reported catalyst failure due to "crumbling," design of the NH_3 injection system, and high NH_3 slip.

For most SCR catalyst formulations, the NOx reduction reactions take place within the temperature range of 650 to 850°F. For combined-cycle units, the catalyst grid is installed within the heat recovery steam generator at a location where the combustion turbine exhaust temperature has been reduced by the steam generating banks to within this range. For SCR to be technically feasible on simple-cycle units, which typically have exhaust gas temperatures that are higher than the normal range of SCR catalyst effectiveness, either special high-temperature catalyst formulations must be employed, or the turbine exhaust must be cooled prior to introducing it into the SCR reactor. The most common mechanism used to cool simple cycle turbine exhaust gas is to mix it with a sufficient quantity of ambient air.

SCR catalyst materials lose activity over time, necessitating catalyst cleaning or replacement. In base-loaded natural gas-fired applications, expected SCR catalyst life is within the range of 32,000 to 80,000 operating hours.[3] Catalyst life is lower in simple cycle applications as frequent temperature cycling associated with episodic use causes catalyst sintering and loss of activity.

Dry Low NOx Combustors

Combustion control techniques that utilize design and/or operational features of the turbine's combustors which reduce NOx emissions without injecting an inert diluent (water or steam) are generically referred to as "dry" Low NOx (DLN) measures. The design features of a DLN combustor design are vendor-specific, but generally DLN combustors seek to reduce thermal NOx formation by controlling peak combustion temperature, combustion zone residence time, and combustion zone free oxygen concentration. Alternatives include combustion distribution over several burner stages and pre-mixing air and fuel prior to injection into the combustion zone. These measures produce a lean, pre-mixed flame that burns at a lower flame temperature and excess oxygen levels than conventional combustors.

[3] EPA Air Pollution Control Cost Manual, Section 4 Chapter 2 "Selective Catalytic Reduction" (June 2019)

Water or Steam Injection

Water or steam injection as a NOx control alternative was concluded to represent the Best Demonstrated Technology (BDT) for control of NOx emissions from stationary combustion turbines when the original NSPS for this source category was promulgated in 1977[4]. This alternative involves the injection of water or steam into the high temperature region of the combustor flame. Thermal NOx formation is minimized with this alternative because peak combustion temperature, combustion zone residence time, and combustion zone free oxygen are all reduced. Water or steam injection also serves to augment a combustion turbine's power output due to the additional mass of fluid it provides through the turbine section.

4.4 Steps 2-3 - Technical Feasibility Assessment and Ranking of NOx Control **Alternatives**

Searches of EPA's RBLC were carried out to identify listings containing NOx BACT or RACT determinations for large natural gas-fired combined-cycle and simple-cycled units permitted since 2012. The results of these RBLC searches are summarized in Appendix A, Tables A-1 and A-2.

Among the combined-cycle unit listings in the RBLC that met these criteria there are 150 listings that identify the NOx emission control alternative. The following provides a breakdown of these listings for the emission control alternatives employed:

- 142 list the use of SCR (either alone or in conjunction other alternatives),
- 101 list the use of DLN combustors,
- 4 list water or steam injection,
- 6 list natural gas or clean fuels, and
- 10 list good combustion practices.

Consequently, the use of SCR, DLN, and water or steam injection are technically feasible alternatives for control of NOx emissions from natural gas-fired combined cycle units.

Among the simple-cycle unit listings, there are 56 listings in which the NOx emission control alternative that is employed is described. The breakdown in emission control alternatives used by these simple cycle units is as follows:

- 13 list the use of SCR,
- 42 list the use of DLN combustors,
- 9 list water or steam injection,
- 10 list natural gas or clean fuels, and
- 10 list good combustion practices.

Thus, for simple-cycle units, SCR, DLN combustors, and water or steam injection are all considered a technically feasible alternatives for control of NOx emissions.

The top-level control of NOx emissions for natural gas-fired combined-cycle units is the use of DLN combustors to minimize NOx formation in conjunction with the use of SCR, followed by the use of DLN or water injection alone. Good combustion practices would represent the lowest level of NOx control for this source type. The RBLC limits for combined-cycle units using SCR and DLN range from 2 to 15 ppmvd @15% O_2. The limits for combined-cycle units using DLN alone range from 5 to 41 ppmv @15% O_2. The emission limit for the only combined-cycle unit listed as using water or

[4] 42 Fed. Reg. 53,782, 53,785 (Oct. 3, 1977).

steam injection alone (without SCR or DLN combustors) is 25 ppmvd @ 15% O_2. Accordingly, the hierarchy of NOx emission controls for natural gas-fired combined-cycle units is as follows:

- SCR, either alone or in combination with DLN,
- DLN alone, and
- Water or steam injection alone

For natural gas-fired simple-cycle units, the top level of NOx emissions control is similarly the use of SCR in combination with DLN combustors. The RBLC limits for simple-cycle units employing these technologies together range from 2 – 5 ppmvd @ 15% O_2. The limits for units utilizing DLN alone range from 9 to 30 ppmvd @ 15% O_2. The emission limit for the two simple-cycle units listed as using water or steam injection alone is 25 ppmvd @ 15% O_2. Thus, the hierarchy of NOx emission controls for natural gas-fired simple-cycle units is the same as for natural gas-fired combined-cycle units.

As described previously in Section 1.4.2, the combined-cycle units at CGS (Units 5 – 8) are already equipped with DLN combustors. Thus, the only more stringent NOx control alternative for these units would be to retrofit them with SCR.

Of the simple cycle units at CGS, Unit 4 is not currently equipped with NOx controls, so NOx control alternatives for this unit include both SCR and DLN combustors. As described further below, however, the original equipment manufacturer (GE) has never implemented a DLN retrofit on this type of combustion turbine (i.e., the Frame 7B model). The other simple-cycle units (Units 11 – 22) are already equipped with SCR and therefore retrofitting these units with DLN combustors would be the only available alternative to the existing controls. The simple-cycle units at SPGS utilize water injection to control NOx, so both SCR and DLN combustors are available control alternatives for these units.

4.5 Step 4 – NOx Control Effectiveness Evaluation

Economic Impacts

Installation of either SCR or DLN combustors on the existing combustion turbine units at the CGS and SPGS would entail significant capital and annual costs. Estimates of the cost impacts for these units is provided in the following paragraphs and tables with detailed cost calculations summarized in Appendix B[5]. SCR capital costs are based on recent budgetary estimates for SCR for the various turbine configurations provided by an SCR vendor. The capital cost to install DLN combustors are from a budgetary estimate provided by GE specific to each combustion turbine type.

Table 4-1 summarizes the economic impact of retrofitting SCR and/or DLN combustors (if available) on the simple-cycle GE Frame 7B CGS Unit 4. As noted above, GE has stated that they have never retrofit DLN combustors on the Frame 7B series combustion turbines; they indicated that installing this technology on this unit would constitute a custom retrofit situation that would require a feasibility study be carried out to confirm that the retrofit was technically feasible. Although EPA has previously stated that sources are not expected to experience trials or research to learn how to apply a particular emission control alternative on a source[6], for the purpose of this RACT assessment NV Energy assumes that retrofitting the unit with DLN combustors is a technically feasible

[5] Appendix B contains cost calculations for CGS Units 4 – 9 and SPGS Units 3 – 5. Detailed cost calculations were not carried out for CGS Units 11 – 22 as these units are already equipped with emission controls that are representative of RACT

[6] EPA OAQPS New Source Review Workshop Manual, Section IV. B (1990).

alternative for CGS Unit 4. The total installed cost estimate for retrofitting DLN combustors onto this unit was provided by GE; equipment and direct installation costs for SCR were provided by a vendor of this equipment.

Annualized costs include capital recovery (estimated assuming a 20-year equipment life and NV Energy's Public Utility Commission-approved capital recovery rate of 7.14%, see page 9, item 4 of Appendix C), operating and equipment maintenance costs, and for SCR the cost of ammonia. Ammonia costs are estimated using the current unit cost for this material used in CGS Units 11 – 22 and a reagent consumption rate calculated from the estimated annual NOx reduction level. Operating and maintenance costs are estimated using factors presented in the EPA's OAQPS Control Cost Manual. Described further below, implementation of SCR would have a negative impact on the electrical output capacity of the unit, and thus annual costs for this alternative also include capacity replacement and lost power charges. Annualized DLN costs, however, do not include higher fuel usage due to the change in the unit's heat rate that would likely occur with the use of DLN combustors.

As described in Section 4.2, CGS Units 5 – 8 are already equipped with DLN combustors and are subject to NOx emission limit of 5 ppmv @15% O2. Based on the RBLC search results, this permit limit is within the range of limits that have been concluded to be representative of BACT for combined-cycle units that are equipped with SCR. While it may be technically feasible to retrofit these units with SCR to further reduce their emission levels, this alternative would result in minimal reduction in NOx emissions due to the low annual utilization rate of these units and their already-low emission limit. The capital cost to install SCR on each of these units would be expected to be nearly the same as the cost to retrofit this alternative on to the similarly sized CGS Unit 4. Given their lower baseline emissions rate, however, the use of SCR on these units would be expected to be even less cost effective than it would be on CGS Unit 4.

Table 4-1: Estimated Economic Impact of Alternative NOx Controls: CGS Unit 4

	SCR & DLN Combustors	SCR	DLN Combustors
Baseline Emissions Level (ton/yr)	37.65		
Achievable Emissions Level (ton/yr)	0.6	1.3	7.8
Annual Emissions Reduction (tons/yr)	37.02	36.39	29.77
Total Installed Capital Cost	$40,262,200	$21,262,200	$19,000,000
Annualized Capital Cost	$3,841,000	$2,028,400	$1,812,600
Annual O&M Cost	$400,300	$325,000	$95,000
Total Annual Cost	$4,241,300	$2,353,400	$1,907,600
Cost Effectiveness ($/ton removed)	$114,578	$64,672	$64,069

The estimated economic impacts of retrofitting SCR or DLN combustors on the simple cycle SPGS Units 3 – 5 are shown on Tables 4-2 through 4-4. Capital costs are based on estimated equipment and direct installation costs for these size units provided by an equipment vendor. Annualized costs for this alternative were estimated in the same fashion that the corresponding annualized costs were estimated for CGS Unit 4, (described above), including an estimated 20-year equipment life for the emission control equipment. Considering that the SCR equipment vendors contact stated that the lowest NOx emission level found in the RBLC search (2 ppmv @ 15% O2) could be achieved on these units using SCR alone, any further reduction in emissions that might potentially be achieved by retrofitting SCR in combination with DLN on these units was not considered to be feasible. Thus, for these units the available NOx control alternatives consist of retrofitting the units either with SCR or DLN combustors.

Table 4-2: Estimated Economic Impact of Alternative NOx Controls: SPGS Unit 3

	SCR	DLN Combustors
Baseline Emissions Level (ton/yr)	32.19	
Achievable Emissions Level (ton/yr)	1.75	7.85
Annual Emissions Reduction (tons/yr)	30.44	24.33
Total Installed Capital Cost	$26,151,300	$14,208,900
Annualized Capital Cost	$2,494,800	$1,355,500
Annual O&M Cost	$359,700	$906,300
Total Annual Cost	$2,854,500	$2,261,800
Cost Effectiveness ($/ton removed)	$93,779	$92,978

Table 4-3: Estimated Economic Impact of Alternative NOx Controls: SPGS Unit 4

	SCR	DLN Combustors
Baseline Emissions Level (ton/yr)	24.30	
Achievable Emissions Level (ton/yr)	1.34	6.04
Annual Emissions Reduction (tons/yr)	22.96	18.26
Total Installed Capital Cost	$26,151,300	$14,208,900
Annualized Capital Cost	$2,494,800	$1,355,500
Annual O&M Cost	$350,800	$823,700
Total Annual Cost	$2,845,600	$2,179,200
Cost Effectiveness ($/ton removed)	$123,944	$119,316

Table 4-4: Estimated Economic Impact of Alternative NOx Controls: SPGS Unit 5

	SCR	DLN Combustors
Baseline Emissions Level (ton/yr)	21.69	
Achievable Emissions Level (ton/yr)	1.18	5.33
Annual Emissions Reduction (tons/yr)	20.51	16.36
Total Installed Capital Cost	$26,151,300	$14,208,900
Annualized Capital Cost	$2,494,800	$1,355,500
Annual O&M Cost	$347,900	$796,500
Total Annual Cost	$2,842,700	$2,122,000
Cost Effectiveness ($/ton removed)	$138,633	$131,553

Energy impacts

There are adverse energy impacts associated with the use of either SCR or DLN combustors to reduce NOx emissions. With SCR, the required catalyst grid reduces the electrical generating capacity of a combustion turbine system because the catalyst grid causes backpressure within the turbine and reduces its efficiency. Similarly, DLN combustors have lower combustion efficiency than conventional combustors, which adversely affect the fuel efficiency of these units. In addition to these power generation efficiency losses, NV Energy would need to purchase additional generating capacity elsewhere to maintain the total system generating capacity that would be lost by equipping these combustion turbines with either SCR or DLN combustors. These energy cost impacts are included in the estimated O&M costs for each control option shown in Tables 4-1 to 4-4. For the CGS Unit 4 and the SPGS Units 3 - 5, replacing the existing combustors with DLN combustors would also incur an energy penalty; for the combustors on SPGS Units 3 – 5 that employ water injection, the power loss would be due to the loss of the power augmentation that accompanies the use of water injection for NOx control. Based on information from GE, the energy penalty for CGS Unit 4 would be up to 4% of the rated output capacity; the penalty for SPGS Units 3 – 5 would be up to 9% of their output capacity.

Environmental Impacts

The use of SCR requires that a reducing agent (ammonia) be injected into the turbine exhaust to react with NOx. This creates two forms of adverse environmental impacts. Ammonia that is not consumed in the SCR system is discharged to the atmosphere as ammonia slip, and excess ammonia can react with SO_2 and SO_3 in the turbine exhaust to form ammonium salt compounds (ammonium sulfate and ammonium bisulfate) which can foul downstream heat transfer equipment and/or be subsequently discharged as particulate matter. In addition, the use of an SCR can increase the formation of sulfuric acid emissions by oxidizing a portion of the turbine's SO_2 emissions to SO_3 which subsequently reacts with water vapor to form sulfuric acid. Also, the catalyst must periodically be regenerated and must be disposed of or recycled at the end of its useful life.

There are no adverse environmental impacts, however, associated with DLN combustors.

4.6 Step 5 - Evaluation of RACT for NOx Control

Available NOx control alternatives for the existing simple-cycle and combined-cycle combustion turbines at CGS and SPGS consist of retrofitting the units SCR systems or DLN combustors. However, considering the low rates that these units have historically and are projected to operate in the future, only modest reductions in NOx emissions from these units would be realized by implementing these alternatives. In each instance, installing SCR systems or DLN combustions would entail substantial capital and annual operating expenses, and therefore the cost effectiveness of these alternatives on each combustion turbine unit is estimated to be extremely unreasonable.

Clark Generating Station Unit 4: Retrofitting this simple-cycle unit with both DLN combustors and SCR is projected to result in an annual reduction in NOx emissions of 37.02 tons/yr at an estimated annualized cost of over $4.2 million per year. This alternative is thus concluded to be unrepresentative of RACT on the basis of adverse economic impact due to an estimated cost effectiveness of over $115,000 per ton removed. Retrofitting the unit with just SCR is projected to result in an annual reduction in NOx emissions of 36.39 tons/yr at an estimated annualized cost of over $2.3 million per year. Similarly, with an estimated cost effectiveness of over $64,000 per ton removed, this alternative is concluded to be unrepresentative of RACT on the basis of adverse economic impact. Finally, retrofitting this unit with DLN combustors may not be technically feasible with this unit; even if it were feasible, the estimated cost effectiveness of this alternative (with an estimated annual reduction of NOx emissions of only 7.8 tons/yr and an estimated annualized cost impact of over $1.9 million per year) would also be over $64,000 per ton removed and therefore unrepresentative of RACT on the basis of cost. Therefore NV Energy concludes that RACT for NOx for this unit is the current emission level (1,732.6 tpy) with the current combustion turbine configuration. No changes to the existing emission limits, monitoring, recordkeeping, or reporting requirements are needed to demonstrate compliance.

Clark Generating Station Units 5 – 8: These combined-cycle units are all equipped with DLN combustors and subject to an emissions limit of 5 ppmv @ 15% O2, one-hour average. Although retrofitting them with SCR would be technically feasible, the high capital and annualized operating expense of this alternative is unjustifiable considering the relatively limited schedule under which they have operated and are projected to operate in the future. Therefore, NV Energy concludes that RACT for NOx from these units is their current emission level. The units are equipped with CEMS for NOx, which is proposed as the NOx RACT compliance monitoring method for these units. No changes to the existing emission limits, monitoring, recordkeeping, or reporting requirements are needed to demonstrate compliance.

Clark Generating Station Units 11 – 22: These simple-cycle units are all equipped with SCR and subject to an emissions limit of 5 ppmv @15% O2, one-hour average. The units are limited to an annual operating schedule of 3,500 hours per year, but have in the recent past have operated at around 20% of this level. NV Energy concludes that NOx RACT for these units is their current emissions level. The units are equipped with CEMS for NOx, which is proposed as the NOx RACT compliance monitoring method for these units. No changes to the existing emission limits, monitoring, recordkeeping, or reporting requirements are needed to demonstrate compliance.

Sun Peak Generating Station Units 3 – 5: The Sun Peak simple-cycle units utilize water injection to control NOx emissions to a limit of 42 ppmv @15% O2, three-hour average. The units are limited to an operating schedule of 12 hours per day and are typically only operated for a few hours per day. Retrofitting them with SCR is technically feasible but not cost effective given their limited projected operating schedule. Annualized operating costs for each unit are estimated at over $2.8 million per year with cost effectiveness levels for each unit estimated between $93,700 and $138,600 per ton of NOx removed. Similarly, retrofitting these units with DLN combustors would be technically feasible but cost ineffective; the estimated annualized cost of this alternative on these units is $2.1 million per year and cost effectiveness levels for the three units range from $92,900 to $131,500 per ton of NOx removed. Therefore, NV Energy concludes that the current means of NOx control on these units is representative of RACT. The units are equipped with CEMS for NOx, which is proposed as the NOx RACT compliance monitoring method for these units. No changes to the existing emission limits, monitoring, recordkeeping, or reporting requirements are needed to demonstrate compliance.

5.0 RACT for Volatile Organic Compound (VOC) Emissions

5.1 Formation

VOC emissions are generated in combustion turbines due to the incomplete conversion of carbon-containing compounds to CO_2 and water during fuel combustion. VOC emission rates are principally influenced by equipment operating conditions. Higher VOC emissions may be the result of lower than optimal combustion temperature, insufficient combustor residence time, and lower operating loads.

5.2 Step 1 - Available VOC Control Alternatives

Available control technologies to reduce VOC emissions from combined cycle units include oxidation catalyst and combustion controls/good combustion practices.

Oxidation Catalyst

An oxidation catalyst is a post-combustion technology that removes VOC from the exhaust gas stream after it is formed in the combustion turbine. In the presence of a catalyst, VOC will react with oxygen present in the turbine exhaust, converting it to carbon dioxide. The activation energy required for the oxidation reactions to proceed is lowered in the presence of the catalyst. Technical factors relating to this technology include the catalyst reactor design, optimum operating temperature, back pressure loss to the system, catalyst life, and potential collateral increases in emissions of particulate matter and sulfuric acid mist.

VOC catalytic oxidation systems operate in a relatively narrow temperature range. At lower temperatures, VOC conversion efficiency falls off rapidly. At higher temperatures, catalyst sintering may occur, thus causing permanent damage to the catalyst. For this reason, in combined-cycle combustion turbines the oxidation catalyst is placed within the HRSG at a location that is selected to ensure that the proper operating temperature is maintained, considering the temperature variations that are expected to occur across the unit's operating load range. Simple-cycle combustion turbines employing oxidation catalyst systems typically are equipped with the means to reduce the temperature of the turbine exhaust prior to introducing it into the catalytic reactor.

Catalyst life may vary from the manufacturer's typical 3-year guarantee to a 5- to 6-year predicted life. Periodic testing of catalyst material is necessary to predict annual catalyst life for a given installation to minimize VOC emissions.

No supplementary reactant is used in conjunction with an oxidation catalyst. The performance of an oxidation catalyst system is dependent on the specific VOC constituents present in the turbine exhaust.

Good Combustion Practices

As noted above, VOCs are formed during the combustion process as a result of incomplete combustion of the carbon present in the fuel. The formation of VOC is limited by designing and operating the combustion system to maximize oxidation of the fuel carbon to CO_2. Good combustion practices consisting primarily of controlled fuel/air mixing and adequate temperature and gas residence time within the turbine combustor will minimize the formation of VOCs.

5.3 Step 2 - Technical Feasibility Assessment and Ranking of VOC Control Alternatives

Searches of EPA's RBLC were performed to identify large natural gas-fired combined-cycle and simple-cycle units permitted since 2012 with BACT or RACT determinations for VOC. The results of these RBLC searches are summarized in Appendix A, Tables A-3 and A-4.

The search among the combined-cycle unit listings found 128 listings that identify the VOC emission control alternative. The breakdown of these listings by emission control alternatives employed is as follows:

- 112 list the use of oxidation catalyst,
- 79 list good combustion practices, and.
- 19 list natural gas or clean fuels.

For the listings of simple-cycle units, the search identified 39 listings that identify the VOC emission control alternative. The breakdown of emission control alternatives identified in these listings is as follows:

- 15 list the use of oxidation catalyst,
- 31 list good combustion practices, and.
- 11 list natural gas or clean fuels.

Thus, oxidation catalyst and combustor design or good combustion practices are considered technically feasible alternatives for control of VOC emissions from natural gas-fired combined-cycle and simple-cycle combustion turbines. The hierarchy of VOC emission controls for natural gas-fired combustion turbines, including both combined-cycle and simple-cycle units, is as follows:

- Oxidation catalyst, either alone or in combination with good combustion practices, and
- Good combustion practices alone.

5.4 Step 4 – VOC Control Effectiveness Evaluation

Available VOC control alternatives for the existing simple-cycle Unit 4 and combined-cycle Units 5 – 8 combustion turbines at CGS consist of either oxidation catalyst systems or good combustion practices.

The existing simple-cycle Units 11 – 22 are already equipped with oxidation catalyst systems, and NV Energy concludes that the existing controls, emission limits, and monitoring method on these units are representative of RACT for VOC.

Considering the low rates that Units 4 – 8 are projected to operate in the future, very small reductions in VOC emissions from these units would be realized by retrofitting them with oxidation catalyst systems. As described further below, the cost effectiveness of oxidation catalyst systems on these units is estimated to be extremely unreasonable.

Economic Impacts

As with SCR, the retrofit of oxidation catalyst systems on the existing combustion turbine units at the CGS would entail significant capital and annual costs. Cost impact estimates for these units, based on budgetary estimates received from an equipment vendor, are provided in the following paragraphs and tables. The estimated emission control effectiveness of this alternative on these units is 80%.

Table 5-1 summarizes the economic impact of retrofitting an oxidation catalyst system on the simple-cycle CGS Unit 4, and on the combined-cycle Units 5 - 8. As with the economic analysis of NOx control alternatives presented in Section 4, annualized costs for each unit include capital recovery (based on a 20-year equipment life and an annual return on capital of 7.14%), annual maintenance costs, catalyst replacement costs, and lost power and capacity replacement charges due to the additional pressure drop imposed by the oxidation catalyst grid.

Table 5-1: Estimated Economic Impact of Retrofitting Oxidation Catalyst Systems: CGS Units 5 - 8

	CGS Unit 4	CGS Unit 5	CGS Unit 6	CGS Unit 7	CGS Unit 8
Baseline Emissions Level (ton/yr)	2.05	3.77	3.55	4.57	3.38
Achievable Emissions Level (ton/yr)	0.41	0.75	0.71	0.91	0.68
Annual Emissions Reduction (tons/yr)	1.64	3.02	2.84	3.65	2.70
Total Installed Capital Cost	$4,366,600	$5,030,300	$5,030,300	$5,030,300	$5,030,300
Annualized Capital Cost	$416,600	$479,900	$479,900	$479,900	$479,900
Annual O&M Cost	$200,800	$262,600	$259,900	$281,700	$261,600
Total Annual Cost	$617,400	$742,500	$739,800	$761,600	$741,500
Cost Effectiveness ($/ton removed)	$376,082	$246,514	$260,493	$208,543	$274,223

Energy Impacts

As with SCR, the required oxidation catalyst grid reduces the combustion turbine system generating capacity due to increased turbine backpressure and reduced efficiency. If these VOC control systems were installed, NV Energy would need to purchase additional generating capacity elsewhere to make up the lost system generating capacity. These energy cost impacts are included in the estimated O&M costs of this control option shown in Table 5-1.

Environmental Impacts

The use of an oxidation catalyst system on either combined-cycle or simple-cycle units has been shown to increase sulfuric acid emissions as a result of oxidation of a portion of the unit's SO_2 emissions to SO_3 and the subsequent reaction of SO_3 with water vapor to form sulfuric acid. The catalyst must also be regenerated periodically and must be disposed of or recycled at the end of its useful life.

There are no environmental impacts associated with the use of combustion controls on either combined-cycle or simple-cycle units.

5.4.1 Step 5 - Evaluation of RACT for VOC Control

Available VOC control alternatives for the existing simple-cycle and combined-cycle combustion turbines at CGS are the use of oxidation catalyst systems and good engineering practices. The existing Units 11 – 22 at the CGS are already equipped with oxidation catalyst systems, and thus this alternative is concluded to represent RACT for these units the existing emissions level of 1.49 pounds per hour. No changes to the existing emission limits, monitoring, recordkeeping, or reporting requirements are needed to demonstrate compliance.

Considering the low rates that CGS Units 4 – 8 are projected to operate in the future, retrofitting these units with oxidation catalyst systems would result in very small reductions in VOC emissions at significant capital and annual operating expenses. As a result, and as summarized in Table 5-1, the cost effectiveness of retrofitting oxidation catalyst systems on these units is estimated to be extremely high. Therefore, the use of this alternative on these units is concluded to be unrepresentative of RACT on the basis of economic impacts.

Consequently, the use of good combustion practices is concluded to represent RACT for CGS Units 4 – 8 at the existing emission levels of 94.5 tons per year of VOC for Unit 4 and 5.01 pounds per hour for Units 5 – 8. No changes to the existing emission limits, monitoring, recordkeeping, or reporting requirements are needed to demonstrate compliance.

Appendix A

RACT/BACT/LAER Clearinghouse Search Results

TABLE A-1: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
*AK-0088	LIQUEFACTION PLANT	AK	7/7/2022	Four Combined Cycle Gas-Fired Turbines	384	MMBtu/hr	SCR, DLN combustors, and good combustion practices	2	PPMV @ 15% O2	3-HOURS
*WV-0033	MAIDSVILLE	WV	1/5/2022	Combustion Turbine & Duct Burner (CT-01/HRSG1 & CT-02/HRSG2)	1275	mw	Dry Low NOx Combustion w/ SCR	2	PPMDV @ 15% O2	3-HOUR ROLLING AVERAGE
*WV-0033	MAIDSVILLE	WV	1/5/2022	Combustion Turbine & Duct Burner (CT-01/HRSG1 & CT-02/HRSG2)	1275	mw	Dry Low NOx Combustor with SCR	2	PPMDV @ 15% O2	3-HOUR ROLLING AVERAGE
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	FL	6/7/2021	GE 7HA.02 Combustion Turbine and HRSG with Duct Firing	3622.1	MMBtu/hour	Dry low-NOX combustors and Selective Catalytic Reduction (SCR)	2	PPMVD AT 15% O2	24-HOUR BLOCK AVERAGE BASIS (BACT)
MI-0447	LBWL--ERICKSON STATION	MI	1/7/2021	EUCTGHRSG1	667	MMBTU/H	Dry low NOx burners and selective catalytic reduction for NOx control for each CTG/HRSG unit.	3	ppmvd @ 15% O2	24 hour rolling average
MI-0447	LBWL--ERICKSON STATION	MI	1/7/2021	EUCTGHRSG2	667	MMBTU/H	Dry low NOx burners and selective catalytic reduction for NOx control for each CTG/HRSG unit.	3	ppmvd @ 15% O2	24 hour rolling average
AL-0328	PLANT BARRY	AL	11/9/2020	Two 744 MW Combined Cycle Units	744	MW	SCR	2	PPM	3 HOUR AVG / @15% O2
*WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Natural-Gas-Fired Combined-Cycle Turbine (P01)	4671	MMBTU/H	Selective Catalytic Reduction (SCR), low-NOx burners, Water injection when firing diesel fuel oil.	2	PPM AT 15% O2	24-HR ROLLING AVG., NATURAL GAS
*PA-0331	GRAYS FERRY COGENERATION PARTNERSHIP - SCHUYLKILL STATION	PA	3/4/2020	Combustion Turbine	1515	MMBTU/hr	SCR	9	ppmvd @ 15% O2	
*WI-0306	WPL- RIVERSIDE ENERGY CENTER	WI	2/28/2020	Natural Gas Fired Combustion Turbine (P20, P21) Phase I Commissioning	2208	MMBTU/H		110	PPMVD, 15% OXYGEN	AVG. ANY 24-HR OPERATIONAL PERIOD
*WI-0306	WPL- RIVERSIDE ENERGY CENTER	WI	2/28/2020	Natural Gas Fired Combustion Turbine (P20, P21)- Startup operation during Phase I Commissioning	2208	MMBTU/H		110	PPMVD, 15% OXYGEN	AVG. ANY 24-HR OPERATIONAL PERIOD
*WI-0306	WPL- RIVERSIDE ENERGY CENTER	WI	2/28/2020	Natural Gas Fired Combustion Turbine (P20, P21) Phase II Commissioning	2208	MMBTU/H		55	PPMVD, 15% OXYGEN	AVG. ANY 24-HR OPERATIONAL PERIOD
LA-0364	FG LA COMPLEX	LA	1/6/2020	Cogeneration Units	2222	mm btu/h	Dry low NOx combustor design along with SCR.	2	PPMVD	12-MONTH ROLLING AVERAGE
*MI-0445	INDECK NILES, LLC	MI	11/26/2019	FGCTGHRSG	3421	MMBTU/H	SCR with DLNB (Selective Catalytic Reduction with Dry Low NOx Burners)	2	PPM	PPMVD @15% O2. 24HR ROLL AVG EXCEPT SS

TABLE A-1: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	MI	8/21/2019	FGCTGHRSG	625	MW	Good combustion practices, dry low NOx burners and selective catalytic reduction (SCR).	2	PPM	EACH; 24-HR ROLL.AVG EXCEPT START/SHUT
NJ-0088	COGEN TECH LINDEN VENTURE LP	NJ	7/30/2019	250 MW COMBINED CYCLE COMBUSTION TURBINE FIRING NATURAL GAS	21042	MMCubic ft/yr	Selective Catalytic Reduction, Dry Low NOx, and use of Natural gas as Primary fuel	2	PPMVD@15%O2	3 H ROLLING AV BASED ON ONE H BLOCK
*LA-0365	BIG CAJUN I POWER PLANT	LA	6/27/2019	Combustion Turbine #1 (EQT0002, CTG-1)	1679	MM BTU/hr	Dry low NOX Burners & water injection	23	PPMV	THREE HOUR ROLLING AVERAGE
*LA-0365	BIG CAJUN I POWER PLANT	LA	6/27/2019	Combustion Turbine #2 (EQT0003, CTG-2)	1679	MM BTU/hr	Dry low NOX burners & water injection	23	PPMV	THREE HOUR ROLLING AVERAGE
VA-0332	CHICKAHOMINY POWER LLC	VA	6/24/2019	Three (3) Mitsubishi Hitachi Power Systems combustion turbine generators	35000	MMCF/YR	Controlled by dry, low NOx burners and selective catalytic reduction (SCR).	2	PPMVD 15% O2	1 HR AVG
MI-0439	JACKSON GENERATING STATION	MI	4/2/2019	FGLMDB1-6 (6 combined cycle natural gas fired CTG each equipped with a HRSG)	420	MW	Steam injection, good combustion practices and only combust natural gas.	25	PPM	AT 15% O2; 30 DAY ROLLING AVG; EACH UNIT
IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Combined-Cycle Combustion Turbine	3864	mmBtu/hr	Selective Catalytic Reduction (SCR) and low-NOx technology (dry low-NOx combustion technology)	2	PPMV	3-UNIT OPERATING HOURS @ 15% O2
MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUCTGHRSG2--A 667 MMBTU/H natural gas fired CTG with a HRSG.	667	MMBTU/H	Dry low NOx burners and selective catalytic reduction for NOx control.	3	PPM	PPMVD@15%O2; 24-H AVG; SEE NOTES
MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUCTGHRSG1--A 667 MMBTU/H NG fired combustion turbine generator coupled with a heat recovery steam generator (HRSG)	667	MMBTU/H	Dry low NOx burners and selective catalytic reduction for NOx control.	3	PPM	PPMVD@15%O2; 24-H ROLL AVG; SEE NOTES
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Combined Cycle Combustion Turbines (CCCT1 to CCCT5)	921	MM BTU/h	Low NOx Burners, SCR, and Good Combustion Practices	2.5	PPMV	30 DAY ROLLING AVERAGE
*WV-0032	BROOKE COUNTY POWER PLANT	WV	9/18/2018	GE 7HA.01 Turbine	2737.7	mmBtu/hr	Dry-Low NOx Burners, SCR	2	PPM	
*PA-0319	RENAISSANCE ENERGY CENTER	PA	8/27/2018	COMBUSTION TURBINE UNIT w/o DUCT BURNERS UNIT	2665.9	MMBtu/hr	SCR	2	PPMDV	@15% O2
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Combined Cycle Combustion Turbines	3474	mmBtu/hr	Selective catalytic reduction (SCR) and low-NOx combustion technology (dry low-NOx combustion technology for natural gas; water injection for ULSD)	2	PPMV @ 15% O2	3-UNIT OPERATING HOURS
MI-0432	NEW COVERT GENERATING FACILITY	MI	7/30/2018	FG-TURB/DB1-3 (3 combined cycle combustion turbine and heat recovery steam generator trains)	1230	MW	Good combustion practices, DLN burners and SCR.	2	PPMVD	AT 15%O2; EACH INDIV. CT/HRSG TRAIN

TABLE A-1: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	FL	7/27/2018	1-on-1 combined cycle unit (GE 7HA)	3266.9	MMBtu/hour	Dry low-NOX combustors and Selective Catalytic Reduction (SCR)	2	PPMVD AT 15% O2	24-HOUR BLOCK AVERAGE BASIS (BACT)
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	FGCTGHRSG (EUCTGHRSG1 & EUCTGHRSG2)			SCR with DLNB (Selective catalytic reduction with dry low NOx burners).	2	PPMVD	AT 15%O2; 24-H ROLL AVG; EACH UNIT;
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUCTGHRSG (South Plant): A combined cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	500	MW	SCR with DLNB (Selective catalytic reduction with dry low NOx burners).	2	PPMV	AT 15%O2; 24-HR ROLL AVG NOT S.S.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUCTGHRSG (North Plant): A combined-cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	500	MW	SCR with DLNB (Selective catalytic reduction with Dry Low NOx burners).	2	PPMVD	AT 15%O2; 24-H ROLL AVG; NOT S.S.
MI-0431	INDECK NILES LLC	MI	6/26/2018	FGCTGHRSG (2 Combined Cycle CTG with HRSGs)	3421	MMBTU/H	SCR with DLNB (Selective Catalytic Reduction with Dry Low NOx Burners)	2	PPM	AT 15%O2; 24-HR ROLL AVG
VA-0328	C4GT, LLC	VA	4/26/2018	GE Combustion Turbine - Option 1 - Normal Operation	34000	MMCF/YR	dry, low NOx burners and selective catalytic reduction	2	PPMVD @ 15% O2	1 H AV
VA-0328	C4GT, LLC	VA	4/26/2018	Siemens Combusion Turbine - Option 2 - Normal Operation	35000	MMCF/YR	DRY, LOW NOx BURNERS & SCR	2	PPMVD @ 15% O2	1 H AV
CA-1251	PALMDALE ENERGY PROJECT	CA	4/25/2018	Combustion Turbines (GEN1 and GEN2)	2217	MMBTU/H	Selective Catalytic Reduction, Dry Low NOx Burners	2	PPM @ 15% O2	1-HOUR
OH-0377	HARRISON POWER	OH	4/19/2018	General Electric (GE) Combustion Turbines (P005 & P006)	3459.6	MMBTU/H	dry low NOx burners and an SCR system	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
OH-0377	HARRISON POWER	OH	4/19/2018	Mitsubishi Hitachi Power Systems (MHPS) Combustion Turbines (P007 & P008)	3231	MMBTU/H	dry low NOx burners and an SCR system	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
TX-0834	MONTGOMERY COUNTY POWER STATIOIN	TX	3/30/2018	Combined Cycle Turbine	2635	MMBTU/HR/UNIT	SCR and Dry Low NOx burners	2	PPMVD	15% O2 1-HOUR AVERAGE
TX-0834	MONTGOMERY COUNTY POWER STATIOIN	TX	3/30/2018	COMBINED CYCLE TURBINE MSS REDUCED LOAD			minimizing duration of startup / shutdown events, engaging the pollution control equipment as soon as practicable (based on vendor recommendations and guarantees), and meeting the emissions limits on the MAERT			
*WV-0029	HARRISON COUNTY POWER PLANT	WV	3/27/2018	GE 7HA.02 Turbine	3496.2	mmBtu/hr	Dry-Low NOx Burners, SCR	2	PPM	
*TN-0164	TVA - JOHNSONVILLE COGENERATION	TN	2/1/2018	Dual-fuel CT and HRSG with duct burner	1020	MMBtu/hr	SCR, good combustion design & practices	2	PPMVD @ 15% O2	30-DAY AVG WHEN BURNING NATURAL GAS
*PA-0316	RENOVO ENERGY CENTER, LLC	PA	1/26/2018	Combustion Turbine Firing NG			SCR	2	PPMDV	CORRECTED TO 15% O2

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PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
MI-0427	FILER CITY STATION	MI	11/17/2017	EUCCT (Combined cycle CTG with unfired HRSG)	1934.7	MMBTU/H	SCR with DLNB (Selective catalytic reduction with dry low NOx burners).	3	PPM	24-H ROLL.AVG., EXCEPT STARTUP/SHUTDOWN
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	11/7/2017	General Electric Combustion Turbine (P004)	3544	MMBTU/H	dry low NOx burners and an SCR system	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	11/7/2017	Mitsubishi Combustion Turbine (P005)	3320	MMBTU/H	dry low NOx burners and an SCR system	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	11/7/2017	Siemens Combustion Turbine (P006)	3602	MMBTU/H	dry low NOx burners and an SCR system	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
OH-0374	GUERNSEY POWER STATION LLC	OH	10/23/2017	Combined Cycle Combustion Turbines (3, identical) (P001 to P003)	3516	MMBTU/H	dry low NOx burners and SCR	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
OH-0372	OREGON ENERGY CENTER	OH	9/27/2017	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	3055	MMBTU/H	Dry low NOX combustors and selective catalytic reduction (SCR)	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
OH-0370	TRUMBULL ENERGY CENTER	OH	9/7/2017	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	3025	MMBTU/H	dry low NOx combustors (DLN) and selective catalytic reduction (SCR)	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
CT-0161	KILLINGLY ENERGY CENTER	CT	6/30/2017	Natural Gas w/o Duct Firing	2969	MMBtu/hr	SCR	2	PPMVD @15% O2	1 HOUR BLOCK
CT-0161	KILLINGLY ENERGY CENTER	CT	6/30/2017	Natural Gas w/Duct Firing	2639	MMBtu/hr	SCR	2	PPMVD @15% O2	1 HOUR BLOCK
TX-0819	GAINES COUNTY POWER PLANT	TX	4/28/2017	Combined Cycle Turbine with Heat Recovery Steam Generator, fired Duct Burners, and Steam Turbine Generator	426	MW	Selective Catalytic Reduction (SCR) and Dry Low NOx burners	2	PPMVD	15% O2 3-H AVG
*PA-0315	HILLTOP ENERGY CENTER, LLC	PA	4/12/2017	Combustion Turbine without Duct Burner	3509	MMBtu/hr		2	PPMDV	CORRECTED TO 15% O2
MI-0423	INDECK NILES, LLC	MI	1/4/2017	FGCTGHRSG (2 Combined Cycle CTGs with HRSGs)	8322	MMBTU/H	SCR with DLNB (selective catalytic reduction with dry low NOx burners)	3	ppmvd @ 15% O2	
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	FGCTGHRSG (2 Combined cycle CTGs with HRSGs; EUCTGHRSG10 & EUCTGHRSG11)	554	MMBTU/H, each	Selective catalytic reduction with dry low NOx burners (SCR with DLNB).	3	PPM AT 15% O2	24-H ROLLING AVG; EACH EU
OH-0367	SOUTH FIELD ENERGY LLC	OH	9/23/2016	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	3131	MMBTU/H	Dry low NOx (DLN) burners for natural gas firing, wet injection when firing ultra low sulfur diesel, and selective catalytic reduction (SCR) for both natural gas and ultra low sulfur diesel.	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Combustion turbine and HRSG with duct burner NG only	3338	MMBtu/hr	Dry Low NOx combustion technology, SCR at all steady state operating loads, good combustion and operating practices	2	PPMDV @ 15% O2	

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PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Combined Cycle Unit 1A	3625	MMBTU/hr	Selective Catalytic Reduction (SCR) with Dry Low NOx Burners (DLNB) during normal operations; Good Combustion Practices during Startup/Shutdown operations.	15	PPM@15% O2	4-HOUR AVERAGE
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Combined Cycle Unit 1B	3625	MMBTU/hr	Selective Catalytic Reduction (SCR) with Dry Low NOx Burners (DLNB) during normal operations, and good combustion practices during startup/shutdown operations.	15	PPM@15% O2	4-HOUR AVERAGE
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas with Duct Burner	4000	h/yr	SELECTIVE CATALYTIC REDUCTION AND DRY LOW NOX	2	PPMVD@15%O2	3 H ROLLING AV BASED ON ONE H BLOCK AV
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas without Duct Burner	8040	H/YR	Selective Catalytic Reduction System and Dry Low NOx	2	PPMVD@15%O2	3 H ROLLING AV BASED ON ONE H BLOCK AV
VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	COMBUSTION TURBINE GENERATOR WITH DUCT-FIRED HEAT RECOVERY STEAM GENERATORS (3)	3227	MMBTU/HR	SCR	2	PPMVD	1 HR AVG
TN-0162	JOHNSONVILLE COGENERATION	TN	4/19/2016	Natural Gas-Fired Combustion Turbine with HRSG	1339	MMBtu/hr	Good combustion design and practices, selective catalytic reduction (SCR)	2	PPMVD @ 15% O2	30 UNIT-OPERATING-DAY MOVING AVERAGE
TX-0788	NECHES STATION	TX	3/24/2016	Large Combustion Turbines >25 MW	232	MW	Dry low-NOx burners (DLN), good combustion practices	9	PPM	
TX-0788	NECHES STATION	TX	3/24/2016	Combined Cycle & Cogeneration	231	MW	Selective Catalytic Reduction	2	PPM	
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Combined Cycle Combustion Turbine with Duct Burner firing natural gas			SCR and use of natural gas a clean burning fuel	2	PPMVD@15%O2	3 H ROLLING AV BASED ON ONE H BLOCK
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Combined Cycle Combustion Turbine without Duct Burner Firing Natural Gas	28169501	MMBTU/YR	SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM	2	PPMVD@15%O2	3 H ROLLING AV BASED ON ONE H BLOCK
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	Combined-cycle electric generating unit	3096	MMBtu/hr per turbi	Selective catalytic reduction; dry low-NOx; and wet injection	2	PPMVD@15% O2	GAS, 24-HR BLOCK, EXCLUDING SSM
TX-0789	DECORDOVA STEAM ELECTRIC STATION	TX	3/8/2016	Combined Cycle & Cogeneration	231	MW	Selective Catalytic Reduction	2	PPM	
PA-0306	TENASKA PA PARTNERS/WESTMORELAND GEN FAC	PA	2/12/2016	Large combustion turbine			SCR, DLN, and good combustion practice	2	PPMVD@15% O2	
PA-0306	TENASKA PA PARTNERS/WESTMORELAND GEN FAC	PA	2/12/2016	Large combustion turbine			SCR, DLN, and good combustion practice	2	PPMVD@15% O2	

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LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
NY-0103	CRICKET VALLEY ENERGY CENTER	NY	2/3/2016	Turbines and duct burners	228	mw	dry low NOx burners in combination with selective catalytic reduction	2	PPMVD @ 15% O2	1 H
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	Combustion turbine with duct burner	3304.3	MMBtu/hr	Dry low-NOx burners, SCR, exclusive natural gas	2	PPMDV @15% O2	
CT-0157	CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/12 months	SCR	2	PPMVD @15% O2	1 HR BLOCK
CT-0158	CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/yr	SCR	2	PPMVD @15% O2	1 HR BLOCK
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES	286	MW	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)	2	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE (EXCLUDING SU/SD)
TX-0773	FGE EAGLE PINES PROJECT	TX	11/4/2015	Combined Cycle Turbines (>25 MW)	321	MW	Selective Catalytic Reduction	2	PPM	24-HR AVERAGE
OK-0169	PSO COMANCHE POWER STATION	OK	10/8/2015	COMBINED CYCLE COMBUSTION TURBINE	1250	MMBTUH	Use of Dry Low NOx Burners	41	ppmvd @ 15% O2	
TX-0767	LON C. HILL POWER STATION	TX	10/2/2015	Combined Cycle Turbines (>25 MW)	195	MW	Selective Catalytic Reduction	2	PPM	ROLLING 24-HR AVERAGE
PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Combustion Turbine With Duct Burner	3727	MMBtu/hr	DLN burner, SCR, good engineering practice	2	PPMDV @ 15% O2	
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	8/25/2015	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	2725	MMBTU/H	dry low NOx combustors, selective catalytic reduction (SCR)	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
PA-0305	SHELL CHEM APPALACHIA/PETROCHEMICALS COMPLEX	PA	6/18/2015	Combustion turbine wih duct burner and heat recovery steam generator	Three 40.6 MW turbines			2	PPMDV @ 15% O2	1 HOUR AVG EX DURING STARTUP AND SHUTDOW
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	TX	6/18/2015	Combined Cycle Turbines (>25 MW) natural gas	210	MW	Selective Catalytic Reduction	2	PPM	ROLLING 24-HR AVERAGE
PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	PA	6/15/2015	Two Combine Cycle Combustion Turbine with Duct Burner	3001.57	MCF/hr	SCR, Dry Lo-NOx combustor, good combustion practices and low sulfur fuels	2	PPVDM @ 15 O2	
KY-0104	CASH CREEK GENERATING STATION	KY	6/10/2015	Combined cycle combustion turnbine with HRSG and duct firing	849	MW	SCR, low NOx burners	2	PPMVD	@15% O2 THREE HOUR ROLLING AVERAGE
OH-0365	ROLLING HILLS GENERATING, LLC	OH	5/20/2015	Combustion Turbines, Scenario 1 (4, identical) (P001, P002, P004, P005)	2022	MMBTU/H	dry-low NOx (DLN) burner and selective catalytic reduction (SCR)	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
OH-0365	ROLLING HILLS GENERATING, LLC	OH	5/20/2015	Combustion Turbines, Scenario 2 (4, identical) (P001, P002, P004, P005)	2144	MMBTU/H	dry-low NOx (DLN) burner and selective catalytic reduction (SCR)	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
TX-0730	COLORADO BEND ENERGY CENTER	TX	4/1/2015	Combined-cycle gas turbine electric generating facility	1100	MW	efficient processes, practices, and designs			

TABLE A-1: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
TX-0730	COLORADO BEND ENERGY CENTER	TX	4/1/2015	Combined-cycle gas turbine electric generating facility	1100	MW	SCR and oxidation catalyst	2	PPMVD @ 15% O2	24-HR AVERAGE
TX-0714	S R BERTRON ELECTRIC GENERATING STATION	TX	12/19/2014	(2) combined cycle turbines	240	MW	Selective Catalytic Reduction	2	PPMVD	@15% O2, 24-HR ROLLING AVERAGE
TX-0710	VICTORIA POWER STATION	TX	12/1/2014	combined cycle turbine	197	MW	Selective Catalytic Reduction	2	PPMVD	@15% O2, 24-HR ROLLING AVERAGE
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Combined Cycle Turbine/Duct Burner	2419.61	mmBtu/Hr	SCR & Dry Low-NOx Burners	2	PPM	@ 15% O2
TX-0712	TRINIDAD GENERATING FACILITY	TX	11/20/2014	combined cycle turbine	497	MW	Selective Catalytic Reduction	2	PPMVD	@15% O2, 24-HR ROLLING AVERAGE
OH-0363	MIDDLETOWN ENERGY CENTER	OH	11/5/2014	Turbine generator with HRSG and duct burners (P001)	3278.5	MMBTU/H	Use of natural gas, low NOx burner, and selective catalytic reduction (SCR).	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	235	MW	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION	2	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD
TX-0689	CEDAR BAYOU ELECTRIC GENERATION STATION	TX	8/29/2014	Combined cycle natural gas turbines	225	MW	DLN, SCR	2	PPM	24HR ROLLING AVG.
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine without Duct Burner	20282	MMCF/YR	Selective Catalytic Reduction System (SCR) and use of natural gas a clean burning fuel	2	PPMVD@15%O2	3-HR ROLLING AVE BASED ON 1-HR BLOCK
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine with Duct Burner	20282	MMCF/YR	Selective Catalytic reduction (SCR) and use of natural gas a clean burning fuel	2	PPMVD@15%O2	3-HR ROLLING AVE BASED ON 1-HR BLOCK
TX-0678	FREEPORT LNG PRETREATMENT FACILITY	TX	7/16/2014	Combustion Turbine	87	MW	Selective Catalytic Reduction	2	PPMVD	15@ O2, 3 HOUR ROLLING AVERAGE
TX-0713	TENASKA BROWNSVILLE GENERATING STATION	TX	4/29/2014	(2) combined cycle turbines	274	MW	Selective Catalytic Reduction	2	PPMVD	@15% O2, 24-HR ROLLING AVERAGE
MD-0041	CPV ST. CHARLES	MD	4/23/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	725	MEGAWATT	DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)	2	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD

TABLE A-1: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	Combustion turbine #1 - combined cycle	2258	mmBtu/hr	Low-NOx burners and SCR	2	PPM	30-DAY ROLLING AVG. @15% O2
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	Combustion turbine #2 -combined cycle	2258	mmBtu/hr	SCR, Low-NOx burner	2	PPM	30-DAY ROLLING AVERAGE
MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITH DUCT FIRING	1000	MW	USE OF DRY LOW-NOX COMBUSTOR TURBINE DESIGN , USE OF PIPELINE QUALITY NATURAL GAS DURING NORMAL OPERATION AND SCR SYSTEM	2	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD
TX-0660	FGE TEXAS POWER I AND FGE TEXAS POWER II	TX	3/24/2014	Alstom Turbine	230.7	MW	Selective catalytic reduction	2	PPMVD	CORRECTED TO 15% O2, ROLLING 24 HR AVE
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	Combined Cycle Combustion Turbine - Siemens turbine without Duct Burner	33691	MMCF/YR	Selective Catalytic Reduction and Dry Low NOx	2	PPMVD@ 15% O2	3-HR ROLLING AVE BASED ON 1-HR BLOCK
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - SIEMENS	33691	MMCF/YR	Selective Catalytic Reduction System (SCR)	2	PPMVD	3-HR ROLLING AVE BASED ON 1-HR BLOCK AVE
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	Selective Catalytic Reduction Systems(SCR) and Dry Low NOx	2	PPMVD@15%O2	3-HR BLOCK AVERAGE BASED ON 1-HR BLOCK
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITHOUT DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	Selective Catalytic Reduction System (SCR) and Dry Low NOx	2	PPMVD@15%O2	3-HR ROLLING AVERAE BASED ON 1-HR BLOCK
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	Mitsubishi M501-GAC combustion turbine, combined cycle configuration with duct burner.	2988	MMBTU/H	Utilize dry low-NOx burners when combusting natural gas; Utilize water injection when combusting ULSD; Utilize selective catalytic reduction (SCR) with aqueous ammonia injection at all times except during startup and shutdown; Limit the time in startup or shutdown.	2	PPMDV AT 15% O2	3-HR ROLLING AVERAGE ON NG
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	GE LMS-100 combustion turbines, simple cycle with water injection	1690	MMBTU/H	Utilize water injection when combusting natural gas or ULSD; Utilize selective catalytic reduction (SCR) with aqueous ammonia injection at all times except during startup and shutdown; Limit the time in startup or shutdown.	2.5	PPMDV AT 15% O2	3-HR ROLLING AVERAGE ON NG
*PA-0298	FUTURE POWER PA/GOOD SPRINGS NGCC FACILITY	PA	3/4/2014	Turbine, COMBINED CYCLE UNIT (Siemens 5000)	2267	MMBTU/H	SCR	2	PPMVD	@ 15% OXYGEN

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PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Combustion Turbine with Duct Burner	2449	MMBTU/H	Dry Low NOx Combustors & Selective Catalytic Reduction	2	PPMVD @ 15% O2	1 HR BLOCK AVG/DO NOT APPLY DURING SS
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Turbine, Combined Cycle, #1 and #2	3046	MMBTU/H	SCR			
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: 2 Combined cycle CTGs with HRSGs with duct burners	647	MMBTU/H for each	SCR with DLNB (selective catalytic reduction with dry low NOx burners).	3	PPM	24-H ROLL.AVG. NOT STARTUP/SHUTDOWN
TX-0641	PINECREST ENERGY CENTER	TX	11/12/2013	combined cycle turbine	700	MW	selective catalytic reduction	2	PPMVD	24-HR ROLLING AVG, 15% OXYGEN
OH-0360	CARROLL COUNTY ENERGY	OH	11/5/2013	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	2045	MMBTU/H	selective catalytic reduction (SCR) and dry low NOx combustors	2	PPM	BY VOLUME AT 15% O2
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG1-4 Natural gas fueled combined cycle combustion turbine generators (CTG)	2147	MMBTU/H	Dry Low NOx burners (DLN) and Selective Catalytic Reduction (SCR) system.	2	PPMVOL	3-H ROLL AVG., EXCEPT STARTUP/SHUTDOWN
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG/DB1-4 Natural gas fueled combined cycle combustion turbine generators; duct burner on HRSG	2807	MMBTU/H	Dry low NOx burner (DLN) and selective catalytic reduction system (SCR).	2	PPMVOL	3-H ROLL AVG., EXCEPT STARTUP/SHUTDOWN
LA-0308	MORGAN CITY POWER PLANT	LA	9/26/2013	Combustion Turbine with SCR/HRSG	607.1	MMBTU/hr	Selective Catalytic Reduction (SCR) and Water/Steam Injection	5	PPM@15% O2	12 MONTH AVERAGE
TX-0709	SAND HILL ENERGY CENTER	TX	9/13/2013	Natural gas-fired combined cycle turbines	173.9	MW	SCR	2	PPM	24HR ROLLING AVG.
TX-0698	BAYPORT COMPLEX	TX	9/5/2013	(4) cogeneration turbines	90	MW	DLN and Closed Loop Emissions Controls (CLEC)	5	PPMVD	@15% O2, 3-HR ROLLING AVERAGE
NY-0104	CPV VALLEY ENERGY CENTER	NY	8/1/2013	Turbines and duct burners - NG			Dry low NOx combustion technology and selective catalytic reduction.	2	PPMVD @ 15% O2	1 H
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FGCCA or FGCCB--4 nat. gas fired CTG w/ DB for HRSG	2587	MMBTU/H heat inpu	Low NOx burners and selective catalytic reduction.	3	PPMV	24-H ROLLING AVERAGE
OK-0154	MOORELAND GENERATING STA	OK	7/2/2013	Combustion Turbine	360	MW	Dry Low-NOx burners with SCR.	2	PPMVD@15% O2	ONE-HR
OK-0154	MOORELAND GENERATING STA	OK	7/2/2013	COMBUSTION TURBINE	360	MW	DRY LOW-NOx BURNER WITH SCR.	2	PPMVD@15% O2	ONE-HR
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, without duct burners	515600	MMSCF/rolling 12-m	selective catalytic reduction (SCR); dry low NOx combustors; lean fuel technology	2	PPM	PPMVD AT 15% O2

TABLE A-1: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, with duct burners	51560	MMSCF/rolling 12-M	selective catalytic reduction (SCR); dry low NOx combustors; lean fuel technology	2	PPM	PPMVD AT 15% O2
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, without duct burners	47917	MMSCF/rolling 12-M	selective catalytic reduction (SCR); dry low NOx combustors; lean fuel technology	2	PPM	PPMVD AT 15% O2
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, with duct burners	47917	MMSCF/rolling 12-M	selective catalytic reduction (SCR); dry low NOx combustors; lean fuel technology	2	PPM	PPMVD AT 15% O2
VA-0322	GREEN ENERGY PARTNERS/ STONEWALL, LLC	VA	4/30/2013	Large combustion turbines (>25MW) CCT1 and CCT2	2.23	MMBTU/H	Selective Catalytic Reduction (SCR), with ammonia injection and dry low NOx combusion.			
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG	2237	MMBTU/H	Dry low NOx (DLN) burner and selective catalytic reduction (SCR) system.	2	PPM	EACH CTG; 24-H ROLLING AVG.
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG and duct burner (DB)	2486	MMBTU/H	Dry low NOx (DLN) burners and selective catalytic reduction (SCR) system.	2	PPM	24-H ROLLING AVG
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	COMBINED CYCLE UNITS #1 and #2	3.4	MMCF/HR	SCR	2	PPMVD @ 15% O2	WITH OR WITHOUT DUCT BURNER
PA-0288	SUNBURY GENERATION LP/SUNBURY SES	PA	4/1/2013	Combined Cycle Combustion Turbine AND DUCT BURNER (3)	2538000	MMBTU/H	SCR	2	PPM	CORRECTED TO 15% OXYGEN
VA-0321	BRUNSWICK COUNTY POWER STATION	VA	3/12/2013	COMBUSTION TURBINE GENERATORS, (3)	3442	MMBTU/H	Selective catalytic reduction and ultra low NOx burners.	2	PPMVD @ 15% O2	1 H AVG
TX-0708	LA PALOMA ENERGY CENTER	TX	2/7/2013	(2) combined cycle turbines	650	MW	Selective Catalytic Reduction	2	PPMVD	@15% O2, 24-HR ROLLING AVERAGE
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	Combined Cycle Power Blocks 472 MW - (2)			SCR	2	PPMDV	
DE-0024	GARRISON ENERGY CENTER	DE	1/30/2013	Unit 1	2260	million BTUs	Low NOx Combustors, Selective Catalytic Reduction	2	PPM	HOURLY AS BASELOAD ON NAT. GAS
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	OH	12/18/2012	Turbines (4) (model GE 7FA) Duct Burners Off	172	MW	Dry Low NOx burners and Selective Catalytic Reduction	3	PPM	PPMVD AT 15% O2 ON 3-H BLOCK AVERAGE
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	OH	12/18/2012	Turbines (4) (model GE 7FA) Duct Burners On	172	MW	Dry Low NOx burners and Selective Catalytic Reduction	3	PPM	PPMVD AT 15% O2 ON 3-H BLOCK AVERAGE
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES	2300	MMBTU/H	SELECTIVE CATALYTIC REDUCTION AND DRY LOW NOX BURNERS	2	PPMVD	3 HOURS
TX-0632	DEER PARK ENERGY CENTER LLC	TX	11/29/2012	CTG5/HRSG5(FD3-Series)						

TABLE A-1: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
TX-0632	DEER PARK ENERGY CENTER LLC	TX	11/29/2012	CTG5/ HRSG5 (FD2- Series)						
TX-0633	CHANNEL ENERGY ENERGY CENTER, LLC	TX	11/29/2012	CTG3/HRSG3(FD2-Series) -Initial Phase						
TX-0633	CHANNEL ENERGY ENERGY CENTER, LLC	TX	11/29/2012	CTG3/HRSG3(FD3-Series) -Final Phase						
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined cylce turbine with duct burner	39463	mmcubic ft/year*	Selelctive catalytic reduction (SCR) system	2	PPMVD	3-HR ROLLING AVERAGE BASED ON 1-HR BLOCK
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined Cycle Combustion Turbine	39463	MMCubic ft/yr	Selective Catalytic Reduction (SCR) System and use of natural gas a clean burning fuel	2	PPMVD	3-HR ROLLING AVE BASED ON 1-HR BLOCK AVE
DE-0023	NRG ENERGY CENTER DOVER	DE	10/31/2012	UNIT 2- KD1	655	MMBTU/H	Selective Catalytic Reduction	2.5	PPM	@ 15% OXYGEN BASED ON A 1 HOUR AVERAGE
TX-0618	CHANNEL ENERGY CENTER LLC	TX	10/15/2012	Combined Cycle Turbine	180	MW	Selective catalytic reduction	2	PPMVD	@15% O2 ON A 3-HR ROLLING AVG
FL-0337	POLK POWER STATION	FL	10/14/2012	Combine cycle power block (4 on 1)	1160	MW	SCR/DLN	2	PPMVD @15% O2	24-HR BLOCK (GAS) CEMS
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	Combined-cycle Turbines (2) - Natural gas fired	3277	MMBTU/H	Dry low-NOx (DLN) combustor and selective catalytic reduction (SCR)	2	PPMVD	
TX-0619	DEER PARK ENERGY CENTER	TX	9/26/2012	Combined Cycle Turbine	180	MW	Selective Catalytic Reduction	2	PPMVD	@15% O2, 3-HR ROLLING AVG
TX-0620	ES JOSLIN POWER PLANT	TX	9/12/2012	Combined cycle gas turbine	195	MW	Selective catalytic reduction	2	PPMVD	@15% O2, 24-HR ROLLING AVG
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Combined Cycle Turbine (EP01)	40	MW	SCR	3	PPMV AT 15% O2	1-HOUR
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Combined Cycle Turbine (EP02)	40	MW	SCR	3	PPMV AT 15% O2	1-HOUR
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Combined Cycle Combustion Turbine with Duct Burner	40297.6	mmcubic ft/year	Low NOx burners and Selective Catalytic Reduction System	2	PPMVD	3 HR ROLLING AVE BASED ON 1-HR BLOCK AVE
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Combined Cycle Combustion Turbine w/o duct burner	40297.6	mmcubic ft/year	DLN combustion system with SCR on each of the two combustion turbines and use of only natural gas as fuel.	2	PPMVD	3-HR ROLLING AVE BASED ON 1-HR BLOCK

TABLE A-2: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.110 (SIMPLE CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
*AK-0088	LIQUEFACTION PLANT	AK	7/7/2022	Six Simple Cycle Gas-Fired Turbines	1113	MMBtu/hr	SCR, DLN combustors, and good combustion practices	2	PPMV @ 15% O2	3-HOURS
AL-0329	COLBERT COMBUSTION TURBINE PLANT	AL	9/21/2021	Three 229 MW Simple Cycle Combustion Turbines	229	MW		9	PPMVD	3 HOUR AVG @ 15% O2
TX-0908	NEWMAN POWER STATION	TX	8/27/2021	Simple Cycle Turbine	230	MW	Dry Low NOx Burners and SCR	2.5	PPMVD	
MI-0447	LBWL--ERICKSON STATION	MI	1/7/2021	EUCTGSC1-natural gas fired simple cycle CTG	667	MMBTU/H	DLNB and good combustion practices.	25	PPM	4-HR ROLL AVG EXCEPT LESS THAN 75% PEAK
TX-0900	ECTOR COUNTY ENERGY CENTER	TX	8/17/2020	Simple Cycle Turbines			Equipped with dry-low NOx burners with best management practices and good combustion practices. Minimize the duration of startup and shutdown events to less than 60 minutes per event. Limit MSS by 140 lb/hr maximum allowable emission rate for each turbine.	9	PPMVD	3% O2 3 HR AVG
AK-0085	GAS TREATMENT PLANT	AK	8/13/2020	Six (6) Simple Cycle Gas-Turbines (Power Generation)	386	MMBtu/hr	DLN combustors and Good Combustion Practices	15	PPMV @ 15% O2	3-HOUR AVERAGE
MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUCTGSC1-A nominally rated 667 MMBTU/hr natural gas-fired simple cycle CTG	667	MMBTU/H	Dry low NOx burners (DLNB) and good combustion practices.	25	PPM	AT 15%O2;4-HR ROLL AVG; SEE NOTES BELOW
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Aeroderivative Simple Cycle Combustion Turbine	263	MM BTU/h	Selective Catalytic Reduction (SCR), exclusive combustion of fuel gas, and good combustion practices.	25	PPMV	30 DAY ROLLING AVERAGE
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	927	MM BTU/h	Dry Low NOx Combustor Design, Good Combustion Practices, and Natural Gas Combustion.	9	PPMV	30 DAY ROLLING AVERAGE
*LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG01 CO - Simple-Cycle Combustion Turbine 1 (Commissioning) [SCN0005]	2201	MM BTU/hr	Pipeline quality natural gas & dry-low-NOX burners	30	PPMVD @ 15% O2	
*LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG02 CO - Simple-Cycle Combustion Turbine 2 (Commissioning) [SCN0006]	2201	MM BTU/hr	Pipeline quality natural gas & dry-low-NOX burners	30	PPMVD @ 15% O2	
*LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG01 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	2201	MM BTU/hr	Pipeline quality natural gas & dry-low-NOX burners	9	PPMVD @15%O2	30-DAY ROLLING AVERAGE
*LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG02 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	2201	MM BTU/hr	Pipeline quality natural gas & dry-low-NOX burners	9	PPMVD @15%O2	30-DAY ROLLING AVERAGE
WV-0028	WAVERLY POWER PLANT	WV	3/13/2018	GE 7FA.004 Turbine	167.8	MW	Dry LNB	9	PPM	
TX-0833	JACKSON COUNTY GENERATORS	TX	1/26/2018	Combustion Turbines (normal operation)	920	MW	Dry low NOx burners	9	PPMVD	
TX-0826	MUSTANG STATION	TX	8/16/2017	Simple Cycle Turbine	162.8	MW	Dry low-NOx burners	9	PPMVD	
TX-0819	GAINES COUNTY POWER PLANT	TX	4/28/2017	Simple Cycle Turbine	227.5	MW	Dry Low NOx burners (control), natural gas, good combustion practices, limited operating hours (prevention)	9	PPMV	15% O2 3-H AVG

TABLE A-2: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.110 (SIMPLE CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
IN-0261	VERMILLION GENERATING STATION	IN	2/28/2017	SIMPLE CYCLE, NATURAL GAS FIRED COMBUSTION TURBINES	80	MW	GOOD COMBUSTION PRACTICES			
WV-0026	WAVERLY FACILITY	WV	1/23/2017	GE Model 7FA Turbine	1571	mmbtu/hr	Dry Low-NOx Combustion System (DLNB), Water Injection	9	PPM	NATURAL GAS
IN-0264	MONTPELIER GENERATING STATION	IN	1/6/2017	PRATT & WHITNEY TWIN-PAC SIMPLE CYCLE TURBINES	270.9	MMBTU/H	WATER INJECTION	25	PPMV	AT 15% O2 FOR NATURAL GAS
CA-1238	PUENTE POWER	CA	10/13/2016	Gas turbine	262	MW		2.5	PPMVD	1 HOUR@15%O2
VA-0326	DOSWELL ENERGY CENTER	VA	10/4/2016	Two (2) GE 7FA simple cycle combustion turbines	1961	MMBTU/HR	Low NOx Burners/Combustion Technology	9	PPM	VD/12 MO ROLLING TOTAL
IL-0121	INVENERGY NELSON EXPANSION LLC	IL	9/27/2016	Two Simple Cycle Combustion Turbines	190	MW	Dry low-NOx combustion technology for natural gas and low-NOx combustion technology and water injection for ULSD.	9	PPMVD @ 15% O2	
NJ-0086	BAYONNNE ENERGY CENTER	NJ	8/26/2016	Simple Cycle Stationary Turbines firing Natural gas	2143980	MMBTU/YR	Selective Catalytic Reduction, water injection, use of natural gas a low NOx emitting fuel	2.5	PPMVD@15%O2	3 H ROLLING AV BASED ON ONE H BLOCK AV
TX-0794	HILL COUNTY GENERATING FACILITY	TX	4/7/2016	Simple cycle turbine	171	MW	Emission controls consist of dry low-NOx combustors (DLN). DLN combustors use two stages of combustion, transitioning from initial startup with fuel and flame in the primary nozzles only, through a lean lean stage with fuel and flame in the primary and secondary nozzles, to fuel in the secondary stage only, extinguishing the primary flame, and in full operation, premix mode, with fuel to both nozzles, but flame only in the second stage. When natural gas and air are well-mixed before combustion, the flame temperature and resulting NOx emissions are greatly reduced compared to conventional diffusion flame combustion.	9	PPMVD @ 15% O2	3-HR ROLLING AVERAGE
TX-0788	NECHES STATION	TX	3/24/2016	Four Large Combustion Turbines >25 MW	232	MW	Dry low-NOx burners (DLN), good combustion practices	9	PPM	
TX-0790	PORT ARTHUR LNG EXPORT TERMINAL	TX	2/17/2016	Simple Cycle Electrical Generation Gas Turbines 15.210	34	MW	SELECTIVE CATALYTIC REDUCTION	5	PPM	ROLLING 24-HR AVERAGE
TX-0777	UNION VALLEY ENERGY CENTER	TX	12/9/2015	Simple Cycle Turbine	183	MW	dry low NOX burners	9	PPMVD @ 15% O2	3-HR ROLLING AVERAGE PEAK
TX-0769	VAN ALSTYNE ENERGY CENTER (VAEC)	TX	10/27/2015	Simple Cycle Turbine	183	MW	DLN burners	9	PPMVD @ 15% O2	3-HR AVERAGE
TX-0764	NACOGDOCHES POWER ELECTRIC GENERATING PLANT	TX	10/14/2015	Natural Gas Simple Cycle Turbine (>25 MW)	232	MW	Dry Low NOx burners, good combustion practices, limited operations	9	PPMVD @ 15% O2	
TX-0768	SHAWNEE ENERGY CENTER	TX	10/9/2015	Simple cycle turbines greater than 25 megawatts (MW)	230	MW	Dry Low NOx burners	9	PPMVD @ 15% O2	

TABLE A-2: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.110 (SIMPLE CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
FL-0355	FORT MYERS PLANT	FL	9/10/2015	Combustion Turbines	2262.4	MMBtu/hr gas	DLN and wet injection (for ULSD operation)	9	PPMVD@15% O2	GAS FIRING, 24-HR BLOCK AVG
TX-0733	ANTELOPE ELK ENERGY CENTER	TX	5/12/2015	Simple Cycle Turbine & Generator	202	MW	Dry Low NOx burners	9	PPMVD AT 15% O2	
TX-0734	CLEAR SPRINGS ENERGY CENTER (CSEC)	TX	5/8/2015	Simple Cycle Turbine	183	MW	dry low-NOx (DLN) burners	9	PPMVD @ 15% O2	3-HR AVERAGE
TX-0694	INDECK WHARTON ENERGY CENTER	TX	2/2/2015	(3) combustion turbines	220	MW	DLN combustors	9	PPMVD	@15% O2, 3-HR ROLLING AVERAGE
TX-0688	SR BERTRON ELECTRIC GENERATION STATION	TX	12/19/2014	Simple cycle natural gas turbines	225	MW	DLN	9	PPM	3HR ROLLING AVG.
TX-0696	ROAN'S PRAIRIE GENERATING STATION	TX	9/22/2014	(2) simple cycle turbines	600	MW	DLN combustors	9	PPMVD	@15% O2, 3-HR ROLLING AVG
TX-0695	ECTOR COUNTY ENERGY CENTER	TX	8/1/2014	(2) combustion turbines	180	MW	DLN combustors	9	PPMVD	@15% O2, 3-HR ROLLING AVG
MD-0043	PERRYMAN GENERATING STATION	MD	7/1/2014	(2) 60-MW SIMPLE CYCLE COMBUSTION TURBINES, FIRING NATURAL GAS	120	MW	USE OF NATURAL GAS, WATER/STEAM INJECTION, AND A SELECTIVE CATAYTIC REDUCTION (SCR) SYSTEM	2.5	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	TWO (2) NATURAL GAS FIRED COMBUSTION TURBINES	283	MMBTU/H, EACH	DRY LOW NOX COMBUSTORS	22.65	PPMVD AT 15% OXYGEN	3-HR AVERAGE AT >50% PEAK LOAD
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	TWO (2) NATURAL GAS FIRED COMBUSTION TURBINES	283	MMBTU/H, EACH	DRY LOW NOX COMBUSTORS	22.65	PPMVD AT 15% OXYGEN	3-HR AVERAGE AT >50% PEAK LOAD
TX-0691	PH ROBINSON ELECTRIC GENERATING STATION	TX	5/20/2014	(6) simple cycle turbines	65	MW	DLN combustors	15	PPMVD	@15% O2, 3-HR ROLLING AVERAGE
TX-0686	ANTELOPE ELK ENERGY CENTER	TX	4/22/2014	Combustion Turbine-Generator (CTG)	202	MW	DLN	9	PPM	15% O2, 3 HR. ROLLING AVG.
TX-0693	ANTELOPE ELK ENERGY CENTER	TX	4/22/2014	combustion turbine	202	MW	DLN combustors	9	PPMVD	@15% O2, 3-HR ROLLING AVERAGE
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	GE LMS-100 combustion turbines, simple cycle with water injection	1690	MMBTU/H	Utilize water injection when combusting natural gas or ULSD; Utilize selective catalytic reduction (SCR) with aqueous ammonia injection at all times except during startup and shutdown; Limit the time in startup or shutdown.	2.5	PPMDV AT 15% O2	3-HR ROLLING AVERAGE ON NG

TABLE A-2: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.110 (SIMPLE CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
ND-0030	LONESOME CREEK GENERATING STATION	ND	9/16/2013	Natural Gas Fired Simple Cycle Turbines	412	MMBTU/H	SCR	5	PPMVD	4 HOUR ROLLING AVERAGE EXCEPT STARTUP
ND-0029	PIONEER GENERATING STATION	ND	5/14/2013	Natural gas-fired turbines	451	MMBTU/H	Water injection plus SCR	5	PPPMVD	4 HR. ROLLING AVERAGE EXCEPT FOR STARTUP
TX-0701	ECTOR COUNTY ENERGY CENTER	TX	5/13/2013	Simple Cycle Combustion Turbines	180	MW	Dry low NOx combustor	9	PPMVD	15%O2, 3HR ROLLING BASIS
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	GE LM6000PC SPRINT Simple cycle combustion turbine	405.3	MMBTU/hr	water injection	25	PPMDV	24-HR ROLLING AVE; CORRECTED TO 15% O
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	GE LM6000PC SPRINT Simple cycle combustion turbine	405.3	MMBTU/hr	dry low NOx burners and fire only pipeline natural gas	9	PPMDV	24-HR ROLLING AVE, CORRECTED TO 15% O2
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	GE 7FA Simple Cycle Combustion Turbine	1780	MMBTU/HR	dry low NOx burners and fire only pipeline natural gas	9	PPMDV	24-HR ROLLING AVE, CORRECTED TO 15% O2
ND-0028	R.M. HESKETT STATION	ND	2/22/2013	Combustion Turbine	986	MMBTU/H	Dry low-NOx combustion (DLN)	9	PPMVD @15% OYYGEN	4 H.R.A. WHEN > 50MWE AND > 0 DEGREES F
CA-1223	PIO PICO ENERGY CENTER	CA	11/19/2012	COMBUSTION TURBINES (NORMAL OPERATION)	300	MW	WATER INJECTION, SCR	2.5	PPMVD	@15% O2, 1-HR AVG
TX-0690	CEDAR BAYOU ELECTRIC GERNERATION STATION	TX	9/12/2012	Simple Cycle Combustion Turbines	225	MW	DLN	9	PPM	3HR. ROLLING AVG.
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Simple Cycle Turbine (EP03)	40	MW	SCR	5	PPMV AT 15% O2	1-HOUR
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Simple Cycle Trubine (EP04)	40	MW	SCR	5	PPMV AT 15% O2	1-HOUR AVERAGE
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Simple Cycle Turbine (EP05)	40	MW	SCR	5	PPMV AT 15% O2	1-HOUR
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FG-PEAKERS: 2 natural gas fired simple cycle combustion turbines	171	MMBTU/H	Dry low-NOx combustors	24	PPMVD @ 15% O2	

TABLE A-3: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
*AK-0088	LIQUEFACTION PLANT	AK	7/7/2022	Four Combined Cycle Gas-Fired Turbines	384	MMBtu/hr	Oxidation catalyst and good combustion practices	2	PPMV @ 15% O2	3-HOURS
*WV-0033	MAIDSVILLE	WV	1/5/2022	Combustion Turbine & Duct Burner (CT-01/HRSG1 &; CT-02/HRSG2)	1275	mw	good combustion practices and oxidation catalyst	1	PPMDV @ 15% O2	AVG OF 3 1-HR TEST RUNS (W/O DUCT FIRING
*WV-0033	MAIDSVILLE	WV	1/5/2022	Combustion Turbine & Duct Burner (CT-01/HRSG1 &; CT-02/HRSG2)	1275	mw	good combustion practices and oxidation catalyst	1	PPMDV @ 15% O2	AVG OF 3 1-HR TEST RUNS (W/O DUCT FIRING
TX-0915	UNIT 5	TX	3/17/2021	COMBINED CYCLE TURBINE			OXIDATION CATALYST	1	PPMVD	3-HR ROLLING
MI-0447	LBWL--ERICKSON STATION	MI	1/7/2021	EUCTGHRSG1	667	MMBTU/H	An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices.	3	PPM	HOURLY EXCEPT STARTUP SHUTDOWN
MI-0447	LBWL--ERICKSON STATION	MI	1/7/2021	EUCTGHRSG2	667	MMBTU/H	An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices.	3	PPM	HOURLY; EXCEPT DURING STARTUP/SHUTDOWN
AL-0328	PLANT BARRY	AL	11/9/2020	Two 744 MW Combined Cycle Units	744	MW	Oxidation Catalyst	2	PPMDV @ 15% O2 as CH4	
*WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Natural-Gas-Fired Combined-Cycle Turbine (P01)	4671	MMBTU/H	Oxidation Catalyst, good combustion control	2.7	PPM AT 15% O2	168-HR AVG., NAT. GAS, DUCT FIRING
LA-0364	FG LA COMPLEX	LA	1/6/2020	Cogeneration Units	2222	mm btu/h	Good combustion practices and catalytic oxidation	4	PPMVD	
*MI-0445	INDECK NILES, LLC	MI	11/26/2019	FGCTGHRSG	3421	MMBTU/H	Good combustion practices, inlet air conditioning, and the use of pipeline quality natural gas.	4	PPM	PPMVD@15%O2, HOURLY; EACH
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	MI	8/21/2019	FGCTGHRSG	625	MW	Oxidation catalyst and good combustion practices.	3	PPMDV @ 15% O2 as CH4	
NJ-0088	COGEN TECH LINDEN VENTURE LP	NJ	7/30/2019	250 MW COMBINED CYCLE COMBUSTION TURBINE FIRING NATURAL GAS	21042	MMCubic ft/yr	Add on Oxidation Catalyst and use of Natural Gas as primary fuel for pollution prevention	1	PPMVD@15% O2	3 H ROLLING AV BASED ON ONE H BLOCK
VA-0332	CHICKAHOMINY POWER LLC	VA	6/24/2019	Three (3) Mitsubishi Hitachi Power Systems combustion turbine generators	35000	MMCF/YR	Controlled by an oxidation catalyst and good combustion practices (e.g. controlled fuel/air mixing, adequate temperature, and gas residence time)	0.7	PPMVD @ 15% O2	3 HR AVG
MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUCTGHRSG2--A 667 MMBTU/H natural gas fired CTG with a HRSG.	667	MMBTU/H	An oxidation catalyst for VOC control and good combustion practices.	3	PPM	PPMVD@15%O2; HOURLY; SEE NOTES

TABLE A-3: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUCTGHRSG1--A 667 MMBTU/H NG fired combustion turbine generator coupled with a heat recovery steam generator (HRSG)	667	MMBTU/H	An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices.	3	PPM	PPMVD@15%O2; HOURLY EXC.START/SHUT; NOTE
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Combined Cycle Combustion Turbines (CCCT1 to CCCT5)	921	MM BTU/h	Catalytic Oxidation, Proper Equipment Design and Good Combustion Practices.	1.1	PPMV	3 HOUR AVERAGE
*WV-0032	BROOKE COUNTY POWER PLANT	WV	9/18/2018	GE 7HA.01 Turbine	2737.7	mmBtu/hr	Oxidation Catalyst, Good Combustion Practices	2	PPMDV @ 15% O2 as CH4	
*PA-0319	RENAISSANCE ENERGY CENTER	PA	8/27/2018	COMBUSTION TURBINE UNIT w/o DUCT BURNERS UNIT	2665.9	MMBtu/hr	Oxidation Catalyst	1	PPMDV	@15% O2
*PA-0319	RENAISSANCE ENERGY CENTER	PA	8/27/2018	COMBUSTION TURBINE UNIT with DUCT BURNERS UNIT				1.4	PPMDV	@15% O2
MI-0432	NEW COVERT GENERATING FACILITY	MI	7/30/2018	FG-TURB/DB1-3 (3 combined cycle combustion turbine and heat recovery steam generator trains)	1230	MW	An oxidation catalyst and good combustion practices.	1	PPMVD	HOURLY; EACH CT/HRSG TRAIN
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	FGCTGHRSG (EUCTGHRSG1 & EUCTGHRSG2)			Oxidation catalyst technology and good combustion practices.	2	PPMDV @ 15% O2 as CH4	
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUCTGHRSG (South Plant): A combined cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	500	MW	Oxidation catalyst technology and good combustion practices.	4	PPMVD	AT 15%O2; NOT INCL. STARTUP/SHUTDOWN
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUCTGHRSG (North Plant): A combined-cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	500	MW	Oxidation catalyst technology and good combustion practices.	4	PPMVD	AT 15%O2; HOURLY
VA-0328	C4GT, LLC	VA	4/26/2018	GE Combustion Turbine - Option 1 - Normal Operation	34000	MMCF/YR	Oxidation catalyst and good combustion practices	0.7	PPMVD @ 15% O2	3 HR AV/WITHOUT DB
VA-0328	C4GT, LLC	VA	4/26/2018	Siemens Combusion Turbine - Option 2 - Normal Operation	35000	MMCF/YR	Oxidation catalyst and good combustion practice	1	PPMVD @ 15% O2	3 H AV/WITHOUT DB
OH-0377	HARRISON POWER	OH	4/19/2018	General Electric (GE) Combustion Turbines (P005 & P006)	3459.6	MMBTU/H	Good combustion practices and oxidation catalyst	1	PPMDV @ 15% O2 as CH4	
OH-0377	HARRISON POWER	OH	4/19/2018	Mitsubishi Hitachi Power Systems (MHPS) Combustion Turbines (P007 & P008)	3231	MMBTU/H	Good combustion practices and oxidation catalyst	2	PPMDV @ 15% O2 as CH4	
TX-0834	MONTGOMERY COUNTY POWER STATIOIN	TX	3/30/2018	Combined Cycle Turbine	2635	MMBTU/HR/UNIT	Oxidation catalyst	2	PPMVD	15% O2 3 HOUR AVERAGE
*WV-0029	HARRISON COUNTY POWER PLANT	WV	3/27/2018	GE 7HA.02 Turbine	3496.2	mmBtu/hr	Oxidation Catalyst, Good Combustion Practices	3	PPMDV @ 15% O2 as CH4	

TABLE A-3: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
FL-0364	SEMINOLE GENERATING STATION	FL	3/21/2018	2-on-1 natural gas combined-cycle unit (GE 7HA.02)	3514	MMBtu/hr	Oxidation catalyst	1	PPMVD@15% O2	WITHOUT DUCT BURNER FIRING
*PA-0316	RENOVO ENERGY CENTER, LLC	PA	1/26/2018	Combustion Turbine Firing NG				1	PPMDV	CORRTECTED TO 15% O2
FL-0363	DANIA BEACH ENERGY CENTER	FL	12/4/2017	2-on-1 combined cycle unit (GE 7HA)	4000	MMBtu/hr	Clean fuels	1	PPMVD@15% O2	FOR NATURAL GAS OPERATION
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	11/7/2017	General Electric Combustion Turbine (P004)	3544	MMBTU/H	Oxidation catalyst and good combustion practices as recommended by the manufacturer.	1	PPMDV @ 15% O2 as CH4	
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	11/7/2017	Mitsubishi Combustion Turbine (P005)	3320	MMBTU/H	oxidation catalyst and shall operate the emissions unit in accordance with good combustion practices as recommended by the manufacturer	2	PPMDV @ 15% O2 as CH4	
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	11/7/2017	Siemens Combustion Turbine (P006)	3602	MMBTU/H	oxidation catalyst and shall operate the emissions unit in accordance with good combustion practices as recommended by the manufacturer	2	PPMDV @ 15% O2 as CH4	
OH-0374	GUERNSEY POWER STATION LLC	OH	10/23/2017	Combined Cycle Combustion Turbines (3, identical) (P001 to P003)	3516	MMBTU/H	oxidation catalyst and good combustion practices as recommended by the manufacturer	3	PPMDV @ 15% O2 as CH4	
OH-0372	OREGON ENERGY CENTER	OH	9/27/2017	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	3055	MMBTU/H	oxidation catalyst and good combustion control	2	PPMDV @ 15% O2 as CH4	
OH-0370	TRUMBULL ENERGY CENTER	OH	9/7/2017	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	3025	MMBTU/H	Good combustion controls and oxidation catalyst	2	PPMDV @ 15% O2 as CH4	
CT-0161	KILLINGLY ENERGY CENTER	CT	6/30/2017	Natural Gas w/o Duct Firing	2969	MMBtu/hr	Oxidation Catalyst	0.7	PPMVD @15% O2	
CT-0161	KILLINGLY ENERGY CENTER	CT	6/30/2017	Natural Gas w/Duct Firing	2639	MMBtu/hr	Oxidation Catalyst	1.6	PPMVD @15% O2	
TX-0819	GAINES COUNTY POWER PLANT	TX	4/28/2017	Combined Cycle Turbine with Heat Recovery Steam Generator, fired Duct Burners, and Steam Turbine Generator	426	MW	Oxidation catalyst and good combustion practices	3.5	PPMVD	15% O2
*PA-0315	HILLTOP ENERGY CENTER, LLC	PA	4/12/2017	Combustion Turbine without Duct Burner	3509	MMBtu/hr		1	PPMDV	CORRECTED TO 15% O2
*PA-0315	HILLTOP ENERGY CENTER, LLC	PA	4/12/2017	Combustion Turbine With Duct Burner	4367	MMBtu/hr		2	PPMDV	CORRECTED TO 15% O2
TX-0817	CHOCOLATE BAYOU STEAM GENERATING (CBSG) STATION	TX	2/17/2017	Combined Cycle Cogeneration	50	MW	OXIDATION CATALYST	1	PPMDV	
MI-0423	INDECK NILES, LLC	MI	1/4/2017	FGCTGHRSG (2 Combined Cycle CTGs with HRSGs)	8322	MMBTU/H	Oxidation Catalyst Technology and Good Combustion Practices	4	PPM	TEST PROTOCOL WILL SPECIFY

TABLE A-3: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	FGCTGHRSG (2 Combined cycle CTGs with HRSGs; EUCTGHRSG10 & EUCTGHRSG11)	554	MMBTU/H, each	Oxidation catalyst technology and good combustion practices.	4	PPM AT 15% O2	TEST PROTOCOL WILL SPECIFY AVG TIME
OH-0367	SOUTH FIELD ENERGY LLC	OH	9/23/2016	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	3131	MMBTU/H	Good combustion controls and oxidation catalyst	3	PPMDV @ 15% O2 as CH4	
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Combustion turbine and HRSG with duct burner NG only	3338	MMBtu/hr	Oxidation catalyst and good combustion practices	1.5	PPMDV @ 15% O2	
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Combustion turbine and HRSG without duct burner NG only				1	PPMDV @ 15% O2	
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Combined Cycle Unit 1A	3625	MMBTU/hr	Catalytic oxidation and good combustion practices for normal operations, and good combustion practices for startup/shutdown operations.	13	PPMDV @ 15% O2 as CH4	
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Combined Cycle Unit 1B	3625	MMBTU/hr	Catalytic oxidation and good combustion practices during normal operations, and good combustion practices during startup/shutdown operations.	13	PPMDV @ 15% O2 as CH4	
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas with Duct Burner	4000	h/yr	Oxidation Catalyst and good combustion practices	2	PPMVD@15%O2	AV OF THREE ONE H STACK TESTS EVERY 5 YR
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas without Duct Burner	8040	H/YR	Oxidation catalyst and good combustion practices	1	PPMVD@15%O2	AV OF THREE ONE H STACK TESTS EVERY 5 YR
VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	COMBUSTION TURBINE GENERATOR WITH DUCT-FIRED HEAT RECOVERY STEAM GENERATORS (3)	3227	MMBTU/HR	Oxidation Catalyst and good combustion practices	1.4	PPMVD	
TX-0788	NECHES STATION	TX	3/24/2016	Large Combustion Turbines >25 MW	232	MW	good combustion practices	2	PPM	
TX-0788	NECHES STATION	TX	3/24/2016	Combined Cycle & Cogeneration	231	MW	OXIDATION CATALYST	2	PPM	
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Combined Cycle Combustion Turbine with Duct Burner firing natural gas			Oxidation Catalyst and good combustion practices	2	PPMVD	3 H ROLLING AV BASED ON ONE H BLOCK
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Combined Cycle Combustion Turbine without Duct Burner Firing Natural Gas	28169501	MMBTU/YR	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1	PPMVD@15%O2	3 H ROLLING AV BASED ON ONE H BLOCK
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	Combined-cycle electric generating unit	3096	MMBtu/hr per turbi	Complete combustion minimizes VOC	1	PPMVD@15%O2	GAS OPERATION
TX-0789	DECORDOVA STEAM ELECTRIC STATION	TX	3/8/2016	Combined Cycle & Cogeneration	231	MW	OXIDATION CATALYST	2	PPM	

TABLE A-3: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
PA-0306	TENASKA PA PARTNERS/WESTMORELAND GEN FAC	PA	2/12/2016	Large Combustion turbine			Ox Cat and good combustion practices	1.4	PPMVD @ 15% O2	
PA-0306	TENASKA PA PARTNERS/WESTMORELAND GEN FAC	PA	2/12/2016	Large combustion turbine			Ox Cat and good combustion practices	2.4	PPMDV@15% O2	
NY-0103	CRICKET VALLEY ENERGY CENTER	NY	2/3/2016	Turbines and duct burners	228	mw	good combustion practices and oxidation catalyst	0.7	PPMVD @ 15% O2	1 H
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	Combustion turbine with duct burner	3304.3	MMBtu/hr	Oxidation catalyst, combustion controls, exclusive natural gas	1.5	PPMDV @ 15% O2	
CT-0157	CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/12 months	Oxidation Catalyst	1	PPMVD @15% O2	
CT-0158	CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/yr	Oxidation Catalyst	1	PPMVD @15% O2	
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES	286	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1	PPMVD @ 15% O2	3-HR BLOCK AVG. W/OUT DUCT FIRING
TX-0773	FGE EAGLE PINES PROJECT	TX	11/4/2015	Combined Cycle Turbines (>25 MW)	321	MW	Oxidation Catalyst	2	PPM	
TX-0767	LON C. HILL POWER STATION	TX	10/2/2015	Combined Cycle Turbines (>25 MW)	195	MW	oxidation catalyst	2	PPM	
PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Combustion Turbine With Duct Burner	3727	MMBtu/hr	Oxidation catalyst and good engineering practice	1.5	PPMDV @ 15% O2	
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	8/25/2015	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	2725	MMBTU/H	Good combustion controls and oxidation catalyst	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
PA-0305	SHELL CHEM APPALACHIA/PETROCHEMICALS COMPLEX	PA	6/18/2015	Combustion turbine wih duct burner and heat recovery steam generator	Three 40.6 MW turbines			1	PPMDV @ 15% O2	
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	TX	6/18/2015	Combined Cycle Turbines (>25 MW) natural gas	210	MW	Oxidation catalyst	2	PPM	
PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	PA	6/15/2015	Two combined cycle turbines with out duct burner	2291.64	MCF/hr	Oxidation catalyst, good combustion practices and low sulfur fuels	1.5	PPMDV @ 15% O2	
PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	PA	6/15/2015	Two Combine Cycle Combustion Turbine with Duct Burner	3001.57	MCF/hr	Oxidation catalyst, good combustion practices and low sulfur fuels	1.9	PPMDV @ 15% O2	
KY-0104	CASH CREEK GENERATING STATION	KY	6/10/2015	Combined cycle combustion turnbine with HRSG and duct firing	849	MW	burn Pipeline quality Natural Gas			

TABLE A-3: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
OH-0365	ROLLING HILLS GENERATING, LLC	OH	5/20/2015	Combustion Turbines, Scenario 1 (4, identical) (P001, P002, P004, P005)	2022	MMBTU/H	good combustion practices along with clean fuels	1.4	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
OH-0365	ROLLING HILLS GENERATING, LLC	OH	5/20/2015	Combustion Turbines, Scenario 2 (4, identical) (P001, P002, P004, P005)	2144	MMBTU/H	good combustion practices along with clean fuels	0.84	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
TX-0730	COLORADO BEND ENERGY CENTER	TX	4/1/2015	Combined-cycle gas turbine electric generating facility	1100	MW	SCR and oxidation catalyst	4	PPMVD @ 15% O2	3-HR AVERAGE
TX-0714	S R BERTRON ELECTRIC GENERATING STATION	TX	12/19/2014	(2) combined cycle turbines	240	MW	oxidation catalyst	1	PPMVD	@15% O2
TX-0710	VICTORIA POWER STATION	TX	12/1/2014	combined cycle turbine	197	MW	oxidation catalyst	4	PPMVD	@15% O2, 3-HR ROLLING AVERAGE
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Combined Cycle Turbine/Duct Burner	2419.61	mmBtu/Hr	Oxidation Catalyst & Good Combustion Practices	2	PPM	@ 15% O2
TX-0712	TRINIDAD GENERATING FACILITY	TX	11/20/2014	combined cycle turbine	497	MW	oxidation catalyst	4	PPMVD	@15% O2 1-HR
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	235	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1	PPMVD @ 15% O2	W/OUT DUCT FIRING, 3-HR BLOCK AVG
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine without Duct Burner	20282	MMCF/YR	Oxidation catalysts and use of Natural gas a clean burning fuel	0.7	PPMVD215%O2	AVERAGE OF THREE ONE HOUR STACK TESTS
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine with Duct Burner	20282	MMCF/YR	Oxidation catalyst and use of natural gas a clean burning fuel	1	PPMVD@15%O2	AVERAGE OF THREE STACK TEST RUNS
TX-0713	TENASKA BROWNSVILLE GENERATING STATION	TX	4/29/2014	(2) combined cycle turbines	274	MW	oxidation catalyst	2	PPMVD	@15% O2, 3-HR AVERAGE
MD-0041	CPV ST. CHARLES	MD	4/23/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	725	MEGAWATT	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD
MD-0041	CPV ST. CHARLES	MD	4/23/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITH DUCT FIRING	725	MW	EXCLUSIVE USE OF NATURAL GAS, AND AN OXIDATION CATALYST	2	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD

TABLE A-3: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	Combustion turbine #1 - combined cycle	2258	mmBtu/hr	catalytic oxidizer	1	PPM	AVG. OF 3 ONE HOUR TEST RUNS
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	Combustion turbine #2 -combined cycle	2258	mmBtu/hr		1	PPM	AVERAGE OF 3 ONE-HOUR TEST RUNS
MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITH DUCT FIRING	1000	MW	USE OF PIPELINE NATURAL GAS, GOOD COMBUSTION PRACTICES, AND USE OF AN OXIDATION CATALYST	1.6	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD
TX-0660	FGE TEXAS POWER I AND FGE TEXAS POWER II	TX	3/24/2014	Alstom Turbine	230.7	MW	Oxidation catalyst, good combustion practices	2	PPMVD	CORRECTED TO 15% O2, ROLLING 3 HR AVE
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	Combined Cycle Combustion Turbine - Siemens turbine without Duct Burner	33691	MMCF/YR	Good Combustion Practices and use of Natural gas as a clean burning fuel	1	PPMVD@ 15%O2	AVERAGE OF THREE TESTS
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - SIEMENS	33691	MMCF/YR	Oxidation catalyst and pollution prevention (use of natural gas a clean burning fuel)	2	PPMVD	AVERAGE OF THREE ONE HOUR TESTS
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	CO Oxidation Catalyst and good combustion practices and use natural gas only as a clean burning fuel	2	PPMVD@15%O2	AVERAGE OF THREE ONE HOUR TESTS
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITHOUT DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	Oxidation Catalyst and use of natural gas a clean burning fuel	1	PPMVD@15%O2	AVERAGE OF THREE ONE-HOUR TESTS
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	Mitsubishi M501-GAC combustion turbine, combined cycle configuration with duct burner.	2988	MMBTU/H	Oxidation catalyst; Limit the time in startup or shutdown.	2	PPMDV AT 15% O2	3-HR ROLLING AVERAGE ON NG
*PA-0298	FUTURE POWER PA/GOOD SPRINGS NGCC FACILITY	PA	3/4/2014	Turbine, COMBINED CYCLE UNIT (Siemens 5000)	2267	MMBTU/H	CO Catalyst	2	PPMVD	@ 15% OXYGEN
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Combustion Turbine with Duct Burner	2449	MMBTU/H	Oxidation catalyst	1	PPMVD@15% O2	1 HR AVG EXCLUDING SS/NO DUCT FIRING
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Turbine, Combined Cycle, #1 and #2	3046	MMBTU/H				

TABLE A-3: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: 2 Combined cycle CTGs with HRSGs with duct burners	647	MMBTU/H for each	Oxidation catalyst technology and good combustion practices.	4	PPM	TEST PROTOCOL
TX-0641	PINECREST ENERGY CENTER	TX	11/12/2013	combined cycle turbine	700	MW	oxidation catalyst	2	PPMVD	INITIAL STACK TEST, 15% OXYGEN
OH-0360	CARROLL COUNTY ENERGY	OH	11/5/2013	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	2045	MMBTU/H	oxidation catalyst	3	PPMDV @ 15% O2 as CH4	
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG1-4 Natural gas fueled combined cycle combustion turbine generators (CTG)	2147	MMBTU/H	Catalytic oxidation system (COS)	2	PPMVOL	DRY AT 15% OXYGEN
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG/DB1-4 Natural gas fueled combined cycle combustion turbine generators; duct burner on HRSG	2807	MMBTU/H	Catalytic oxidation system (COS)	2	PPMVOL	DRY AT 15% OXYGEN
TX-0709	SAND HILL ENERGY CENTER	TX	9/13/2013	Natural gas-fired combined cycle turbines	173.9	MW		2	PPM	1HR. AVG.
NY-0104	CPV VALLEY ENERGY CENTER	NY	8/1/2013	Turbines and duct burners - NG			Good combustion practice and oxidation catalyst.	0.7	PPMVD @ 15% O2	1 H
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FGCCA or FGCCB--4 nat. gas fired CTG w/ DB for HRSG	2587	MMBTU/H heat inp	Efficient combustion control plus catalytic oxidation system.			
OK-0154	MOORELAND GENERATING STA	OK	7/2/2013	Combustion Turbine	360	MW	Oxidation catalyst and good combustion practices.	5	PPMVD@15%O2	30-DAY
OK-0154	MOORELAND GENERATING STA	OK	7/2/2013	COMBUSTION TURBINE	360	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES.	5	PPMVD@15% O2	30-DAY
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, without duct burners	515600	MMSCF/rolling 12-n	oxidation catalyst	1	PPM	PPMVD AT 15% O2
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, with duct burners	51560	MMSCF/rolling 12-N	oxidation catalyst	1.9	PPM	PPMVD AT 15% O2
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, without duct burners	47917	MMSCF/rolling 12-N	oxidation catalyst	2	PPM	PPMVD AT 15% O2
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, with duct burners	47917	MMSCF/rolling 12-N	oxidation catalyst	2	PPM	PPMVD AT 15% O2
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG	2237	MMBTU/H	Good combustion practices	1	PPMDV @ 15% O2 as CH4	
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG and duct burner (DB)	2486	MMBTU/H	Good combustion practices	3	PPMDV @ 15% O2 as CH4	

TABLE A-3: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	COMBINED CYCLE UNITS #1 and #2	3.4	MMCF/HR	Oxidation Catalyst	1.5	PPMVD @ 15% OXYGEN	WITH OR WITHOUT DUCT BURNER
PA-0288	SUNBURY GENERATION LP/SUNBURY SES	PA	4/1/2013	Combined Cycle Combustion Turbine AND DUCT BURNER (3)	2538000	MMBTU/H	Oxidation Catalyst	1	PPM	3 LB/HR, DUCT BURN NOT OPERATING, 15% O2
VA-0321	BRUNSWICK COUNTY POWER STATION	VA	3/12/2013	COMBUSTION TURBINE GENERATORS, (3)	3442	MMBTU/H	Oxidation catalyst; good combustion practices.	0.7	PPMVD	3 H AVG/WITHOUT DUCT BURNING
TX-0708	LA PALOMA ENERGY CENTER	TX	2/7/2013	(2) combined cycle turbines	650	MW	oxidation catalyst	2	PPMVD	@15% O2, 3-HR ROLLING
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	Combined Cycle Power Blocks 472 MW - (2)			CO Catalyst	1	PPMDV	WITHOUT DUCT BURNER
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	OH	12/18/2012	Turbines (4) (model GE 7FA) Duct Burners Off	172	MW	Using efficient combustion technology			
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	OH	12/18/2012	Turbines (4) (model GE 7FA) Duct Burners On	172	MW	Using efficient combustion technology			
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES	2300	MMBTU/H	OXIDIZED CATALYST	1	PPMVD	3 HOURS
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined cylce turbine with duct burner	39463	mmcubic ft/year*	Oxidation catalyst	1	PPMVD	3-HR ROLLING AVERAGE BASED ON 1-HR BLOCK
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined Cycle Combustion Turbine	39463	MMCubic ft/yr	Oxidation Catalyst and Good combustion Practices and use of natural gas a clean burning fuel			
DE-0023	NRG ENERGY CENTER DOVER	DE	10/31/2012	UNIT 2- KD1	655	MMBTU/H	Oxidation catalyst system	8	PPMDV @ 15% O2 as CH4	
TX-0618	CHANNEL ENERGY CENTER LLC	TX	10/15/2012	Combined Cycle Turbine	180	MW	Good combustion	2	PPMVD	@15% O2
FL-0337	POLK POWER STATION	FL	10/14/2012	Combine cycle power block (4 on 1)	1160	MW	fuel Sulfur limits	1.4	PPMVD @15% O2	
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	Combined-cycle Turbines (2) - Natural gas fired	3277	MMBTU/H	Oxidation Catalyst	1	PPMVD	WITHOUT DUCT BURNER
TX-0619	DEER PARK ENERGY CENTER	TX	9/26/2012	Combined Cycle Turbine	180	MW	good combustion, use of natural gas	2	PPMVD	@15% O2
TX-0620	ES JOSLIN POWER PLANT	TX	9/12/2012	Combined cycle gas turbine	195	MW	good combustion and natural gas as fuel	2	PPMVD @15% O2	

TABLE A-3: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Combined Cycle Turbine (EP01)	40	MW	Oxidation Catalyst	3	PPMV AT 15% O2	1-HOUR
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Combined Cycle Turbine (EP02)	40	MW	Oxidation Catalyst	3	PPMV AT 15% O2	3-HOUR AVERAGE
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Combined Cycle Combustion Turbine with Duct Burner	40297.6	mmcubic ft/year	oxidation Catalyst and Good Combustion Practices and use of Clean fuel (Natural gas)	2	PPMVD	3-HR ROLLING AVERAGE BASED ON 1-HR BLK
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Combined Cycle Combustion Turbine w/o duct burner	40297.6	mmcubic ft/year	Oxidation catalyst and good combustion practices, use of natural gas a clean burning fuel	1	PPMVD	3H ROLLING AVE BASED ON 1H BLOCKS

TABLE A-4: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.110 (SIMPLE CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
*AK-0088	LIQUEFACTION PLANT	AK	7/7/2022	Six Simple Cycle Gas-Fired Turbines	1113	MMBtu/hr	Oxidation catalyst and good combustion practices	2	PPMV @ 15% O2	3-HOURS
TX-0908	NEWMAN POWER STATION	TX	8/27/2021	Simple Cycle Turbine	230	MW	Use of Natural gas, good combustion practices, and oxidation catalyst	2	PPMVD	
TX-0915	UNIT 5	TX	3/17/2021	SIMPLE CYCLE TURBINE	14552539	MMBTU/YR	Oxidation catalyst	1.5	PPMVD	3-HR ROLLING
MI-0447	LBWL--ERICKSON STATION	MI	1/7/2021	EUCTGSC1-natural gas fired simple cycle CTG	667	MMBTU/H	Good combustion practices	6	PPMDV @ 15% O2 as CH4	
MI-0447	LBWL--ERICKSON STATION	MI	1/7/2021	EUCTGHRSG1	667	MMBTU/H	An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices.	3	PPM	HOURLY EXCEPT STARTUP SHUTDOWN
MI-0447	LBWL--ERICKSON STATION	MI	1/7/2021	EUCTGHRSG2	667	MMBTU/H	An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices.	3	PPM	HOURLY; EXCEPT DURING STARTUP/SHUTDOWN
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	LA	9/3/2020	Turbines (EQT0020 - EQT0031)			Good combustion practices			
AK-0085	GAS TREATMENT PLANT	AK	8/13/2020	Six (6) Simple Cycle Gas-Turbines (Power Generation)	386	MMBtu/hr	Good Combustion Practices and burning clean fuels (NG)	2	PPMDV @ 15% O2 as CH4	
MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUCTGSC1-A nominally rated 667 MMBTU/hr natural gas-fired simple cycle CTG	667	MMBTU/H	Good combustion practices.	6	PPMDV @ 15% O2 as CH4	
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Aeroderivative Simple Cycle Combustion Turbine	263	MM BTU/h	Proper Equipment Design, Proper Operation, and Good Combustion Practices.	1.5	PPMV	3 HOUR AVERAGE
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	927	MM BTU/h	Proper Equipment Design, Proper Operation, and Good Combustion Practices.	1.4	PPMV	3 HOUR AVERAGE
*LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG01 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas			
*LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG02 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas			
TX-0833	JACKSON COUNTY GENERATORS	TX	1/26/2018	Combustion Turbines (normal operation)	920	MW	Good combustion practices	2	PPMVD	
TX-0819	GAINES COUNTY POWER PLANT	TX	4/28/2017	Simple Cycle Turbine	227.5	MW	Pipeline quality natural gas; limited hours; good combustion practices	2	PPMVD	
IN-0261	VERMILLION GENERATING STATION	IN	2/28/2017	SIMPLE CYCLE, NATURAL GAS FIRED COMBUSTION TURBINES	80	MW	GOOD COMBUSTION PRACTICES			

TABLE A-4: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.110 (SIMPLE CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
LA-0316	CAMERON LNG FACILITY	LA	2/17/2017	Gas turbines (9 units)	1069	mm btu/hr	good combustion practices and fueled by natural gas	1.6	PPMVD	@15%O2
CA-1238	PUENTE POWER	CA	10/13/2016	Gas turbine	262	MW		2	PPMVD AS METHANE	1 HOUR@15%O2
NJ-0086	BAYONNNE ENERGY CENTER	NJ	8/26/2016	Simple Cycle Stationary Turbines firing Natural gas	2143980	MMBTU/YR	Add-on VOC control is Oxidation Catalyst, and use of natural gas as fuel for pollution prevention	2	PPMVD@15%O2	3 H ROLLING AV BASED ON ONE H BLOCK AV
TX-0794	HILL COUNTY GENERATING FACILITY	TX	4/7/2016	Simple cycle turbine	171	MW	Premixing of fuel and air enhances combustion efficiency and minimizes emissions.			
TX-0788	NECHES STATION	TX	3/24/2016	Large Combustion Turbines >25 MW	232	MW	good combustion practices	2	PPM	
LA-0307	MAGNOLIA LNG FACILITY	LA	3/21/2016	Gas Turbines (8 units)	333	mm btu/hr	good combustion practices and fueled by natural gas			
TX-0790	PORT ARTHUR LNG EXPORT TERMINAL	TX	2/17/2016	Simple Cycle Electrical Generation Gas Turbines 15.210	34	MW	OXIDATION CATALYST	2	PPM	3-HR AVERAGE
PA-0306	TENASKA PA PARTNERS/WESTMOREL AND GEN FAC	PA	2/12/2016	Large Combustion turbine			Ox Cat and good combustion practices	1.4	PPMVD @ 15% O2	
PA-0306	TENASKA PA PARTNERS/WESTMOREL AND GEN FAC	PA	2/12/2016	Large combustion turbine			Ox Cat and good combustion practices	2.4	PPMDV@15% O2	
TX-0764	NACOGDOCHES POWER ELECTRIC GENERATING PLANT	TX	10/14/2015	Natural Gas Simple Cycle Turbine (>25 MW)	232	MW	Pipeline quality natural gas; limited hours; good combustion practices.	2	PPMVD @ 15% O2	
TX-0768	SHAWNEE ENERGY CENTER	TX	10/9/2015	Simple cycle turbines greater than 25 megawatts (MW)	230	MW	Pipeline quality natural gas; limited hours; good combustion practices.	1.4	PPMV	
TX-0733	ANTELOPE ELK ENERGY CENTER	TX	5/12/2015	Simple Cycle Turbine & Generator	202	MW	Good combustion practices	2	PPMVD @ 15% O2	
TX-0696	ROAN'S PRAIRIE GENERATING STATION	TX	9/22/2014	(2) simple cycle turbines	600	MW	good combustion	1.4	PPMVD	@15% O2 GE OPTION
MD-0044	COVE POINT LNG TERMINAL	MD	6/9/2014	2 COMBUSTION TURBINES	130	MW	THE USE OF PROCESS FUEL GAS AND PIPELINE NATURAL GAS, GOOD COMBUSTION PRACTICES, AND USE OF AN OXIDATION CATALYST	0.7	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	TWO (2) NATURAL GAS FIRED COMBUSTION TURBINES	283	MMBTU/H, EACH	GOOD COMBUSTION PRACTICES AND PROPER DESIGN	2.5	PPMVD AT 15% OXYGEN	1-HR AVERAGE
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	TWO (2) NATURAL GAS FIRED COMBUSTION TURBINES	283	MMBTU/H, EACH	GOOD COMBUSTION PRACTICES AND PROPER DESIGN	2.5	PPMVD AT 15% OXYGEN	1-HR AVERAGE
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	GE LMS-100 combustion turbines, simple cycle with water injection	1690	MMBTU/H	Oxidation catalyst; Limit the time in startup or shutdown.			

TABLE A-4: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.110 (SIMPLE CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	GE LMS-100 combustion turbines, simple cycle with water injection	1690	MMBTU/H	Oxidation catalyst; Limit the time in startup or shutdown.			
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FG-PEAKERS: 2 natural gas fired simple cycle combustion turbines	171	MMBTU/H	Efficient combustion; natural gas fuel.	2	PPMDV @ 15% O2 as CH4	
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	GE LM6000PC SPRINT Simple cycle combustion turbine	405.3	MMBTU/hr	utilize efficient combustion/design technology	11	PPMDV @ 15% O2 as CH4	
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	GE 7FA Simple Cycle Combustion Turbine	1780	MMBTU/HR	will utilize efficient combustion/design technology	1	PPMDV @ 15% O2 as CH4	
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Simple Cycle Turbine (EP03)	40	MW	Oxidation Catalyst	3	PPMV AT 15% O2	3-HOUR AVERAGE
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Simple Cycle Trubine (EP04)	40	MW	Oxidation Catalyst	3	PPMV AT 15% O2	3-HOUR AVERAGE
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Simple Cycle Turbine (EP05)	40	MW	Oxidation Catalyst	3	PPMV AT 15% O2	3-HOUR AVERAGE

Appendix B

Capital and Annual Cost Calculation Summaries

Summary of Economic Impact of Alternative Emission Controls

	CGS4	CGS5	CGS6	CGS7	CGS8	SPGS3	SPGS4	SPGS5	*Basis*
Baseline Operation (hours/yr)	303	1,689	1,626	2,143	1,667	597	453	406	*Highest two-year average in past five years*
				NOx CONTROL ALTERERNATIVES					
Baseline NOx Emissions Level									
(tons/yr)	37.65					32.19	24.30	21.69	*Highest two-year average in past five years*
(avg lb/MMBtu)	0.44					0.1357	0.1334	0.1348	*calculated*
(ppm @ 15% O2)	120					37	36	37	*calculated*
				Selective Catalytic Reduction					
Achievable Emissions Level									
(ppm @ 15% O2)	4					2	2	2	*Vendor (PMC) estimate*
(tons/yr)	1.26					1.75	1.34	1.18	*calculated*
Annual Emissions Reduction (tons/yr)	36.39					30.44	22.96	20.51	*calculated*
Capital Equipment Cost	$10,100,000					$12,500,000	$12,500,000	$12,500,000	*Vendor (PMC) CAPX cost*
Sales Tax	$464,600					$575,000	$575,000	$575,000	*4.6% Nevada sales tax*
Direct Installation Cost	$7,000,000					$8,500,000	$8,500,000	$8,500,000	*Vendor (PMC) direct installation cost*
Indirect Installation Cost	$3,697,600					$4,576,300	$4,576,300	$4,576,300	*35% of capital equipment cost (OAQPS Manual)*
Total Capital Cost	$21,262,200					$26,151,300	$26,151,300	$26,151,300	
Annualized Capital Cost	$2,028,400					$2,494,800	$2,494,800	$2,494,800	*20 yr equipment life, 7.14% ROI*
O&M Costs									
Catalyst changeout	$156,100					$156,100	$156,100	$156,100	*5 year life, 7.14% ROI, Vendor (PMC) catalyst cost*
Annual maintenance	$106,300					$130,800	$130,800	$130,800	*0.5% of total capital investment (OAQPS Manual)*
Power cost	$12,700					$25,100	$19,100	$17,100	*$0.0754/kwhr, estimated power loss in kw*
Lost capacity cost	$36,200					$36,200	$36,200	$36,200	*$21.60/kw-month @ 3 months, est. power loss in kw*
NH3 usage	$13,700					$11,500	$8,600	$7,700	*Estimated NH3 consumption at $0.69/gal*
Total Annualized Cost	$2,353,400					$2,854,500	$2,845,600	$2,842,700	
Cost Effectiveness ($/ton)	**$64,672**					**$93,779**	**$123,944**	**$138,633**	
				Dry Low NOx Combustor					
Achievable Emissions Level									
(ppm @ 15% O2)	25					9	9	9	*Vendor (GE) estimate*
(tons/yr)	7.88					7.86	6.04	5.33	*calculated*
Annual Emissions Reduction (tons/yr)	29.77					24.33	18.26	16.36	*calculated*
Capital Equipment Cost						$9,000,000	$9,000,000	$9,000,000	*Vendor (GE) estimate*
Sales Tax						$414,000	$414,000	$414,000	*4.6% Nevada sales tax*
Direct Installation Cost						$1,500,000	$1,500,000	$1,500,000	*Vendor (GE) estimate*
Indirect Installation Cost						$3,294,900	$3,294,900	$3,294,900	*35% of capital equipment cost (OAQPS Manual)*
Total Capital Cost	$19,000,000					$14,208,900	$14,208,900	$14,208,900	*Vendor (GE) estimate*
Annualized Capital Cost	$1,812,600					$1,355,500	$1,355,500	$1,355,500	*20 yr equipment life, 7.14% ROI*
O&M Cost									
Annual maintenance	$95,000					$71,000	$71,000	$71,000	*0.5% of total capital investment (OAQPS Manual)*
Power cost	$0					$342,500	$259,900	$232,700	*$0.0754/kwhr, estimated power loss in kw*
Lost capacity cost	$0					$492,800	$492,800	$492,800	*$21.60/kw-month @ 3 months, est. power loss in kw*
Total Annualized Cost	$1,907,600					$2,261,800	$2,179,200	$2,152,000	
Cost Effectiveness ($/ton)	**$64,069**					**$92,978**	**$119,316**	**$131,553**	
				VOC CONTROL ALTERERNATIVE					
Baseline VOC Emissions Level (tons/yr)	2.05	3.77	3.55	4.57	3.38				*Highest two-year average in past five years*
				Catalytic Oxidation					
Achievable Emissions Level (tons/yr)	0.41	0.75	0.71	0.91	0.68				*80% reduction*
Annual Emissions Reduction (tons/yr)	1.64	3.01	2.84	3.65	2.70				*calculated*
Capital Equipment Cost	$2,030,000	$2,500,000	$2,500,000	$2,500,000	$2,500,000				*Vendor (PMC) CAPX cost*
Sales Tax	$93,400	$115,000	$115,000	$115,000	$115,000				*4.6% Nevada sales tax*
Direct Installation Cost	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000				*Vendor (PMC) direct installation cost*
Indirect Installation Cost	$743,200	$915,300	$915,300	$915,300	$915,300				*35% of capital equipment cost (OAQPS Manual)*
Total Capital Cost	$4,366,600	$5,030,300	$5,030,300	$5,030,300	$5,030,300				
Annualized Capital Cost	$416,600	$479,900	$479,900	$479,900	$479,900				*20 yr equipment life, 7.14% ROI*
O&M Cost									
Catalyst changeout	$130,100	$130,100	$130,100	$130,100	$130,100				*5 year life, 7.14% ROI, Vendor (PMC) catalyst cost*
Annual maintenance	$21,800	$25,200	$25,200	$25,200	$25,200				*0.5% of total capital investment (OAQPS Manual)*
Power cost	$12,700	$71,100	$68,400	$90,200	$70,100				*$0.0754/kwhr, estimated power loss in kw*
Lost capacity cost	$36,200	$36,200	$36,200	$36,200	$36,200				*$21.60/kw-month @ 3 months, est. power loss in kw*
Total Annualized Cost	$617,400	$742,500	$739,800	$761,600	$741,500				
Cost Effectiveness ($/ton)	**$376,082**	**$246,514**	**$260,493**	**$208,543**	**$274,223**				

Appendix C

Public Utility Commission Capital Recovery Rate Information

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of Nevada Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto.	))))))	Docket No. 20-06003

At a general session of the Public Utilities Commission of Nevada, held at its offices on December 9, 2020.

PRESENT: Chair Hayley Williamson
Commissioner C.J. Manthe
Commissioner Tammy Cordova (Abstained)
Assistant Commission Secretary Trisha Osborne

FINAL ORDER

The Public Utilities Commission of Nevada ("Commission") makes the following findings of fact and conclusions of law:

I. INTRODUCTION

On June 1, 2020, Nevada Power Company d/b/a NV Energy ("NPC") filed with the Commission an application, designated as Docket No. 20-06003, for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto ("Application").

On September 9, 2020, the Commission issued an Interim Order directing NPC to return to ratepayers approximately $59.7 million in the form of a one-time bill credit.

On September 24, 2020, a Stipulation was filed with the Commission signed by all parties to this Docket (the "Parties"), which effectively modified the Interim Order and resolved all issues except for whether the overearnings sharing mechanism ("ESM") in NPC's Application should be continued.

On October 7, 2020, the Commission issued Interim Order No. 2 accepting the Stipulation and directing NPC to return to ratepayers approximately $120 million in the form of a one-time bill credit.

On October 12, 2020, the Commission held a hearing on whether the ESM in NPC's Application should be continued.

This final order incorporates the first Interim Order and Interim Order No. 2, including the entire Stipulation, and finds that continuation of the ESM is just and reasonable.

II. SUMMARY

The Commission incorporates into this order the first Interim Order and Interim Order 2, wherein the Commission accepted the Stipulation granting in part the Application as modified by this order, and finds that there should be a continuation of the ESM ordered in Docket No. 17-06003.

III. EXECUTIVE SUMMARY

Every three years, the Commission conducts a comprehensive review and financial analysis of NPC and the rates charged to Southern Nevada customers in a general rate case ("GRC"). The purpose of this review is to ensure that the interests of Southern Nevada ratepayers and those of NPC are reasonably and fairly balanced and to ensure that prudent decisions are being made that result in just and reasonable rates. The purpose of a GRC is to determine the amount of money that NPC needs to collect from customers through rates, otherwise known as a utility's revenue requirement, and establish rates that customers must pay to allow NPC to meet its revenue requirement. Generally, a GRC is split into three phases: (1) Cost of Capital; (2) Revenue Requirement; and (3) Rate Design. The Cost of Capital phase determines a utility's return on equity ("ROE"); the Revenue Requirement phase addresses the amount of revenue the utility must receive from the customers to cover its operating costs and investments in facilities, provide safe and reliable service to customers, and provide an opportunity to earn a fair return for shareholders on investments; and the Rate Design phase determines the rates that each class of customers must pay to provide the utility with its revenue requirement.

In this docket, NPC filed an Application seeking a $120-million reduction in its revenue requirement. The Commission did not hold a hearing regarding the Cost of Capital, Revenue Requirement, or Rate Design as the Parties settled all aspects of the case except for the ESM. The Parties stipulated that NPC would issue a $120-million one-time bill credit to customers, utilize an ROE of 9.4 percent, have a total revenue requirement of $1.0702 billion, and make certain agreed-upon adjustments to rates and fees.

In NPC's 2017 GRC, the Commission adopted an ESM to allow ratepayers to share in any potential overearnings by NPC. Under the terms of the mechanism, NPC was allowed to retain 100 percent of overearnings above its authorized 9.4-percent ROE up to 9.7 percent and 50 percent of overearnings above 9.7 percent. The remaining 50 percent of overearnings above 9.7 percent was to be returned to ratepayers in the instant proceeding. NPC recorded the ratepayers' share of overearnings for the calendar years 2018 and 2019 in a regulatory liability account for presentation in this docket.

The Commission, after a hearing on this issue, finds that continuation of the ESM is just and reasonable. The Commission finds that there were extenuating circumstances in 2017 that led the Commission to implement earnings-sharing, but that does not diminish the potential effectiveness of the mechanism on a going-forward basis. The ESM approved by the Commission in Docket No. 17-06003 includes a band of 30 basis points above the approved ROE of 9.4 percent, within which NPC retains all of the overearnings. The Commission notes that the earnings-sharing has accumulated approximately $63 million in the regulatory liability for the 2018 and 2019 calendar years.

This order summarizes the Stipulation filed in this case as well as the relevant evidence and arguments presented by the Parties in the ESM hearing.

IV. LEGAL STANDARD OF REVIEW

The filings in this case are made pursuant to the Nevada Revised Statutes ("NRS") Chapters 703 and 704, as well as the Nevada Administrative Code ("NAC") Chapters 703 and 704.

The Commission's statutory obligation in GRC proceedings is to ensure that the rates charged for service by the utility are just and reasonable.[1] More specifically, NRS 704.001(4) requires that the Commission "balance the interests of customers and shareholders of public utilities by providing public utilities with the opportunity to earn a fair return on their investments while providing customers with just and reasonable rates." Similarly, NRS 704.040(1) provides that "[e]very public utility shall furnish reasonably adequate service and facilities" and "the charges made for any service rendered or to be rendered, or for any service in connection therewith or incidental thereto, must be just and reasonable." Meanwhile, NRS 704.040(2) states that every unjust and unreasonable charge for service of a public utility is unlawful.

NRS 704.120(1) provides that "[i]f, upon any hearing and after due investigation, the rates, tolls, charges, schedules or joint rates shall be found to be unjust, unreasonable or unjustly discriminatory, ... the Commission shall have the power to fix and order substituted therefore such rate or rates, tolls, charges or schedules as shall be just and reasonable."

The PUCN has broad authority to fix and remedy rates and charges that are unjust, unreasonable, discriminatory or preferential. *See* NRS 704.120(1). An order by the Commission will be upheld by a court on judicial review when it is "within the legal framework of the law, and based on substantial evidence in the record." *NPC Co. v. Public Utilities Commission of Nevada, et al.*, 122 Nev. 821, 834, 138 P.3d 486, 494 (2006) (other internal citations and quotations omitted). Substantial evidence is that which "'a reasonable mind might accept as adequate to support a conclusion.'" *Id.* (quoting *State of Nevada Emp. Security v. Hilton Hotels*, 102 Nev. 606, 608, 729 P.2d 497, 498 (1986)).

Great deference is afforded to the Commission's "interpretation of its governing statutes or regulations," *see Dutchess Business Service, Inc. v. Nevada State Board of Pharmacy*, 124 Nev. 701, 709, 191 P.3d 1159, 1165 (2008), and a court will not "reweigh the evidence" or substitute its judgment on factual questions. *NPC Co.*, 122 Nev. at 495, 138 P.3d at 494; NRS 703.373(11). Evaluating the credibility of witness testimony and the weight to be given to it

[1] *See* Nevada Revised Statutes ("NRS") 703.150, 704.001, 704.040 704.110, 704.120.

resides well-within the province of the Commission, *i.e.*, fact finder. *See In the Matter of TR v. State*, 119 Nev. 646, 649, 80 P.3d 1276, 1278 (2003). This standard holds true even when expert testimony is conflicting. *See Allen v. State*, 99 Nev. 485, 487-88, 665 P.2d 238 (1983). Indeed, the Nevada Supreme Court has recognized that "[e]xpert testimony is not binding on the trier of fact; [triers of fact] can either accept or reject the testimony as they see fit." *Id.*

The Commission may also take "[n]otice of judicially cognizable facts and generally recognized technical or scientific facts within the specialized knowledge of the agency," NRS 233B.123(5), and its final decisions "shall be deemed reasonable and lawful" and have operative effect unless they are set aside by a higher court on review upon a showing of clear error or abuse of discretion. *See* NRS 703.373(9) and (11); *see also* NRS 703.374(2).

V. PROCEDURAL HISTORY

- On June 1, 2020, NPC filed the Application.

- NPC filed the Application pursuant to the NRS and the NAC, Chapters 703 and 704, including, but not limited, to NRS 704.100, NRS 704.110, NAC 703.2201 through 703.2481, NAC 703.535, and NAC 704.6502 through 704.6546.

- On June 8, 2020, the Commission issued a Notice of Application for Authority to Adjust Annual Revenue Requirement for General Rates Charged to all Classes of Electric Customers.

- On June 9, 2020, the Commission issued a Notice of Prehearing Conference, and the Nevada Bureau of Consumer Protection ("BCP") filed a Notice of Intent to Intervene pursuant to NRS Chapter 228.

- The Regulatory Operations Staff of the Commission ("Staff") participates as a matter of right pursuant to NRS 703.301.

- On June 12, 2020, Walmart, Inc. ("Walmart") filed a Petition for Leave to Intervene ("PLTI").

- On June 17, 2020, Kroger Co. ("Kroger") filed a PLTI, Motion for Admission Pro Hac Vice, and Notice of Association of Counsel.

- On June 29, 2020, the Colorado River Commission of Nevada ("CRCNV") filed a PLTI.

- On June 30, 2020, Nevada Cogeneration Associates #1 ("NCA"), Sunrun, Inc. ("Sunrun"), MGM Resorts International ("MGM"), and Caesars Enterprise Services, LLC ("Caesars") each filed PLTIs.

- On July 1, 2020, Wynn Las Vegas, LLC ("Wynn"), Circus Circus Las Vegas, LLC ("CCLV"), and Smart Energy Alliance ("SEA") (collectively, "WCS") filed a joint PLTI, and the Southern Nevada Gaming Group ("SNGG")[2] filed a PLTI.

- On July 9, 2020, the Commission held a prehearing conference. NPC, Staff, BCP, Caesars, CRCNV, Kroger, MGM, NCA, SNGG, Sunrun, Walmart, and WCS appeared and discussed a procedural schedule and the PLTIs.

- On July 15, 2020, the Commission issued a Procedural Order.

- On July 16, 2020, the Commission issued a Notice of Consumer Session and Notice of Hearing, and an Order granting the PLTIs of Caesars, CRCNV, Kroger, MGM, NCA, SNGG, Sunrun, Walmart, and WCS.

- On July 21, 2020, Staff and BCP (together, the "Movants") filed a Joint Motion for an Order Shortening Time, and the Commission issued Procedural Order No. 2.

- On July 22, 2020, NPC filed a Response to the Joint Motion's request for an Order Shortening Time, and the Commission issued an Order denying the Movant's request for an Order Shortening Time.

- On July 28, 2020, Caesars and MGM, NPC, and WCS filed Responses.

- On August 3, 2020, the Movants filed a Reply, and NPC submitted its Cost of Capital certification filing.

- On August 7, 2020, the Commission issued an Order denying the Joint Motion, Procedural Order No. 3, and a Notice of Hearing.

- On August 13, 2020, the Commission issued a Notice of Prehearing Conference and Procedural Order No. 4.

- On August 17, 2020, BCP, SNGG, Staff, and WCS each filed Prepared Direct Testimony, Caesars and MGM filed Joint Prepared Direct Testimony, and NPC submitted its Revenue Requirement Certification filing.

- On August 18, 2020, Kroger filed Prepared Direct Testimony.

- On August 25, 2020, the Commission held an informal prehearing conference. NPC, BCP, Staff, Caesars, MGS, Kroger, Sunrun, SNGG, CRCNV, WCS, and Walmart participated. The Commission gave a presentation on the functionality of Microsoft Teams to the participants.

- On August 26, 2020, NPC filed Prepared Rebuttal Testimony.

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[2] Southern Nevada Gaming Group consists of the Boyd Gaming Corporation, Las Vegas Sands Corp., Stations Casinos LLC, Plaza Hotel and Casino, LLC, Tropicana Las Vegas Inc., and LVGV, LLC.

- On August 27, 2020, the Commission issued Procedural Order No. 5.
- On August 28, 2020, NPC, WCS, SNGG, MGM and Caesars, BCP, and Staff each filed an exhibit list and cross-examination statement, and NPC submitted its Rate Design Certification filing.
- On August 31, 2020, Kroger filed an exhibit list, and NPC filed the information requested by the Commission in Procedural Order No. 5.
- On September 1, 2020, NPC filed a whitepaper providing Supplemental Direct Testimony, and Staff, BCP, Caesars, MGM, SNGG, Kroger, Walmart, WCS, and CRCNV (collectively, Signatories to the Agreement") filed an Agreement.
- On September 1, 2020, the Presiding Officer held a hearing. NPC and the Signatories to the Agreement, except for CRCNV, made appearances, presented their witnesses and exhibits, and conducted cross-examination. During the hearing, the Presiding Officer granted oral motions to accept exhibits into the record pursuant to NAC 703.730.
- On September 3, 2020, NPC filed a revised attachment to its Revenue Requirement Certification testimony.
- On September 4, 2020, BCP and Staff filed Prepared Direct Testimony in the Cost-of-Capital phase of the proceeding; MGM, Caesars, and WCS filed Joint Prepared Direct Testimony in the Cost-of-Capital phase of the proceeding; and NPC filed late-filed Exhibit No. 148.
- On September 8, 2020, BCP filed a correction to Direct Testimony.
- On September 9, 2020, the Commission issued Procedural Order No. 6 and the Interim Order.
- On September 10, 2020, the Commission held a consumer session.
- On September 22, 2020, the Commission issued Procedural Order No. 7.
- On September 24, 2020, the Parties filed a Stipulation and Supplement to the Stipulation. Staff and BCP filed Direct Testimony, SNGG filed Direct Testimony, and the Supplement to Direct Testimony as agreed to in the Stipulation.
- On September 28, 2020, the Commission issued Procedural Order No. 8.
- On September 29, 2020, NPC filed information regarding rates proposed in the Stipulation as requested in Procedural Order No. 8.
- On September 30, 2020, NPC filed a letter advising the Commission that it had filed Exhibit 3 to the Stipulation containing Settlement Statement O.

- On September 30, 2020, the Presiding Officer held a continued prehearing conference. The Parties made appearances and discussed the Stipulation. At the conclusion of the prehearing conference, the Presiding Officer granted an oral motion to accept Exhibits 150 - 151 into the record pursuant to NAC 703.370.

- On October 1, 2020, the Commission issued a Notice of Hearing.

- On October 6, 2020, NPC filed Prepared Rebuttal Testimony.

- On October 7, 2020, the Commission issued Procedural Order No. 9 and Interim Order No. 2.

- On October 8, 2020, NPC, SNGG, BCP, and Staff each filed an exhibit list and cross-examination statement.

- On October 12, 2020, the Presiding Officer held a hearing. NPC, SNGG, BCP, and Staff made appearances, presented their witnesses and exhibits, and conducted cross-examination. During the hearing, the Presiding Officer granted oral motions to accept exhibits 152, 153, 154, 1001, 1002, 1003, 1004, 403, and 305 into the record pursuant to NAC 703.730.

- On October 14, 2020, NPC filed information for issuing bill credits to customers as directed in Interim Order No. 2.

- On November 13, 2020, NPC filed revised tariff sheets.

- On November 20, 2020, NPC filed information regarding the number of credits issued and total dollar value of credits for each customer class and the impact of the bill credit as directed in Interim Order No. 2.

VI. STIPULATION

1. The Parties agree that the Stipulation provides a reasonable resolution of issues raised in the Application and that the Stipulation is in the public interest. (Ex. 150 at 1.) The Parties agree that NPC will issue a $120-million one-time bill credit to customers, utilize a Return on Equity of 9.4 percent, have a total revenue requirement of $1.0702 billion, and make certain agreed-upon adjustments to rates and fees. (*Id.*)

<u>Cost of Capital and Revenue Requirement</u>

2. The Parties agree that NPC shall issue a $120-million one-time bill credit to be distributed to customers based on the calculation of recorded rate base tariff general rate

("BTGR") revenues using non-normalized billing determinants for calendar year 2019. (*Id.* at 4-5.) The one-time bill credit includes: (1) the $59.7-million earnings sharing regulatory liability as ordered by the Commission in the September 9, 2020, Interim Order; (2) $26 million from the unprotected excess accumulated deferred income tax ("ADIT") regulatory liability; (3) expected earnings-sharing for 2020 of $20 million, which will act as a reduction to the 2020 overearnings balance accepted by the Commission in future proceedings; (4) approximately $9 million in carrying charges on the earnings-sharing regulatory liability that accrued during calendar years 2019 and 2020, and (5) approximately $5 million in other expense adjustments. (*Id.* at 5.)

3. The final class allocations of the credit amounts are presented in Exhibit 1 to the Stipulation entitled Settlement One-Time Credit Allocation. (*Id.*) The Parties explain that:

a. BTGR revenues will include impact fee revenues for distribution-only service ("DOS") customers consistent with "present" BTGR revenues for 2019 as presented in Statements J and O in the original application.

b. A proportionate allocation to each rate schedule would result in each rate schedule receiving an equal percentage credit applicable to each rate schedule's recorded 2019 BTGR revenues.

c. For rate schedules applicable to large non-residential customers (LGS-2, LGS-3, LGS-X, LGS-2-DOS, LGS-3-DOS, LGS-X-DOS), the overearnings refund will be based directly on the total recorded BTGR revenue contributed by each such large customer by meter during calendar year 2019. Using this method, the meter-specific refund would apply the equal percentage credit to the BTGR revenues attributable to each large-customer meter in 2019.

d. If the final calculation of the 2020 overearnings is less than $20 million, NPC will not seek recovery from customers of any of the $20 million representing the 2020 overearnings. If the final calculation of the 2020 overearnings is more than $20 million, such amount will be due to ratepayers consistent with the Order in Docket No. 17-06003 or other applicable Commission Order.

(*Id.* at 5-6.)

4. The Parties agree that NPC's ROE will be set at 9.4 percent and that the rate of return ("ROR") will be set at 7.14 percent. (*Id.* at 6.)

5. The Parties agree that NPC's total revenue requirement will be set at $1.0702 billion, which reflects: (1) NPC's expected change in circumstance adjustments; (2) Staff's weather normalization adjustment; (3) the $59.7-million of 2018 and 2019 earnings sharing regulatory liability as part of the $120-million one-time credit; (4) $26 million of unprotected ADIT regulatory liability as part of the $120-million one-time credit; (5) a 9.4-percent ROE; and (6) a "black box" settlement revenue requirement adjustment to reach the stipulated amount. (*Id.*)

6. The Parties agree that the cost recovery associated with the Reid Gardner and Navajo power plants is incorporated into the revenue requirement as proposed by NPC such that there is no impairment of cost recovery relative to NPC's filing. This includes a regulatory asset balance of $112.4 million in decommissioning and remediation costs for Reid Gardner per I-CERT-30, a regulatory asset and balance credit of $1.65 million for Navajo per I-CERT-31, and a regulatory asset balance of $0.678 million per I-CERT-28 for Mohave. These costs are to be recovered over the period of 2021-2023 as reflected in the filing and are approved by all parties. Future additional costs incurred by NPC associated with these facilities will be included as part of future GRC proceedings. All parties reserve their rights to review and make

recommendations regarding recovery of future costs and whether and how the costs should be allocated to all customers in future GRC proceedings. (*Id.*)

7. NPC agrees to a tiered interconnection fee that provides for a lower fee for smaller distributed generation ("DG") systems and higher fee for larger DG systems, instead of the averaged fee currently proposed for all DG systems. The tiered interconnection fees are provided in Exhibit 2 to the Stipulation. (*Id.* at 7.)

8. NPC agrees to convene an ad hoc interconnection working group open to all interested stakeholders, with a goal to gain process efficiencies and cost reductions. The working group will convene at the request of any stakeholder on an as-needed basis. Topics for discussion shall include process improvements and cost reductions for interconnections that involve main panel upgrades, energy storage, and other issues as they arise. NPC agrees to jointly petition the Commission along with stakeholders to seek any necessary approvals to implement agreed-upon process changes, as appropriate. In the event that NPC and stakeholders disagree regarding any interconnection issue addressed in the working group, NPC agrees, on an annual basis and if necessary, to jointly petition the Commission to seek formal resolution. (*Id.*)

9. NPC commits to engaging in good-faith negotiations with the CRCNV prior to April 1, 2021, to discuss modifications to the Hoover D tariff that is scheduled to change January 1, 2022. (*Id.*)

<u>Rate Design</u>

10. The Parties agree that NPC's rate design will use Staff's trend weather normalization methodology that the Commission adopted in Sierra Pacific Power Company's ("SPPC") 2019 rate case. (*Id.*)

11. The Parties agree that NPC's rate design will use Generation Allocators, not Generation & Energy Allocators, which the Commission adopted to allocate generation demand costs in SPPC's 2019 rate case. (*Id.*)

12. The Parties agree that NPC's rate design will not include energy costs (Base Tariff Energy Rate ("BTER")) in adjusting class revenue requirement for policy considerations in Statement O, Tab "Passes." More broadly, while it is acceptable to list energy costs (BTER) in Cost of Service Study and Statement O, they should not be used in any BTGR calculations or "Interclass Revenue Adjustments." (*Id.* at 8.)

13. The Parties agree that NPC's rate design will not shift all claimed net energy metering ("NEM") revenue shortfalls to the corresponding otherwise applicable class (e.g., NMR schedules to RS schedule), which inflates NPC's calculated subsidy for the corresponding otherwise applicable class (e.g., RS). (*Id.*)

14. The Parties agree that NPC's rate design will use Exhibit Pollard Cert-20, Statement O-ECS-E Proposed Revenue Requirement-Proposed Rates, as adjusted and proposed in Exhibit 3 attached to the Stipulation ("Settlement Statement O"). In the event of any ambiguity or perceived divergence between the language of this Stipulation and the rates identified in Settlement Statement O, Settlement Statement O will control. (*Id.*)

15. The Parties agree to accept the rates contained in Settlement Statement O as the tariffed rates effective January 1, 2021. (*Id.*)

16. The Parties agree that when the claimed NEM revenue shortfalls are placed back to their appropriate rate classes (e.g., from RS to RS-NEM and RM to RM-NEM), Settlement Statement O shows that there is no subsidy for non-NEM residential customers. (*Id.*)

17. The Parties agree that NPC's embedded cost-of-service study filed in this GRC used marginal cost allocators and such allocators are not generally accepted in embedded cost-of-service studies used in other state jurisdictions. (*Id.*)

18. The Parties agree that, not later than January 5 of the year in which NPC files its next GRC, NPC agrees to meet with Staff, BCP, and interested interveners to discuss embedded cost allocators to be used in an embedded cost-of-service study that will be filed in NPC's next GRC. NPC will notify the Parties of such meeting(s) reasonably in advance to provide the Parties an opportunity to participate. (*Id.* at 8-9.)

19. The Parties agree that NPC will make the following changes to the LGS-2S schedule rates:

a. Adjust the On Peak Generation Demand per-kilowatt charge to $12.81 and increase the Mid Peak Generation Demand per-kilowatt charge to $2.65.

b. Commensurately decrease the On Peak, Mid Peak, Off Peak, and Other time-of-use ("TOU") energy per-kilowatt-hour charges so that the net impact is revenue-neutral to NPC, while also maintaining NPC's proposed ratios between the TOU energy charges.

(*Id.* at 9.)

20. The Parties agree that NPC will provide an updated review of TOU periods in its next GRC. (*Id.*)

21. The Parties agree that NPC has complied with Directive 20 in the Commission's Modified Final Order in Docket No. 19-06002 to review its TOU periods. (*Id.*)

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<u>Continuation of the Earnings-Sharing Mechanism</u>

22. The Parties agree that the issue of whether to continue the ESM ordered in Docket No. 17-06003 will be resolved via a limited hearing before the Commission. (*Id.* at 1-2.)

23. The Parties agree that Staff, BCP, SNGG, and NPC will file testimony and participate in a hearing and that all other Parties have agreed to not file testimony and have waived their rights to perform cross-examination of any witness during the hearing on October 12, 2020. (*Id.* at 10.)

24. The Parties agree that nothing in the Stipulation shall be construed to prevent any party from addressing earnings-sharing in Docket No. 19-06008, the rulemaking for Senate Bill 300 ("SB 300") alternative ratemaking, or in future general rate review proceedings. (*Id.*)

25. The Parties agree that as part of the Stipulation, NPC agrees to withdraw its appeal filed with the Nevada Supreme Court (Case No 81154, regarding the ADIT tax issues.) (*Id.*)

Commissions Discussion and Findings

26. The Commission finds that the Stipulation complies with the requirements of NAC 703.845 in that it settles only issues relating to the instant proceeding and does not seek relief that the Commission is not otherwise empowered to grant. The Stipulation is a consensus resolution of the issues pursuant to the Parties' negotiations and is a reasonable recommendation and resolution of the issues in this proceeding.

27. All arguments of the Parties raised in these proceedings not expressly addressed herein have been considered and either rejected or found to be non-essential for further discussion in this Order. Any agreements and recommendations contained in the Stipulation, but not expressly addressed herein, are either agreements by the Parties regarding matters non-

essential to the disposition of this docket or are recommendations for specific findings that do not require delineation given the Commission's acceptance of the Stipulation.

28. Therefore, the Commission incorporates the first Interim Order and Interim Order No. 2, wherein the Commission accepted the Stipulation, into this order.

VII. CONTINUATION OF THE EARNINGS-SHARING MECHANISM

Background and Overview

29. In NPC's 2017 GRC, Docket No. 17-06003, the Commission adopted an ESM to capture any potential overearnings by NPC.[3] Under the terms of the mechanism, NPC was allowed to retain 100 percent of overearnings above its authorized 9.4 percent ROE up to 9.7 percent and 50 percent of overearnings above 9.7 percent. The remaining 50 percent of overearnings above 9.7 percent was to be returned to ratepayers in the instant proceeding.

30. In the instant proceeding, the Parties were unable to reach consensus on whether to continue the ESM and agreed to hold a limited hearing on the issue. (*See* Stipulation.) NPC and Staff recommend ceasing the ESM. (Ex. 154 and 305.) Both NPC and Staff have taken the position that the ESM is better addressed through the alternative ratemaking process being considered in Docket No. 19-06008 implementing SB 300. (Ex. 154 and 305.) SNGG recommends the continuation of the ESM and states that any changes to the ESM should occur through the alternative ratemaking process. (Ex. 1001.) BCP recommends continuing the ESM and makes other recommendations regarding carrying charges, excludable costs, audit timing, and the appropriate asymmetry of the mechanism. (Ex. 403.)

31. NPC also states that other unresolved issues and specific concerns exist regarding continuing the ESM, including that: it is discriminatory in that only NPC and SPPC are subject

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[3] Administrative notice was taken of the Modified Final Order in Docket No. 17-06003.

to earnings-sharing; the current regulatory framework without earnings-sharing already effectively balances customer and shareholder interests; extenuating circumstances existed in 2017; the current asymmetrical earnings-sharing, without a corresponding sharing of under-earnings, deprives a utility of the opportunity to earn a fair and reasonable return in different economic environments; and achieving a fair incentive ratemaking mechanism is complicated and outstanding issues exist with the current mechanism. (Ex. 154 at 3-6.)

Party Positions

SNGG's Position

32. SNGG states that there is no reason to discontinue the currently-approved ESM and disrupt the status quo for ratemaking, especially at a time in which earnings-sharing has proven to provide considerable customer protection, there is economic uncertainty related to the ongoing COVID-19 pandemic, and the Commission is in the process of adopting procedures within Docket No. 19-06008, pursuant to NRS 704.762. (Ex. 1001 at 2, Tr. 322-25.)

33. SNGG states that the facts may have changed since the last rate case but the need for continued customer protection has not changed. (Ex. 1001 at 3.) SNGG states that, based on 2018 and 2019, NPC earned at least $120 million in excess of the 9.7-percent ROE, with 50 percent of that shared with customers, plus another $14.5 million[4] in equity earnings between the approved ROE of 9.4 percent and 9.7 percent (*Id.*) SNGG states that, even with the rate reduction expected from this rate case, it is not known whether this excess earning will continue because it is dependent on a number of variables once this rate case is complete. (*Id.*)

34. SNGG states that SB 300 mandated that the Commission establish procedures for an electric utility to apply to the Commission for approval of an alternative ratemaking plan. (*Id.*

[4] Assuming a rate base of $4.819,552,000, multiplying it by 49.99 percent and then by 0.30 percent (30 basis points) equals $7,227,837; multiplying that by 2 years equals $14,455,674.

at 4.) SNGG states that, at the time of passage of SB 300, NPC was already operating under the currently approved earnings sharing mechanism and SPPC had an earnings sharing approved by the Commission just last year, shortly following passage of SB 300.[5] (*Id.*) SNGG states that ESMs are now part of the current ratemaking plan for electric utilities in Nevada based upon Commission orders and SB 300. (*Id.*) SNGG explains that the Commission Order in Docket No 17-06003 created a rule of general applicability to the ESM for NPC, which remains in effect until the Commission alters that mechanism. (*Id.*; Tr. 308.)

35. SNGG states that, if NPC wants to petition the Commission for a change in ratemaking methodology, it should wait until the rulemaking considerations in Docket No. 19-06008 are completed and then, at a more appropriate time, the Commission may consider the role of the ESM. (*Id.*; Tr. 323.)

36. SNGG states that NPC's history of excess earnings above the approved rate of return supports the ESM's continuation. (Ex. 1001.at 5; *see* Blank Table 1, Tr. 323-24.) SNGG points out that even as recently as the 12 months that ended on June 30, 2020, NPC is reporting over $66 million in excess of the approved ROE. (*Id.*) SNGG argues that this demonstrates that the specific concerns at issue when the Commission first approved the ESM are not the only reasons why excessive earnings may occur. (*Id.*)

37. SNGG dismisses NPC's concerns regarding the asymmetrical nature of the ESM, noting that NPC can file a rate case at any time and has control over the timing of expenditures and investments. (*Id.* at 7.) SNGG states that, furthermore, one reason why the ESM is designed asymmetrically and not symmetrically is to avoid perverse incentives for cost control by the utility if it can recover uncontrolled excess expenditures through the ESM. (*Id.*)

[5] Docket No. 19-06002, Modified Final Order dated April 2, 2020.

38. SNGG states that NPC's references to NRS 703.151 and 704.120(1) do not alter SNGG's belief that the ESM helps balance asymmetry in the timing of rate cases. (*Id.*) SNGG states that, although the Commission indeed has the authority to issue an order for a utility to appear and show cause as to why its rates continue to be just and reasonable, show-cause proceedings are rare and this authority does not reside with customers. (*Id.*) Further, SNGG states that the Commission's authority is not a substitute for an ESM, which allows a partial remedy for excessive returns within the year in which they occur. (*Id.* at 7-8.)

39. SNGG notes that the current pandemic weighs in favor of retaining the ESM. (*Id.* at 8.) SNGG states that the Commission allowed NPC to create a regulatory asset for COVID-19-related costs.[6] (*Id.*) SNGG asserts that the disposition of the COVID-19 regulatory asset could increase earnings but, without the ESM, customers would have no protection against overearnings that may result. (*Id.*)

BCP's Position

40. BCP states that it supports the continuation of the ESM. (Ex. 403. at 10.) BCP states that, first, the ESM mechanism not only incentivizes cost-cutting measures by the utility, but it also protects ratepayers against excessive over-earnings by the utility that could result from these cost-cutting measures between rate cases. (*Id.*) BCP notes that this utility has had a long and consistent history of overearning. (*Id.*) BCP states that, moreover, it is important to note the reasonableness of the current ESM structure that allows NPC to retain 100 percent of any excess earnings up to 30 basis points above the authorized ROE and then shares excess earnings with ratepayers after that. (*Id.* at 10-11.)

[6] Emergency Order related to utility service and COVID-19, Docket No. 20-03021, March 27, 2020.

41. BCP states that it does not agree that the ESM should be changed to make it symmetrical in that under-earnings, like overearnings, should be shared with ratepayers. (*Id.* at 11.) BCP states that, first, any discussion of a symmetrical ESM where under-earnings (below the band) are shared evenly with ratepayers is, at this time, a theoretical discussion at best because NPC has consistently over-earned from 2014 forward. (*Id.*) BCP notes that ratepayers have little to no recourse when a public utility is over-earning but that utilities have ample protection against the risk of under-earnings: (1) by controlling investment levels between rate cases, which is where the under-earnings would come from or (2) by filing a rate case when under-earnings are eminent or start to appear at any significant level. (*Id.*)

42. BCP states that the ESM regulatory liability balance is being filed in NPC's annual Deferred Energy Accounting Adjustment ("DEAA") filing each year but that the merits of the calculations and resulting balance are not being analyzed in those filings.[7] (*Id.* at 12; Tr. 362, 370-71.)

43. BCP states that the merits of the ESM calculations should be audited in NPC's next GRC because the merits of the ESM calculations cannot be thoroughly reviewed in the DEAA filings because no other BTGR information is filed in those cases, only BTER information is filed in a DEAA filing. (*Id.* at 12-13; Tr. 371.)

44. BCP recommends that the Commission clarify that the ESM calculations will be audited in NPC's next GRC. (*Id.* at 13.)

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[7] **Docket No. 19-03001, Commission Order, August 1, 2019, Attachment 1 Stipulation; and, Docket 20-02026, Commission Order, August 1, 2019, Attachment 1 Stipulation.**

Staff's Position

45. Staff states that it recommends that the Commission authorize NPC to cease the accrual of an earnings-sharing regulatory liability after December 31, 2020. (Ex. 305 at 1.)

46. Staff states that the Commission established the ESM in NPC's last GRC, Docket No. 17-06003, and it was initiated to address a unique situation where future benefits, such as debt refinancing at lower interest rates and the effect of a lower income tax rate, could flow to the benefit of NPC's shareholders as well as its ratepayers.[8] (*Id.* at 1-2.) Staff states that the benefits to shareholders and ratepayers have been captured for calendar years 2018 and 2019, while potential benefits for 2020 will be addressed in NPC's next GRC and DEAA proceeding. (*Id.* at 2.) Staff states that, with the setting of new rates effective January 1, 2021, the unique set of circumstances have passed and the impetus for an ESM will have passed. (*Id.*)

47. Staff states that in open Docket No. 19-06008, the rulemaking to amend, adopt, and/or repeal regulations in accordance with SB 300, the Commission and interested parties are exploring, in a collaborative manner, alternative ratemaking methods, including an ESM. (*Id.*) Staff states that Docket No. 19-06008 is the appropriate forum in which to evaluate the benefits and disadvantages of implementing any ESM. (*Id.*) Staff explains that, for example, one issue that will need to be considered in the context of an ESM is the symmetry between excess earnings and a shortfall in earnings and, if so, whether there should be a resulting change in ROE. (*Id.*) Therefore, Staff recommends that the Commission authorize NPC to cease accrual of an earnings-sharing regulatory liability after December 31, 2020. (*Id.*)

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[8] *See* Docket No. 17-06003, Modified Order Granting in Part and Denying in Part General Rate Application by Nevada Power at 3, Executive summary: New Earnings-Sharing Mechanism to Capture Overearnings, issued December 29, 2017.

NPC Rebuttal

48. NPC states that an ESM is not necessary for the Commission to fulfill its obligations to establish fair and reasonable rates. (Ex. 154 at 6.) NPC states that NPC and SPPC (electric operations) are required pursuant to NRS 704.110(3) to make a GRC filing no less frequently than every three years. (*Id.*) NPC states that, moreover, the Commission has the ability, pursuant to NRS 703.151 and 704.120(1), to require NPC to file for a rate review at any time. (*Id.*) NPC states that regulatory lag is an inherent part of the regulatory construct but, when combined with the Nevada statutes referenced above, the existing regulatory framework ensures fair and reasonable rates. (*Id.*)

49. NPC states that the key factors that supported an ESM in Docket Nos. 17-06003 and 17-06004[9] no longer exist. (*Id.* at 7.) NPC notes that the testimony in Docket Nos. 17-06003 and 17-06004 recommended an ESM based on historical overearnings, along with significant debt maturities and potential tax reform over the rate-effective period. (*Id.*) NPC further notes that the Commission order reiterated the key factors by stating, "This earning sharing mechanism eases concerns regarding NPC receiving a windfall for refinancing long-term debt at cheaper rates and incurring savings from future changes to federal tax legislation."[10] (*Id.*) NPC asserts that the factors that supported earnings-sharing in 2017 will be fully reflected in customer rates effective January 1, 2021; thus, the factors that drove the establishment of the ESM no longer exist. (*Id.*) Moreover, NPC explains that it is not scheduled for any major debt refinancing and that NPC revised rates via a tax rate reform rider approved in Docket No. 18-02010. (*Id.* at 7-9, *see also* Chart Cole 1 and Chart Cole 2.)

[9] Docket No. 17-06003 was consolidated with Docket No. 17-06004 wherein NPC filed a separate application for approval of new and revised depreciation and amortization rates for its electric and common accounts.

[10] *See* Docket Nos. 17-06003 and 17-06004, December 19, 2018, Modified Final Order at 114, para. 466.

50. NPC explains that the continuation of the ESM is unfair to NPC because it is asymmetrical as it must share potential upside with customers but bears all the potential downward risks. (*Id.* at 9.) NPC explains that, under symmetrical ESM, NPC benefits or is disadvantaged within a certain deadband on either side of the allowed return on equity. (*Id.*) For example, assuming a deadband of 30 basis points and a 9.4-percent allowed return on equity, NPC retains all risks and benefits so long as the actual returns are between 9.1 percent and 9.7 percent. (*Id.*) NPC further explains that underperformance below 9.1 percent and over-performance above 9.7 percent would be shared with customers using a sharing percentage (i.e., 50 percent in Docket Nos. 17-06003 and 17-06004). (*Id.* at 9-10.)

51. NPC explains that a simple example will illustrate the inequities of an asymmetrical ESM. (*Id.* at 10.) NPC states that the revenue requirement utilizes historical costs and tariffs that are based on normal weather. (*Id.*) NPC states that, if weather in a particular year is much warmer than normal, asymmetrical ESM would require the utility to share excess earnings with customers. (*Id.*) NPC notes, if weather in the following year is much cooler than normal by an equal amount, then asymmetrical ESM would result in the utility bearing the full financial impact of these under-earnings. (*Id.*)

52. NPC asserts that the design of an asymmetrical ESM deprives NPC of the ability to earn the established rate of return given that the downside risk exceeds the potential upside return. (*Id.* at 11.) NPC argues that the solution is either a symmetrical ESM or an increase in the stipulated ROE of 9.4 percent to alleviate these inequities. (*Id.*) NPC notes that whether the risk materializes is not relevant; rather, the appropriate consideration is the existence of a risk which warrants an upward adjustment to the allowed return on equity. (*Id.*) NPC states that the

issues created by continuing the ESM provide another reason why a more thorough discussion in Docket No. 19-06008 is necessary to address the current mechanism's inequities. (*Id.*)

53. NPC states that SNGG's argument[11] for an asymmetrical ESM is based simply on the following: (1) NPC can file for a rate increase if it is under-earning; (2) NPC can over-earn by controlling its cost structure; (3) customers do not have the ability to force a show-cause proceeding or initiate a rate case; and, (4) there is a pandemic; therefore, NPC should continue to be subject to an ESM. (*Id.* at 11-12.)

54. NPC states that the first argument contains several flaws. (*Id.* at 12.) NPC notes that it takes approximately five months to prepare and 210 days to complete a general rate review; thus, any new rates would take effect nearly two years after NPC under-earned, failing to compensate NPC for the under-earnings over those two years. (*Id.*)

55. NPC states that SNGG's second argument is also flawed. (*Id.*) NPC states that it certainly controls its cost structure, but this is neither a risk nor a detriment to customers. (*Id.*) NPC notes that the mandated triennial rate filing limits the upside benefit to NPC of cost reductions and ensures that customers benefit from the lower cost structure in a timely manner. (*Id.*)

56. NPC states that the third argument, a customer's inability to affect rates between rate cases, also lacks merit. (*Id.*) NPC states that subsections 3 and 4 of NRS 704.120 address a customer complaint of one or more rates. (*Id.*) NPC explains that, in contrast, subsection 5 allows the Commission to investigate and change any rate on its own motion. (*Id.*) NPC states that it is puzzling what possible meaning SNGG is attributing to NRS 704.120 as a whole, and subsections 3 and 4 specifically, to read it as precluding a customer from making a filing with the

[11] Ex. 1001, Direct Testimony of Larry Blank at 6-7, Q/A 7.

Commission to change rates. (*Id.* at 12-13.) NPC states that the statute unambiguously provides this protection to customers. (*Id.* at 13.)

57. NPC states that SNGG's fourth argument, arbitrarily using NPC to provide pandemic assistance, is equally perplexing. (*Id.*) NPC states that this logic's implication suggests that all Nevada utilities should be subject to an ESM to benefit Nevada citizens. (*Id.*) NPC states that COVID-19's impact on Nevada residents and the economy is unfortunate; nevertheless, the existence of COVID-19 does not support the continuation of the ESM. (*Id.*)

58. NPC states that, in Docket Nos. 17-06003 and 17-06004, the assertion of overearnings was based, in part, on the quarterly earned rate of return and return on equity reports filed with the Commission.[12] (*Id.*) NPC asserts that these reports' inability to accurately measure NPC's returns was addressed in Docket Nos. 17-06003 and 17-06004 and the Commission recognized the shortcomings of these reports by instructing parties to work together to develop a new methodology that accurately measures returns and overearnings.[13] (*Id.* at 13-14.) NPC states that the parties worked collaboratively and developed a new methodology that more accurately measures returns. (*Id.* at 14.)

59. NPC notes that, interestingly, SNGG also relies on the same rate of return reports, as did MGM in Docket Nos. 17-06003 and 17-06004, as justification for the continuation of the ESM.[14] (*Id.*) NPC states that the Commission declined to find that these rate of return reports fairly represent NPC's returns and should be used in determining overearnings.[15] (*Id.*) NPC

[12] Administrative notice taken of Docket Nos. 17-06003 and 17-06004, Direct Testimony of Dennis E. Peseau at 3-4, Q/A6.
[13] Docket Nos. 17-06003 and 17-06004, December 19, 2018, Modified Final Order at 116, para. 475.
[14] Exhibit 1001, Direct Testimony of Larry Blank at 5-6.
[15] *See, e.g.*, Docket Nos. 17-06003 and 17-06004, December 19, 2018, Modified Final Order at 116, para. 475.

states that, therefore, SNGG's reference to these reports as support for the continuation of the ESM is of questionable value. (*Id.*)

60. NPC states that assuming an ESM is even warranted, these types of discussions surrounding the mechanics of an ESM are best addressed in rulemaking dockets such as Docket No. 19-06008. (*Id.* at 17.)

61. NPC states that the Commission's Order in Docket Nos. 17-06003 and 17-06004 clearly states that the annual DEAA "proceeding is the proper forum for determining whether, when and in what amount Nevada Power is earning in excess of the ROE approved by the PUCN."[16] (*Id.* at 17-18.)

Commission Discussion and Findings

62. Pursuant to NRS 704.001(4), the Commission must "balance the interests of customers and shareholders of public utilities by providing public utilities with the opportunity to earn a fair return on their investments while providing customers with just and reasonable rates".

63. The Commission notes that, pursuant to paragraph 49 of the Stipulation and in accordance with the notice issued on October 1, 2020, the Commission has two options with respect to the ESM in this docket. First, to discontinue the ESM for NPC effective December 31, 2020, or, second, to continue the ESM as ordered in NPC's prior GRC, Docket No. 17-06003.

64. NPC and Staff recommend that the ESM be discontinued in its current form and any future changes with regard to an ESM mechanism be addressed within the framework of SB 300 and the attendant investigation and rulemaking in Docket No. 19-06008. SNGG also acknowledges that Docket No. 19-06008 is the place for making any changes to the ESM, although in the context of continuing the current mechanism.

[16] Docket Nos. 17-06003 and 17-06004, December 19, 2018, Modified Final Order at 114, para. 468.

65. The Commission agrees with BCP that the ESM not only preserves the incentive for the utility to institute cost-cutting measures but it also protects ratepayers against excessive over-earnings by the utility that could result from these cost-cutting measures between rate cases. As noted by SNGG, the Commission approved an earnings-sharing mechanism for SPPC in Docket No. 19-06002[17] shortly after passage of SB 300. As further noted by SNGG, the earnings-sharing mechanism provides considerable customer protection, especially during economic uncertainty related to the ongoing COVID-19 pandemic. SNGG notes that the current pandemic weighs in favor of retaining the ESM. The Commission agrees that customers would receive protection from maintaining the ESM during this rate cycle beginning on January 1, 2021.

66. Those who recommend discontinuation rely, in part, on the ongoing rulemaking in Docket No. 19-06008. The Commission agrees that Docket No. 19-06008 is where an in-depth discussion of the complexities of an ESM should take place. The evidence presented by SNGG and BCP in this proceeding indicates that continuing the ESM in its current state is just and reasonable compared to completely eliminating the ESM and the protection that it affords to consumers, especially given that the ESM still allows NPC to retain a significant majority of its excess earnings. The Commission finds, therefore, that there shall be a continuation of the ESM ordered in Docket No. 17-06003. NPC shall retain 100 percent of its earnings in excess of its authorized return on equity of 9.40 percent up to 9.70 percent. Any earnings in excess of 9.70 percent shall be shared 50/50 between ratepayers and the utility.

67. The Commission agrees that it will be beneficial to evaluate an ESM in the context of an alternative ratemaking plan. However, given the timing of when such a plan could

[17] The Modified Final Order in Docket No. 19-06002 approved a Stipulation by the parties to an earnings sharing mechanism to be tracked and reported in the same manner as for NPC.

be filed for approval and the fact that NPC is not required to file an alternative ratemaking plan at all, the Commission declines to cease the current earnings-sharing paradigm pending the outcome of any alternative ratemaking proceeding. NPC's ESM may be modified as applicable should an alternative rate plan including an ESM be approved prior to December 31, 2023. Therefore, the Commission will address this mechanism as part of the ongoing rulemaking in Docket No. 19-06008 and in subsequent rate proceedings, as appropriate.

68. NPC has expressed concern with the fact that the current ESM is asymmetrical and that there is no corresponding mechanism should NPC not achieve its authorized ROE of 9.40 percent. The Commission finds this concern to be mitigated by the structure of the continued ESM. NPC retains all earnings up to an ROE of 9.70 percent, and 50 percent of all earnings in excess of that amount.

69. The Commission finds that, with respect to the annual DEAA filing, that portion of the ESM to be adjudicated within the annual DEAA filing shall be limited to proposed changes to the calculation methodology and verification that the calculation methodology was accurately applied in the calculation of the annual amount recorded in the regulatory liability account, if applicable.

70. The Commission acknowledges the work of the parties in Docket No. 19-03001 to come to the stipulated agreement regarding the ESM calculation methodology. However, it would be unreasonable to find that, over time and experience, changes to that calculation methodology should not be proposed and evaluated. Any changes would best be established as part of an alternative ratemaking process; however, until such time as an alternative ratemaking plan is submitted by NPC, any changes proposed to the calculation methodology shall be made in the annual DEAA filing.

71. Likewise, the annual DEAA filing is the appropriate forum in which to verify the application of the ESM calculation methodology on a strictly mathematical basis. This is necessary to establish the potential annual regulatory liability amount for future review purposes.

72. The Commission finds that the verification and vetting of the amounts recorded in the accounts used in the calculation of the earnings-sharing regulatory liability shall be performed in NPC's next GRC application.

73. The revenues and expenses used in the calculation of the earnings-sharing regulatory liability are related to GRC revenues and expenses. The Commission acknowledges the difficulty this presents to parties in performing verification of the potential three years' underlying activity in the accounts that are used in the calculation of any excess earnings. The Commission therefore encourages verification, to the extent possible, of the amounts in the annual DEAA filing. To some degree, this is similar to the review of other regulatory assets or regulatory liabilities which may have been established, such as those created pursuant to the Emissions Reduction and Capacity Replacement statutes and regulations in the past.

THEREFORE, it is ORDERED:

1. The initial Interim Order and Interim Order No. 2, wherein the Stipulation filed by Nevada Power Company d/b/a NV Energy; the Regulatory Operations Staff of the Commission; the Nevada Bureau of Consumer Protection; MGM Resorts International, Caesars Enterprise Services LLC; the Southern Nevada Gaming Group;[18] Wynn, Las Vegas, LLC; Circus Circus Las Vegas, LLC; the Smart Energy Alliance; the Kroger Co.; Walmart, Inc.; Nevada Cogeneration Associates #1; Sunrun, Inc; and the Colorado River Commission of Nevada,

[18] Southern Nevada Gaming Group consists of the Boyd Gaming Corporation, Las Vegas Sands Corp., Stations Casinos LLC, Plaza Hotel and Casino, LLC, Tropicana Las Vegas Inc., and LVGV, LLC.

appended hereto as Attachment 1, are subsumed within this order, and the Stipulation is ACCEPTED.

2. The Application of Nevada Power Company d/b/a NV Energy designated as Docket No. 20-06003, is GRANTED IN PART, as modified by the Stipulation and this order. Nevada Power Company d/b/a NV Energy shall continue the earnings-sharing mechanism ordered in Docket No. 17-06003, subject to any modifications made to the earnings-sharing mechanism pursuant to Senate Bill 300 and the attendant investigation and rulemaking in Docket No. 19-06008. The earnings-sharing mechanism will be reviewed within the annual Deferred Energy Accounting Adjustment filing, with proposed changes limited to the calculation methodology and verification that the calculation methodology was accurately applied in the calculation of the annual amount recorded in the regulatory liability account, if applicable.

Directives

3. All cost-of-service studies filed by Nevada Power Company d/b/a NV Energy in its next general rate case shall include one version with generation and energy costs separately reconciled. Nevada Power Company d/b/a NV Energy may include a cost-of-service study or studies with its generation and energy combined using the generation and energy allocator and must provide detailed testimony supporting the use of the generation and energy allocator should it choose to do so.

4. Nevada Power Company d/b/a NV Energy shall file in its next general rate case application a complete embedded cost-of-service study with enough detail to allow for transparent review and vetting by the parties, to include the results of the embedded cost allocators discussion pursuant to paragraph 45 of the Stipulation. Nevada Power Company d/b/a NV Energy shall, not later than January 5 of the year in which it files its next general rate case,

meet with the Regulatory Operations Staff of the Commission, the Nevada Bureau of Consumer Protection, and other interested stakeholders to discuss embedded cost allocators.

5. Nevada Power Company d/b/a NV Energy shall file in its next general rate case application a complete hybrid cost-of-service study using the Regulatory Operations Staff of the Commission's methodology with enough detail to allow for transparent review and vetting by the parties and Commission.

6. Nevada Power Company d/b/a NV Energy shall file in its next general rate case a detailed analysis of its evaluation process for the marginal unit used in its marginal cost-of-service study.

7. Nevada Power Company d/b/a NV Energy shall update its time-of-use periods in its next general rate case.

8. Nevada Power Company d/b/a NV Energy shall use the weather normalization methodology adopted in Sierra Pacific Power Company d/b/a NV Energy's 2019 rate case.

9. Nevada Power Company d/b/a NV Energy shall convene an ad hoc interconnection working group open to all interested stakeholders, with a goal of gaining process efficiencies and cost reductions. The topics for discussion shall include process improvements and cost reductions for interconnections that involve main panel upgrades, energy storage, and other issues as they arise. Nevada Power Company d/b/a NV Energy and stakeholders shall jointly petition the Commission to seek any necessary approvals to implement agreed-upon process changes, as appropriate. In the event that Nevada Power Company d/b/a NV Energy and stakeholders disagree regarding any interconnection issue addressed in the working group, Nevada Power Company d/b/a NV Energy and stakeholders shall, on an annual basis but only if necessary, jointly petition the Commission to seek formal resolution.

10. Nevada Power Company d/b/a NV Energy shall engage in good faith negotiations with the Colorado River Commission of Nevada prior to April 1, 2021, to discuss modifications to the Hoover D tariff that is scheduled to change January 1, 2022.

By the Commission,

HAYLEY WILLIAMSON, Chair

C.J. MANTHE, Commissioner and Presiding Officer

Attest: TRISHA OSBORNE,
Assistant Commission Secretary

Dated: Carson City, Nevada

12/10/20

(SEAL)

PUBLIC UTILITIES COMMISSION OF NEVADA
PUC

ATTACHMENT 1

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

In the Matter of the Application by **NEVADA POWER COMPANY D/B/A NV ENERGY,** filed pursuant to NRS 704.110(3) and NRS 704.110(4), addressing its annual revenue requirement for general rates charged to all classes of electric customers.	Docket No. 20-06003

STIPULATION

Pursuant to Nevada Administrative Code ("NAC") §§ 703.750 and 703.845, Nevada Power Company, d/b/a NV Energy ("NV Energy," "Nevada Power," or "Company"), the Regulatory Operations Staff ("Staff") of the Public Utilities Commission of Nevada ("Commission"), the Office of the Attorney General's Bureau of Consumer Protection ("BCP"), Walmart, the Kroger Co. ("Kroger"), Colorado River Commission of Nevada ("CRCNV"), Nevada Cogeneration Associates ("NCA"), Sunrun Inc. ("Sunrun"), MGM Resorts International ("MGM"), Caesars Enterprise Services, LLC ("Caesars"); Wynn Las Vegas LLC ("Wynn"), Circus Circus Las Vegas ("Circus Circus"), LLC, Smart Energy Alliance ("SEA"), and Southern Nevada Gaming Group ("SNGG")[1] each individually a "Signatory" and together the "Signatories," enter into this Stipulation to resolve all but one issue related to the Company's Application for Authority to Adjust Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers ("Application").

SUMMARY OF STIPULATION

The Signatories agree this Stipulation provides a reasonable resolution of issues raised in the Application and that the Stipulation is in the public interest. Specifically, through the Stipulation the Company will issue a $120 million one-time bill credit to customers, utilize a ROE of 9.4% and a total revenue requirement of $1.0702 billion, and make certain agreed upon adjustments to rates and fees. A determination whether to continue the earnings sharing

[1] Boyd Gaming Corporation, Station Casinos LLC, Las Vegas Sands, Plaza Hotel and Casino, LLC, Tropicana Las Vegas Inc., and LVGV, LLC are collectively SNGG.

Nevada Power Company
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mechanism ordered in Docket No. 17-06003 will be resolved via a limited hearing before the Commission.

The Stipulation only settles issues related to this docket. The Stipulation only seeks relief the Commission is empowered to grant. Accordingly, the Signatories recommend the Commission accept the Stipulation.

RECITALS

1. On June 1, 2020, the Company filed its Application.

2. On June 8, 2020, the Commission issued a Notice of Application.

3. On June 9, 2020, the Commission issued a Notice of Prehearing Conference and the BCP filed a Notice of Intent to Intervene pursuant to NRS Chapter 228.

4. Staff participates as a matter of right pursuant to NRS 703.301.

5. On June 12, 2020, Walmart filed a Petition for Leave to Intervene ("PLTI").

6. On June 17, 2020, Kroger filed a PLTI, Motion for Admission Pro Hac Vice, and Notice of Association of Counsel.

7. On June 29, 2020, CRCNV filed a PLTI.

8. On June 30, 2020, NCA, MGM, Caesars, and Sunrun each filed PLTIs.

9. On July 1, 2020, Wynn, Circus Circus, and SEA (collectively, "WCS"), filed a joint PLTI and a Notice of appearance, and the SNGG filed a PLTI.

10. On July 9, 2020, the Commission held a prehearing conference. The Company, Staff, BCP, Caesars, CRCNV, Kroger, MGM, NCA, SNGG, Sunrun, Walmart, and WCS appeared and discussed a procedural schedule and the PLTIs.

11. On July 15, 2020, the Commission issued a Procedural Order.

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12. On July 16, 2020, the Commission issued a Notice of Consumer Session and Notice of Hearing, and an Order granting the PLTIs of Caesars, CRCNV, Kroger, MGM, NCA, SNGG, Sunrun, Walmart, and WCS.

13. On July 21, 2020, the Staff and BCP filed the Joint Motion and Order Shortening Time.

14. On July 22, 2020, the Company filed a Response to the Joint Motion's request for an Order Shortening Time, Staff and BCP filed a Joint Reply to the Company's Response, and the Commission issued an Order denying the Movant's request for an Order Shortening Time.

15. On July 28, 2020, Caesars and MGM, the Company, and WCS filed Responses to the Joint Motion.

16. On August 3, 2020, the Staff and BCP filed a Joint Reply and the Company submitted its Cost of Capital certification filing.

17. On August 7, 2020, the Commission issued an order denying the Joint Motion, Procedural Order No. 3 establishing a schedule for an evidentiary hearing, and Notice of Hearing.

18. On August 13, 2020, the Commission issued a Notice of Prehearing Conference and Procedural Order No. 4.

19. On August 17, 2020, Kroger, WCS, BCP, SNGG, MGM, Caesars, and Staff filed testimony pursuant to Procedural Order No. 3. Also, on August 17, 2020, the Company submitted its Revenue Requirement certification filing pursuant to Procedural Order No. 3.

20. On August 26, 2020, the Company filed its rebuttal testimony.

21. On August 27, 2020, the Commission issued Procedural Order No. 5.

22. On August 28, 2020, the Company submitted its Rate Design certification filing.

23. On August 31, 2020, the Company filed information responsive to Procedural Order No. 5, paragraphs 24-25.

24. On September 1, 2020, the Commission held an evidentiary hearing, and the Company filed additional information responsive to paragraph 26 of Procedural Order No. 5. Also on September 1, 2020, an Overearnings Credit Allocation Stipulation was filed by Kroger, WCS, BCP, SNGG, MGM, Caesars, Walmart, CRC NV, and Staff.

25. On September 4, 2020, Staff, BCP, MGM, Caesars, and WCS filed Cost of Capital testimony.

26. On September 9, 2020, the Commission issued its Interim Order ordering the Company to return $59,675,474.00 of the Earnings Sharing Regulatory Liability in the form of a one-time bill credit. The Commission also issued Procedural Order No. 6.

27. On September 16, 2020, the Company filed information in compliance with Procedural Order No. 6.

28. On September 18, 2020, the Company filed its Cost of Capital rebuttal testimony.

29. On September 22, 2020, the Commission issued Procedural Order No. 7.

<u>**AGREEMENT OF THE SIGNATORIES**</u>

NOW THEREFORE, in light of the foregoing considerations, the Signatories agree and recommend that the Commission approve the stipulation as follows:

Cost of Capital and Revenue Requirement

30. The Company shall issue a $120 million one-time bill credit to be immediately distributed to customers based on the calculation of recorded rate base tariff general rate

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("BTGR") revenues using non-normalized billing determinants for calendar year 2019. The one-time bill credit includes: 1) the $59.7 million earnings sharing regulatory liability as ordered by the Commission in the September 9 Interim Order; 2) $26 million from the unprotected excess accumulated deferred income tax ("ADIT") regulatory liability; 3) expected earnings sharing for 2020 of $20 million, which will act as a reduction to the 2020 over earnings balance accepted by the Commission in future proceedings; and 4) approximately $9 million in carrying charges on the earnings sharing regulatory liability that accrued during calendar years 2019 and 2020, and 5) approximately $5 million in other expense adjustments. The final class allocations of the credit amounts are presented in Exhibit 1 ("Settlement One-Time Credit Allocation").

a. BTGR revenues will include impact fee revenues for distribution-only service ("DOS") customers consistent with "Present" BTGR revenues for 2019 as presented in Statements J and O in the original application.

b. A proportionate allocation to each rate schedule would result in each rate schedule receiving an equal percentage credit applicable to each rate schedule's recorded 2019 BTGR revenues.

c. For rate schedules serving large non-residential customers (LGS-2, LGS-3, LGS-X, LGS-2-DOS, LGS-3-DOS, LGS-X-DOS) the overearnings refund will be based directly on the total recorded BTGR revenue contributed by each such large customer by meter during calendar year 2019. Using this method, the meter-specific refund would apply the equal percentage credit to the BTGR revenues attributable to each large-customer meter in 2019.

d. If the final calculation of the 2020 overearnings is less than $20 million, the Company will not seek recovery from customers of any of the $20 million representing the 2020 overearnings. If the final calculation of the 2020 overearnings is more than $20 million, such amount will be due to ratepayers consistent with the Order in Docket No. 17-06003 or other applicable Commission Order.

31. The Company's return on equity ("ROE") will be set at 9.4 percent and the rate of return ("ROR") will be set at 7.14 percent.

32. The Company's total revenue requirement will be set at $1.0702 billion, which reflects: 1) the Company's expected change in circumstance ("ECIC") adjustments; 2) Staff's weather normalization adjustment; 3) the $59.7 million of 2018 and 2019 earnings sharing regulatory liability as part of the $120.0 million one-time credit; 4) $26.0 million of unprotected ADIT regulatory liability as part of the $120.0 million one-time credit; 5) a 9.4 percent ROE; and 6) a "black box" settlement revenue requirement adjustments for other adjustments needed to get the Company's filing to stipulated revenue requirement amount.

33. Cost recovery associated with the Reid Gardner and Navajo power plants is incorporated into the revenue requirement as proposed by Nevada Power such that there is no impairment of cost recovery relative to Nevada Power's filing. This includes regulatory asset balance of $112.4 million in decommissioning and remediation costs for Reid Gardner per I-CERT-30, regulatory asset and balance credit of $1.65 million for Navajo per I-CERT-31, and regulatory asset balance of $0.678 million per I-CERT-28 for Mohave. These costs are to be recovered over the period 2021-2023 as reflected in the filing and are approved by all parties. Future additional costs incurred by Nevada Power regarding these facilities will be included as part of future general rate case proceedings. All parties reserve their rights to review and make recommendations regarding recovery of future costs, and whether and how the costs should be allocated to all customers in future general rate case proceedings.

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34. The Company agrees to a tiered interconnection fee that provides for a lower fee for smaller distributed generation ("DG") systems and a higher fee for larger DG systems, instead of the averaged fee currently proposed for all DG systems. The tiered interconnection fees are provided in Exhibit 2.

35. NV Energy agrees to convene an ad hoc interconnection working group open to all interested stakeholders, with a goal to gain process efficiencies and cost reductions. The working group will convene at the request of any stakeholder on an as-needed basis. Topics for discussion shall include process improvements and cost reductions for interconnections that involve main panel upgrades, energy storage and other issues as they arise. NV Energy agrees to jointly petition the Commission along with stakeholders to seek any necessary approvals to implement agreed-upon process changes, as appropriate. In the event NV Energy and stakeholders disagree regarding any interconnection issue addressed in the working group, NV Energy agrees, on an annual basis and if necessary, to jointly petition with the Commission to seek formal resolution.

36. The Company commits to engaging in good faith negotiations with the CRCNV prior to April 1, 2021, to discuss modifications to the Hoover D tariff that is scheduled to change January 1, 2022.

Rate Design

37. The Company's rate design will use Staff's trend weather normalization methodology that the Commission adopted in Sierra Pacific Power Company's ("SPPC") 2019 rate case.

38. The Company's rate design will use Generation Allocators, not Generation & Energy Allocators, which the Commission adopted to allocate generation demand costs in SPPC's 2019 rate case.

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39. The Company's rate design will not include energy costs (BTER) in adjusting class revenue requirement for policy considerations in Statement O, Tab "Passes." More broadly, while it is acceptable to list energy costs (BTER) in Cost of Service Study and Statement O, they should not be used in any BTGR calculations or "Interclass Revenue Adjustments."

40. The Company's rate design will not shift all claimed net metering ("NEM") revenue shortfalls to the corresponding otherwise applicable class (e.g., NMR schedules to RS schedule), which inflates Nevada Power's calculated subsidy for the corresponding otherwise applicable class (e.g., RS).

41. The Company's rate design will use Exhibit Pollard Cert-20, Statement O-ECS-E Proposed Revenue Requirement-Proposed Rates, as adjusted and proposed in Exhibit 3 ("Settlement Statement O"). In the event of any ambiguity or perceived divergence between the language of this Stipulation and the rates identified in Exhibit 3, Exhibit 3 will control.

42. The Signatories agree to accept the rates contained in Exhibit 3 (Settlement Statement O) as the tariffed rates effective January 1, 2021.

43. When the claimed NEM revenue shortfalls are placed back to its appropriate rate class (e.g., from RS to RS-NEM and RM to RM-NEM), Exhibit Settlement Statement O shows that there is no subsidy for non-NEM residential customers.

44. The Company's embedded cost of service study filed in this general rate case used marginal cost allocators, and such allocators are not generally accepted in embedded cost-of-service studies used in other state jurisdictions.

45. Not later than January 5 of the year in which NPC files its next general rate case, NVE agrees to meet with Staff, BCP, and interested interveners to discuss embedded cost allocators to be used in an embedded cost of service study that will be filed in Nevada Power's

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next general rate case. Nevada Power will notify the Signatories of such meeting(s) reasonably in advance to provide the Signatories an opportunity to participate.

46. Nevada Power agrees to make the following changes to the LGS-2S schedule rates:

a. Adjust the On Peak Generation Demand per kW charge to $12.81 and increase the Mid Peak Generation Demand per kW charge to $2.65.

b. Commensurately decrease the On Peak, Mid Peak, Off Peak, and Other time-of-use ("TOU") energy per kWh charges so that the net impact is revenue neutral to the Company, while also maintaining the Company's proposed ratios between the TOU energy charges.

47. Nevada Power will provide an updated review of TOU periods in its next general rate case.

48. The Parties agree that NPC has complied with Directive 20 in the Commission's Modified Final Order in Docket No. 19-06002 to review its TOU periods.

Continuation of the Earnings Sharing Mechanism

49. The issue of whether there should be a continuation of the earnings sharing mechanism ordered in Docket No. 17-06003 will be resolved via a limited hearing on October 12, 2020, at 10:00 am.

50. Staff, BCP, SNGG and Nevada Power will file testimony and participate in a hearing pursuant to the following schedule:

a. Staff, BCP, SNGG testimony to be filed on September 24, 2020, by 2:00 PM.

b. Nevada Power rebuttal testimony to be filed on October 6, 2020, by 2:00 PM.

c. Hearing to be held on October 12, 2020, at 10:00 am.

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d/b/a NV Energy

51. All other Signatories have agreed to not file testimony and have waived their right to perform cross examination of any witness during the hearing on October 12, 2020.

52. Nothing in this stipulation shall be construed to prevent any party from addressing earnings sharing in Docket No. 19-06008 (Rulemaking for Senate Bill 300—Alternative Ratemaking), or future general rate review proceedings.

ADIT

53. As part of this stipulation NVE agrees to withdraw its Appeal filed with the Nevada Supreme Court (Case No. 81154, regarding the ADIT tax issues).

<u>GENERAL PROVISIONS</u>

A. This Stipulation shall not serve as precedent for the resolution of any issue in the future by the Commission, with the exception of the matters enumerated herein and the findings that follow.

B. In accordance with NAC § 703.845, this Stipulation settles only issues relating to the present proceeding and seeks relief that the Commission is empowered to grant.

C. This Stipulation is entered into for the purpose of resolving all but one issue in this Docket by and among the Signatories as set forth above. This Stipulation is made upon the express understanding that it constitutes a negotiated settlement. The provisions of this Stipulation are not severable.

D. This Stipulation represents a compromise of the positions of the Signatories. As such, conduct, statements and documents disclosed in the negotiation of this Stipulation shall not be admissible as evidence in this Docket or any other proceeding. Except as set forth herein, neither this Stipulation, nor its terms, nor the Commission's acceptance or rejection of the terms contained in this Stipulation shall have any precedential effect in future proceedings.

E. Except as otherwise modified by the stipulation, the requests contained in the application will be deemed approved as filed.

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

F. This Stipulation may be executed in one or more counterparts, all of which together shall constitute the original executed document. This Stipulation may be executed by Signatories by electronic transmission, which signatures shall be as binding and effective as original signatures.

[Signature pages to follow]

Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy

This Stipulation is entered into by each Signatory as of the date entered below:

NEVADA POWER COMPANY
d/b/a NV ENERGY

Date

By: Michael Greene, Esq.
Deputy General Counsel

REGULATORY OPERATIONS STAFF OF THE PUBLIC UTILITIES COMMISSION OF NEVADA

Date

By: Shelly Cassity, Esq.
Assistant Staff Counsel
Jesse Panoff, Esq.
Assistant Staff Counsel

BUREAU OF CONSUMER PROTECTION

Date

By: Michael Saunders, Esq.
Senior Deputy Attorney General

MGM RESORTS INTERNATIONAL

Date

By: Fred Schmidt, Esq.
Austin Jensen, Esq.

CAESARS ENTERPRISE SERVICES

Date

By: Fred Schmidt, Esq.
Austin Jensen, Esq.

SOUTHERN NEVADA GAMING GROUP

Date

By: Lucas Foletta, Esq.

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

This Stipulation is entered into by each Signatory as of the date entered below:

NEVADA POWER COMPANY
d/b/a NV ENERGY

Date

By: Michael Greene, Esq.
Deputy General Counsel

REGULATORY OPERATIONS STAFF OF THE PUBLIC UTILITIES COMMISSION OF NEVADA

9/24/20

Date

By: Shelly Cassity, Esq.
Assistant Staff Counsel
Jesse Panoff, Esq.
Assistant Staff Counsel

BUREAU OF CONSUMER PROTECTION

Date

By: Michael Saunders, Esq.
Senior Deputy Attorney General

MGM RESORTS INTERNATIONAL

Date

By: Fred Schmidt, Esq.
Austin Jensen, Esq.

CAESARS ENTERPRISE SERVICES

Date

By: Fred Schmidt, Esq.
Austin Jensen, Esq.

SOUTHERN NEVADA GAMING GROUP

Date

By: Lucas Foletta, Esq.

This Stipulation is entered into by each Signatory as of the date entered below:

NEVADA POWER COMPANY
d/b/a NV ENERGY

Date ______________________

By: Michael Greene, Esq.
Deputy General Counsel

REGULATORY OPERATIONS STAFF OF THE PUBLIC UTILITIES COMMISSION OF NEVADA

Date ______________________

By: Shelly Cassity, Esq.
Assistant Staff Counsel
Jesse Panoff, Esq.
Assistant Staff Counsel

BUREAU OF CONSUMER PROTECTION

September 24, 2020
Date

By: Michael Saunders, Esq. 20-06003
for Senior Deputy Attorney General

MGM RESORTS INTERNATIONAL

Date ______________________

By: Fred Schmidt, Esq.
Austin Jensen, Esq.

CAESARS ENTERPRISE SERVICES

Date ______________________

By: Fred Schmidt, Esq.
Austin Jensen, Esq.

SOUTHERN NEVADA GAMING GROUP

Date ______________________

By: Lucas Foletta, Esq.

Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy

This Stipulation is entered into by each Signatory as of the date entered below:

NEVADA POWER COMPANY
d/b/a NV ENERGY

Date ______ By: Michael Greene, Esq.
Deputy General Counsel

REGULATORY OPERATIONS STAFF OF THE PUBLIC UTILITIES COMMISSION OF NEVADA

Date ______ By: Shelly Cassity, Esq.
Assistant Staff Counsel
Jesse Panoff, Esq.
Assistant Staff Counsel

BUREAU OF CONSUMER PROTECTION

Date ______ By: Michael Saunders, Esq.
Senior Deputy Attorney General

MGM RESORTS INTERNATIONAL

9-24-20 Fred Schmidt
Date ______ By: Fred Schmidt, Esq.
Austin Jensen, Esq.

CAESARS ENTERPRISE SERVICES

9-24-20 Fred Schmidt
Date ______ By: Fred Schmidt, Esq.
Austin Jensen, Esq.

SOUTHERN NEVADA GAMING GROUP

Date ______ By: Lucas Foletta, Esq.

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

	WYNN LAS VEGAS, LLC, CIRCUS CIRCUS LAS VEGAS, LLC, AND SMART ENERGY ALLIANCE
September 24, 2020 Date	By: Curt Ledford, Esq. Tyler Pepple, Esq.
	THE KROGER CO.
Date	By: Kurt Boehm, Esq.
	WALMART
Date	By: Vicki Baldwin, Esq.
	COLORADO RIVER COMMISSION
Date	By: Christine Guerci Nyhus, Esq.
	SUNRUN, INC
Date	By: Kevin Fox, Esq. Jacob Schlesinger, Esq.
	NEVADA COGENERATION ASSOCIATES
Date	By: Donald Brookhyser

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

WYNN LAS VEGAS, LLC, CIRCUS CIRCUS LAS VEGAS, LLC, AND SMART ENERGY ALLIANCE

Date ______________________ By: Curt Ledford, Esq.
Tyler Pepple, Esq.

THE KROGER CO.

9.24.20
Date ______________________ By: Kurt Boehm, Esq.

WALMART

Date ______________________ By: Vicki Baldwin, Esq.

COLORADO RIVER COMMISSION

Date ______________________ By: Christine Guerci Nyhus, Esq.

SUNRUN, INC

Date ______________________ By: Kevin Fox, Esq.
Jacob Schlesinger, Esq.

NEVADA COGENERATION ASSOCIATES

Date ______________________ By: Donald Brookhyser

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

WYNN LAS VEGAS, LLC, CIRCUS CIRCUS LAS VEGAS, LLC, AND SMART ENERGY ALLIANCE

Date ____________________

By: Curt Ledford, Esq.
Tyler Pepple, Esq.

THE KROGER CO.

Date ____________________

By: Kurt Boehm, Esq.

WALMART

Date ____________________

By: Vicki Baldwin, Esq.

COLORADO RIVER COMMISSION

Date ____________________

By: Christine Guerci Nyhus, Esq.

SUNRUN, INC

Date ____________________

By: Kevin Fox, Esq.
Jacob Schlesinger, Esq.

NEVADA COGENERATION ASSOCIATES

Date ____________________

By: Donald Brookhyser

WYNN LAS VEGAS, LLC, CIRCUS CIRCUS LAS VEGAS, LLC, AND SMART ENERGY ALLIANCE

Date

By: Curt Ledford, Esq.
Tyler Pepple, Esq.

THE KROGER CO.

Date

By: Kurt Boehm, Esq.

WALMART

Date

By: Vicki Baldwin, Esq.

COLORADO RIVER COMMISSION

9/24/2020
Date

By: Christine Guerci Nyhus, Esq.

SUNRUN, INC

Date

By: Kevin Fox, Esq.
Jacob Schlesinger, Esq.

NEVADA COGENERATION ASSOCIATES

Date

By: Donald Brookhyser

WYNN LAS VEGAS, LLC, CIRCUS CIRCUS LAS VEGAS, LLC, AND SMART ENERGY ALLIANCE

Date ______________________ By: Curt Ledford, Esq.
Tyler Pepple, Esq.

THE KROGER CO.

Date ______________________ By: Kurt Boehm, Esq.

WALMART

Date ______________________ By: Vicki Baldwin, Esq.

COLORADO RIVER COMMISSION

Date ______________________ By: Christine Guerci Nyhus, Esq.

SUNRUN, INC

9/24/2020
Date ______________________ By: Kevin Fox, Esq.
Jacob Schlesinger, Esq.

NEVADA COGENERATION ASSOCIATES

Date ______________________ By: Donald Brookhyser

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

Date	By: Kurt Boehm, Esq.
	WALMART
Date	By: Vicki Baldwin, Esq.
	COLORADO RIVER COMMISSION
Date	By: Christine Guerci Nyhus, Esq.
	SUNRUN, INC
Date	By: Kevin Fox, Esq. Jacob Schlesinger, Esq.
	NEVADA COGENERATION ASSOCIATES #1
Sept. 23, 2020 Date	By: Donald Brookhyser

EXHIBIT 1

Exhibit 1 – Earnings Sharing Credit Allocation

Line No.	Rate Schedule		Allocation: 2019 BTGR Revenue '$000 [1]	Allocation: Share of BTGR Revenue	Allocation: Bill Credit for Overearnings	Customer Count: Sml.-Med. Customer Recorded Bills [2]	Customer Count: Avg. Monthly Sml.-Med. Customer Recorded Bills [3]	Customer Count: December 2019 Counts	Earnings Sharing Credit: Sml.-Med. Credit/ Customer	Earnings Sharing Credit: Large Customer % Annual BTGR Credit
1	Residential - Single Family	RS	519,827	46.498%	55,797,824	6,278,240	523,187	520,255	$107.25	
2	Residential - Multi-Family	RM	150,590	13.470%	16,164,213	3,280,788	273,399	271,599	$59.51	
3	Residential - Large Single Family	LRS	2,302	0.206%	247,095	2,615	218	215	$1,149.28	
4	Residential - Single Family - Flexpay	RS-FLEX	506	0.045%	54,314	7,421	618	3,402	$15.97	
5	Residential - Multi-Family - Flexpay	RM-FLEX	442	0.040%	47,444	9,384	782	4,384	$10.82	
6	Residential - Single Family - Net Metering	RS-NEM	17,916	1.603%	1,923,089	440,908	36,742	50,974	$37.73	
7	Residential - Multi-Family - Net Metering	RM-NEM	89	0.008%	9,553	2,344	195	260	$36.74	
8	Residential - Large Single Family - Net Metering	LRS-NEM	29	0.003%	3,113	98	8	10	$311.28	
9	**Total Residential - Non-TOU**		691,701	61.872%	74,246,645	10,021,798	835,150	851,099		
10	Residential - Single Family - TOU	ORS-TOU	193	0.017%	20,716	2,752	229	314	$65.98	
11	Residential - Single Family - TOU - Net Metering	ORS-NEM	16	0.001%	1,717	547	46	159	$10.80	
12	Residential - Single Family - TOU - EVRR	ORS-TOU EVRR	567	0.051%	60,861	6,141	512	756	$80.50	
13	Residential - Single Family - TOU - EVRR - Net Metering	ORS-NEM EVRR	56	0.005%	6,011	1,561	130	327	$18.38	
14	Residential - Single Family - TOU Option A	ORS-TOU OPT A	1,725	0.154%	185,160	25,788	2,149	2,023	$91.53	
15	Residential - Single Family - TOU Option A - Net Metering	ORS-NEM OPT A	222	0.020%	23,829	6,632	553	584	$40.80	
16	Residential - Single Family - TOU Option A - EVRR	ORS-TOU OPT A EVRR	545	0.049%	58,500	6,179	515	472	$123.94	
17	Residential - Single Family - TOU Option A - EVRR Net Metering	ORS-NEM OPT A EVRR	52	0.005%	5,582	1,814	151	156	$35.78	
18	Residential - Single Family - TOU Option B	ORS-TOU OPT B	271	0.024%	29,089	3,646	304	279	$104.26	
19	Residential - Single Family - TOU Option B - Net Metering	ORS-NEM OPT B	10	0.001%	1,073	171	14	19	$56.49	
20	Residential - Single Family - TOU Option B - EVRR	ORS-TOU OPT B EVRR	250	0.022%	26,835	2,873	239	221	$121.42	
21	Residential - Single Family - TOU Option B - EVRR Net Metering	ORS-NEM OPT B EVRR	14	0.001%	1,503	200	17	20	$75.14	
22	Residential - Multi-Family - TOU	ORM-TOU	26	0.002%	2,791	693	58	85	$32.83	
23	Residential - Multi-Family - TOU - EVRR	ORM-TOU EVRR	21	0.002%	2,254	421	35	48	$46.96	
24	Residential - Multi-Family - TOU - EVRR - Net Metering	ORM-NEM EVRR	0	0.000%	0	5	0	2	$0.00	
25	Residential - Multi-Family - TOU Option A	ORM-TOU OPT A	69	0.006%	7,406	1,954	163	153	$48.41	
26	Residential - Multi-Family - TOU Option A - EVRR	ORM-TOU OPT A EVRR	7	0.001%	751	96	8	8	$93.92	
27	Residential - Multi-Family - TOU Option B	ORM-TOU OPT B	10	0.001%	1,073	250	21	19	$56.49	
28	Residential - Multi-Family - TOU Option B - EVRR	ORM-TOU OPT B EVRR	4	0.000%	429	111	9	9	$47.71	
29	Residential - Large Single Family - TOU - EVRR	OLRS-TOU EVRR	6	0.001%	644	13	1	1	$644.04	
30	**Total Residential - TOU**		4,064	0.364%	436,227	61,847	5,154	5,655		
31	**Residential - Private Area Lighting**	RS-PAL	46	0.004%	4,938	8,340	695	695	$7.10	
32	**Total Residential**		695,811	62.240%	74,687,809	10,091,985	840,999	857,449		
33	General Service - Non-TOU	GS	36,948	3.305%	3,965,969	884,736	73,728	74,879	$52.97	
34	General Service - Net Metering	GS-NEM	74	0.007%	7,943	1,216	101	118	$67.31	
35	General Service - TOU	OGS-TOU	1,207	0.108%	129,558	31,142	2,595	2,618	$49.49	
36	General Service - TOU EVRR	OGS-TOU EVRR	0	0.000%	0	8	1	1	$0.00	
37	General Service - Private Area Lighting	GS-PAL	155	0.014%	16,638	26,631	2,219	2,219	$7.50	
38	**Total General Service**		38,384	3.433%	4,120,109	943,733	78,644	79,835		
39	Large General Service - 1	LGS-1	173,311	15.503%	18,603,067	389,070	32,423	31,566	$589.34	
40	Large General Service - 1 - Net Metering	LGS-1 NEM	1	0.000%	107	6	1	5	$21.47	
41	Large General Service - 1 - SSR	SSR-III LGS-1	53	0.005%	5,689	48	4	4	$1,422.24	
42	Large General Service - 1 - TOU	OLGS-1 TOU	2,874	0.257%	308,493	3,582	299	327	$943.40	
43	**Total Large General Service - 1**		176,239	15.764%	18,917,357	392,706	32,726	31,902		
44	Large General Service - 2: Primary	LGS-2P	2,138	0.191%	229,491					10.73%
45	Large General Service - 2: Secondary	LGS-2S	87,098	7.791%	9,349,031					10.73%
46	Large General Service - 2: Transmission - LSR	LSR-I LGS-2T	66	0.006%	7,084					10.73%
47	Large General Service - 2: Secondary EVCCR	LGS-2S EVCCR	158	0.014%	16,960					10.73%
48	**Total Large General Service - 2**		89,460	8.002%	9,602,567					
49	Large General Service - 3: Primary	LGS-3P	42,601	3.811%	4,572,758					10.73%
50	Large General Service - 3: Secondary	LGS-3S	26,964	2.412%	2,894,295					10.73%
51	Large General Service - 3: Transmission	LGS-3T	4,370	0.391%	469,072					10.73%
52	Large General Service - 3: Primary - HLF	OLGS-3P-HLF	5,184	0.464%	556,447					10.73%
53	Large General Service - 3 MPE [4]	MPE LGS-3	0	0.000%	0					
54	Large General Service - 3: Primary - LSR	LSR-II LGS-3P	812	0.073%	87,159					10.73%

Exhibit 1 – Earnings Sharing Credit Allocation

Line No.	Rate Schedule		Allocation: 2019 BTGR Revenue '$000 [1]	Allocation: Share of BTGR Revenue	Allocation: Bill Credit for Overearnings	Customer Count: Sml.-Med. Customer Recorded Bills [2]	Customer Count: Avg. Monthly Sml.-Med. Customer Recorded Bills [3]	Customer Count: December 2019 Counts	Earnings Sharing Credit: Sml.-Med. Credit/ Customer	Earnings Sharing Credit: Large Customer % Annual BTGR Credit
55	Large General Service - 3: Transmission - LSR	LSR-II LGS-3T	2,495	0.223%	267,811					10.73%
56	**Total Large General Service - 3**		82,426	7.373%	8,847,542					
57	**Total Large General Service - 1, 2 & 3**		348,125	31.140%	37,367,466	392,706	32,726	31,902		
58	**Street Lighting**	SL	1,460	0.131%	156,715	7,224	7,224	7,224	$21.69	
59	LGS - Water Pumping -2: Primary	LGS-2P-WP	318	0.028%	34,134					10.73%
60	LGS - Water Pumping -2: Secondary	LGS-2S-WP	167	0.015%	17,926					10.73%
61	**Total LGS - Water Pumping - 2**		485	0.043%	52,060					
62	LGS - Water Pumping -3: Primary	LGS-3P-WP	210	0.019%	22,541					10.73%
63	LGS - Water Pumping -3: Secondary	LGS-3S-WP	21	0.002%	2,254					10.73%
64	**Total LGS - Water Pumping - 3**		231	0.021%	24,795					
65	**Total LGS - Water Pumping - 2 & 3**		716	0.064%	76,855					
66	**Total Bundled Non-Residential**		388,685	34.768%	41,721,144	1,343,663	111,972	118,961		
67	**Total - Bundled Classes**		1,084,496	97.007%	116,408,954	11,435,648	952,971	976,410		
68	General Service - DOS	GS DOS	5	0.000%	501	118	10	10	$50.08	
69	Large General Service - 1 - DOS	LGS-1 DOS	163	0.015%	17,450	251	21	21	$830.95	
70	Large General Service - 2: Primary - DOS	LGS-2P DOS	158	0.014%	16,946					10.73%
71	Large General Service - 2: Secondary - DOS	LGS-2S DOS	1,598	0.143%	171,491					10.73%
72	Large General Service - 3: Primary - DOS	LGS-3P DOS	16,678	1.492%	1,790,169					10.73%
73	Large General Service - 3: Secondary - DOS	LGS-3S DOS	2,357	0.211%	253,042					10.73%
74	Large General Service - 3: Transmission - DOS	LGS-3T DOS	4,457	0.399%	478,360					10.73%
75	Large General Service - X: Primary - DOS	LGS-XP DOS	5,599	0.501%	600,961					10.73%
76	Large General Service - X: Secondary - DOS	LGS-XS DOS	165	0.015%	17,760					10.73%
77	Large General Service - X: Transmission - DOS	LGS-XT DOS	1,426	0.128%	153,049					10.73%
78	LGS - Water Pumping - 2: Secondary - DOS	LGS-2S-WP DOS	49	0.004%	5,304					10.73%
79	LGS - Water Pumping - 2: Transmission - DOS	LGS-2T-WP DOS	30	0.003%	3,271					10.73%
80	LGS - Water Pumping - 3: Primary - DOS	LGS-3P-WP DOS	453	0.040%	48,586					10.73%
81	LGS - Water Pumping - 3: Secondary - DOS	LGS-3S-WP DOS	156	0.014%	16,767					10.73%
82	LGS - Water Pumping - 3: Transmission - DOS	LGS-3T-WP DOS	162	0.014%	17,390					10.73%
83	**Total DOS**		33,455	2.993%	3,591,046	369	31	31		
84	**Total - all classes with Distribution Only Service**		1,117,951	100.000%	$ 120,000,000	11,436,017	953,001	976,441		
85	**Bill Credit % of BTGR Revenue**				10.73%					

Data Sources/Notes

1. BTGR Revenue for Bundled Classes based on Recorded BTGR Revenue from Statement J, Schedule J-5 Proposed (For LGS-3 MPE, see Footnote 4).
For DOS classes, BTGR Revenue is estimated based on Present BTGR Revenue from Statement O, page 10 with scalers applied based on the ratio of Recorded kWh to Annualized kWh for each DOS schedule based on Statement J, Schedule J-9 Proposed.

2. From Schedule J-9 Proposed Recorded Bills.

3. Recorded bills divided by 12.

4. MPE allocation is set at 0.

EXHIBIT 2

Exhibit 2

System Size	Lower Bound	Upper Bound	Count of Applications	Percent of Total Applications	Fee
0-10kW	0	9.999	12808	84.5%	$ 130.00
10-25kW	10	24.999	2287	15.1%	$ 200.00
25-100kW	25	99.999	35	0.2%	$ 500.00
100-500kW	100	499.999	20	0.1%	$ 500.00
500-1,000kW	500	999.999	0	0.0%	$ 500.00
1,000-2,000kW	1000	1999.999	1	0.0%	$ 500.00

EXHIBIT 3

Nevada Power Company
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Comparison of Present, Cost-based and Proposed Rate Revenue ($000s)

Line No	Class	Note	Annualized Bills	Sales (MWh)	Present Rate Revenue: Revenue	Present Rate Revenue: Effective Rate ($/kWh)	Results if Class Revenue Requirements were Set @ Reconciled Cost [1]: Cost-Based Revenue	% Change from Present	Effective Rate ($/kWh)	Class Revenue Requirements Based on Proposed Capping Methodology [2]: Proposed Rate Revenue	Difference from Cost	Change from Present Rate Revenue	% Change from Present	Effective Rate ($/kWh)	Combined AB 405 Proposed Revenue Change: % Change from Present	Effective Rate ($/kWh)	Line No
8																	8
9	Classes in Revenue Reconciliation																9
10	RS		6,270,084	7,039,880	$ 531,618	$ 0.07552	$ 499,991	-5.95%	$ 0.07102	$ 500,417	$ 426	$ (31,201)	-5.87%	$ 0.07108	-5.82%	$ 0.06993	10
11	RM		3,332,328	2,188,600	155,163	0.07090	130,308	-16.02%	0.05954	139,160	8,852	(16,004)	-10.31%	0.06358	-10.31%	0.06358	11
12	LRS		2,544	35,987	2,291	0.06366	1,739	-24.08%	0.04833	2,057	318	(234)	-10.22%	0.05716	-10.23%	0.05729	12
13	GS		902,424	584,169	37,466	0.06414	26,848	-28.34%	0.04596	33,539	6,690	(3,928)	-10.48%	0.05741	-10.49%	0.05728	13
14	LGS-1		378,072	3,897,464	168,894	0.04333	145,165	-14.05%	0.03725	152,129	6,964	(16,765)	-9.93%	0.03903			14
15	LGS-2S		14,976	2,365,736	86,306	0.03648	75,126	-12.95%	0.03176	77,729	2,602	(8,578)	-9.94%	0.03286			15
16	LGS-2P		312	67,742	1,921	0.02835	1,951	1.57%	0.02879	1,804	(147)	(117)	-6.08%	0.02663			16
17	LGS-2T	3	-	-	-	—	-	na	—	-	-	-	na	—			17
18	LGS-3S		1,512	800,641	26,409	0.03298	23,243	-11.99%	0.02903	23,746	503	(2,663)	-10.08%	0.02966			18
19	LGS-3P	4	1,284	1,588,420	51,261	0.03227	47,599	-7.14%	0.02997	47,504	(94)	(3,757)	-7.33%	0.02991			19
20	LGS-3T	4	60	397,435	7,409	0.01864	7,984	7.76%	0.02009	6,987	(997)	(422)	-5.69%	0.01758			20
21	LGS-XS		-	-	-	—	-	na	—	-	-	-	na	—			21
22	LGS-XP		-	-	-	—	-	na	—	-	-	-	na	—			22
23	LGS-XT		-	-	-	—	-	na	—	-	-	-	na	—			23
24	LGS-2S-WP		264	6,831	153	0.02235	300	96.69%	0.04395	149	(151)	(4)	-2.32%	0.02183			24
25	LGS-2P-WP		120	12,229	292	0.02388	314	7.47%	0.02567	274	(40)	(18)	-6.21%	0.02240			25
26	LGS-2T-WP	5	-	-	-	—	(13)	na	—	-	13	-	na	—			26
27	LGS-3S-WP		24	5,752	18	0.00319	44	138.34%	0.00760	18	(26)	(0)	-2.62%	0.00310			27
28	LGS-3P-WP		60	17,505	246	0.01403	315	28.32%	0.01801	228	(87)	(18)	-7.22%	0.01302			28
29	LGS-3T-WP	5	-	-	-	—	-	na	—	-	-	-	na	—			29
30	SL		7,224	150,361	1,440	0.00957	2,862	98.79%	0.01903	1,352	(1,510)	(88)	-6.09%	0.00899			30
31	RS-Pal		-	648	45	0.06929	32	-29.07%	0.04915	40	9	(4)	-9.88%	0.06245			31
32	GS-Pal		-	2,337	149	0.06357	105	-29.61%	0.04474	134	29	(15)	-9.99%	0.05721			32
33	IAIWP	3	-	-	-	—	-	na	—	-	-	-	na	—			33
34	RS-NEM	6	581,328	446,857	24,289	0.09183	45,838	88.72%	0.10258	23,123	(22,715)	(1,166)	-4.80%	0.08742			34
35	RM-NEM	6	2,976	1,664	113	0.07478	161	43.13%	0.09687	101	(60)	(12)	-10.30%	0.06708			35
36	LRS-NEM	6	132	433	33	0.08595	29	-14.17%	0.06578	29	1	(4)	-11.21%	0.07632			36
37	GS-NEM	6	1,356	2,550	81	0.04047	195	140.22%	0.07644	71	(124)	(10)	-12.86%	0.03526			37
38																	38
44	Partial Requirements & Optional Schedule Groups not Included in Reconciliation																44
45	Optional TOU		65,484	407,118	11,952	0.02936	nc	nc	nc	11,400	nc	(553)	-4.62%	0.02800	—	—	45
46	Optional TOU EVRR		19,812	34,347	1,721	0.05011	nc	nc	nc	1,593	nc	(128)	-7.47%	0.04637			46
47	NEM Optional TOU		8,664	4,744	349	0.07354	nc	nc	nc	321	nc	(28)	-7.95%	0.06769	—	—	47
48	NEM EVRR		5,628	5,052	227	0.04495	nc	nc	nc	217	nc	(11)	-4.64%	0.04286			48
49	Standby		192	118,801	3,501	0.02947	nc	nc	nc	3,314	nc	(187)	-5.35%	0.02790	—	—	49
50	EVCCR		48	3,420	203	0.05936	nc	nc	nc	182	nc	(21)	-10.31%	0.05324			50
51	DOS		1,956	2,608,913	34,805	0.01334	nc	nc	nc	27,975	nc	(6,829)	-19.62%	0.01072	—	—	51
53																	53
54	Total (Bundled & DOS)		11,598,888	22,296,207	$ 1,137,429	$ 0.05101	$ 1,010,134	na[1]	nc	$ 1,044,760	—	$ (92,670)	-8.15%	$ 0.04686	-8.15%	$ 0.04686	54
55																	55

$ 1,045,573	Statement I Revenue Requirement	
$ (92,670)	Change in Revenue Requiremer	$ (9,370)
-8.15%	Percent Change	

nc = Classes with existing customers, but for which reconciled marginal costs cannot or have not been determined.

1. Percent Change in revenues at full reconciled cost does not include classes where reconciled marginal costs cannot or have not been determined. Therefore, the overall change will not match the value when all revenues are included in the calculations.
2. The revenues are based upon the proposed rates, and because final rates are rounded, revenues will not exactly match the 'final' class revenue requirements shown on page 7 of Statement O. Classes not in reconciliation, and whose rates are set off of the reconciled classes' rates, may realize overall rate impacts that are outside of the cap limits.
3. No Customers in class
4. Cost-based revenue requirement for LGS-3P includes OLGS-3P HLF customers billed under the OAS. Additionally, one partial requirements LSR-2 LGS-3P and LSR-2 LGS-3T customer are included as explained in rate design testimony. The results shown here include these customers.
5. All customers in class are DOS customers; no bundled customers.
6. Class level information presented here includes all customers under NMR-G and NMR-A rate schedules. NEM class effective rates for cost-based revenue are based on delivered loads. Present rate and proposed rate revenue are calculated using delivered kWh sales for NMR-A customers and net-billed kWh sales for NMR-G customers.

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Unbundled Revenue Requirement and Rate Design Adjustments ($000's)

Line No.		Note	Total	Energy	Generation	Transmission	Distribution	Line No.
					28.71	7.01	17.27	
8								8
9	Marginal Cost Revenue		$ 1,043,396	[redacted]	$ 565,309	$ 138,071	$ 340,016	9
10								10
11	Unbundled Revenue Requirement	1	$ 1,045,573	[redacted]	$ 566,488	$ 138,359	$ 340,726	11
12						Total G, T & D	$ 1,045,573	12
13	Total Revenue Requirement Adjustments for Rate Design							13
14	Revenue Credit to Dist. for Specific Class Assignment							14
15	Power Factor (PF)		(743)	[redacted]			(743)	15
16	Additional Facilities and Maintenance (AF&M)		(65)	[redacted]			(65)	16
17								17
18	Optional TOU Revenue		(7,255)	[redacted]	(3,931)	(960)	(2,364)	18
19	Optional TOU NEM revenues		(1,533)	[redacted]	(831)	(203)	(500)	19
20	Standby Customer Revenue (Inc. Part Req. Customers)	2	(2,937)	[redacted]	(1,591)	(389)	(957)	20
21	DOS BTGR Revenue (exc. IRR and Impact Fees)	3	(12,571)	[redacted]			(12,571)	21
22	DOS Interclass Rate-Rebalancing Revenue		(691)	[redacted]	(374)	(91)	(225)	22
23	OLGS-3P HLF & MPE Rate Design Revenue adjustment		552	[redacted]	299	73	180	23
24	MPE Revenue Adjustment		1,931	[redacted]	1,931			24
25	EVCCR Discount Revenue Adjustment		54	[redacted]	43	11		25
26	Total		$ (23,259)	[redacted]	$ (4,454)	$ (1,559)	$ (17,246)	26
27								27
28	Class Specific Revenue Requirement Adjustments							28
29	Other Revenue	4	(1,952)	[redacted]			(1,952)	29
30	Customer Specific Facilities		388	[redacted]			388	30
31	DOS Impact Fee revenue		(14,447)	[redacted]	(14,447)			31
32	BTER Energy Credits (WAPA, Hoover B, EDRR)		-	[redacted]				32
33	Total Class Specific Adjustments		$ (16,011)	[redacted]	$ (14,447)	$ -	$ (1,564)	33
34								34
35	Total Adjustments to Total Revenue Requirement		$ (39,270)	[redacted]	$ (18,901)	$ (1,559)	$ (18,810)	35
36								36
37	Target Revenue Requirement for Rate Design		$ 1,006,304	[redacted]	$ 560,104	$ 136,800	$ 320,385	37
38								38

41 1. Unbundled Revenue Requirement from Unbundling Study (Statement H in Direct Filing, Statement I in Certification Filing) 41

42 2. Includes LSR revenues and optional time-of-use revenues. 42

43 3. Includes all "non-tax" DOS revenues, but excludes subsidy-related revenues. 43

44 4. Other Revenue include misc. revenues, returned check, power pedestal, and misc. damage revenues. 44

45 5. Revenue are based on reconciled cost-based revenues used for rate design and include standard flat-rate NEM customers using NMR-A rate structure. 45

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Transmission Revenue by Class for Rate Design

Line No.	Class	Unreconciled Cost-Based Transmission Revenue	Percent of Total	Reconciled Transmission Revenue Requirement	Rate Design Revenue Adjustments: Optional TOU Revenue	Optional TOU NEM revenues	Standby Customer Revenue	DOS BTGR Revenue (exc. IRR and Impact Fees)	DOS Interclass Rate-Rebalancing Revenue	OLGS 3P HLF Rate Design Revenue adjustment	BTER Energy Credits (WAPA, Hoover B, EDRR)	MPE Revenue Adjustment	EVCCR Revenue Adjustment	Transmission Cost Based Class Revenue for Rate Design	Line No.
8															8
9	RS	$ 66,498	48.16%	$ 66,637	$ (462)	$ (98)	$ (187)	$ -	$ (44)	$ 35	[redacted]		$ 5	$ 65,886	9
10	RM	16,406	11.88%	16,440	(114)	(24)	(46)	-	(11)	9	[redacted]		1	16,255	10
11	LRS	258	0.19%	259	(2)	(0)	(1)	-	(0)	0	[redacted]		0	256	11
12	GS	3,166	2.29%	3,173	(22)	(5)	(9)	-	(2)	2	[redacted]		0	3,137	12
13	LGS-1	21,467	15.55%	21,512	(149)	(32)	(60)	-	(14)	11	[redacted]		2	21,269	13
14	LGS-2S	11,641	8.43%	11,665	(81)	(17)	(33)	-	(8)	6	[redacted]		1	11,534	14
15	LGS-2P	293	0.21%	294	(2)	(0)	(1)	-	(0)	0	[redacted]		0	290	15
16	LGS-2T	-	0.00%	-	-	-	-	-	-	-	[redacted]		-	-	16
17	LGS-3S	3,574	2.59%	3,581	(25)	(5)	(10)	-	(2)	2	[redacted]		0	3,541	17
18	LGS-3P	7,215	5.23%	7,230	(50)	(11)	(20)	-	(5)	4	[redacted]		1	7,149	18
19	LGS-3T	1,694	1.23%	1,697	(12)	(2)	(5)	-	(1)	1	[redacted]		0	1,678	19
20	LGS-XS	-	0.00%	-	-	-	-	-	-	-	[redacted]		-	-	20
21	LGS-XP	-	0.00%	-	-	-	-	-	-	-	[redacted]		-	-	21
22	LGS-XT	-	0.00%	-	-	-	-	-	-	-	[redacted]		-	-	22
23	LGS-2S-WP	37	0.03%	37	(0)	(0)	(0)	-	(0)	0	[redacted]		0	36	23
24	LGS-2P-WP	50	0.04%	50	(0)	(0)	(0)	-	(0)	0	[redacted]		0	49	24
25	LGS-2T-WP	-	0.00%	-	-	-	-	-	-	-	[redacted]		-	-	25
26	LGS-3S-WP	0	0.00%	0	(0)	(0)	(0)	-	(0)	0	[redacted]		0	0	26
27	LGS-3P-WP	47	0.03%	47	(0)	(0)	(0)	-	(0)	0	[redacted]		0	47	27
28	LGS-3T-WP	-	0.00%	-	-	-	-	-	-	-	[redacted]		-	-	28
29	SL	93	0.07%	93	(1)	(0)	(0)	-	(0)	0	[redacted]		0	92	29
30	RS-Pal	0	0.00%	0	(0)	(0)	(0)	-	(0)	0	[redacted]		0	0	30
31	GS-Pal	1	0.00%	1	(0)	(0)	(0)	-	(0)	0	[redacted]		0	1	31
32	IAWP	-	0.00%	-	-	-	-	-	-	-	[redacted]		-	-	32
33	RS-NEM	5,581	4.04%	5,592	(39)	(8)	(16)	-	(4)	3	[redacted]		0	5,529	33
34	RM-NEM	22	0.02%	22	(0)	(0)	(0)	-	(0)	0	[redacted]		0	22	34
35	LRS-NEM	3	0.00%	3	(0)	(0)	(0)	-	(0)	0	[redacted]		0	3	35
36	GS-NEM	27	0.02%	27	(0)	(0)	(0)	-	(0)	0	[redacted]		0	26	36
37											[redacted]				37
38	TOTAL	$ 138,071	100.00%	$ 138,359	$ (960)	$ (203)	$ (389)	$ -	$ (91)	$ 73	[redacted]		$ 11	$ 136,800	38
39				from Sch. I-2											39
40															40
41															41
42															42
43	Summation of NEM customers into Standard Schedule for Rate Design														43
44	RS	$ 72,079	52.20%	$ 72,229	$ (501)	$ (106)	$ (203)	$ -	$ (48)	$ 38	$ -	$ -	$ 6	$ 71,415	44
45	RM	16,428	11.90%	16,462	(114)	(24)	(46)	-	(11)	9	-	-	1	16,277	45
46	LRS	261	0.19%	262	(2)	(0)	(1)	-	(0)	0	-	-	0	259	46
47	GS	3,193	2.31%	3,199	(22)	(5)	(9)	-	(2)	2	-	-	0	3,163	47
48															48
49															49

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Distribution Revenue by Class for Rate Design

				Class Specific Adjustments			Rate Design Revenue Adjustments									
Line No.	Class	Unreconciled Cost-Based Distribution Revenue	Percent of Total	Other Revenue Adjustment	Adjustment for Class Cust Spec. Facilities	Reconciled Distribution Revenue Requirement	Optional TOU Revenue	Optional TOU NEM revenues	Standby Customer Revenue	DOS BTGR Revenue (exc. IRR and Impact Fees)	DOS Interclass Rate-Rebalancing Revenue	OLGS-3P HLF Rate Design Revenue adjustment	MPE Revenue Adjustment	EVCCR Discount Revenue Adjustment	Distribution Cost Based Class Revenue for Rate Design	Line No.
8																8
9	RS	$ 176,976	52.66%	$ (1,004)		$ 177,197	$ (1,245)	$ (263)	$ (504)	$ (6,620)	$ (119)	$ 95	[redacted]	$ -	$ 168,541	9
10	RM	46,698	13.90%	(698)		46,323	(329)	(69)	(133)	(1,747)	(31)	25	[redacted]		44,039	10
11	LRS	493	0.15%	(0)		496	(3)	(1)	(1)	(18)	(0)	0	[redacted]		472	11
12	GS	13,073	3.89%	(132)		13,031	(92)	(19)	(37)	(489)	(9)	7	[redacted]		12,392	12
13	LGS-1	40,770	12.13%	(21)		41,032	(287)	(61)	(116)	(1,525)	(27)	22	[redacted]		39,038	13
14	LGS-2S	17,909	5.33%	(1)		18,033	(126)	(27)	(51)	(670)	(12)	10	[redacted]		17,157	14
15	LGS-2P	536	0.16%	-		540	(4)	(1)	(2)	(20)	(0)	0	[redacted]		514	15
16	LGS-2T	-	0.00%	-		-	-	-	-	-	-	-	[redacted]		-	16
17	LGS-3S	5,565	1.66%	(0)		5,603	(39)	(8)	(16)	(208)	(4)	3	[redacted]		5,331	17
18	LGS-3P	15,776	4.69%	(0)	-	15,885	(111)	(23)	(45)	(590)	(11)	8	[redacted]		15,114	18
19	LGS-3T	7	0.00%	-	388	394.50	(0)	(0)	(0)	(0)	(0)	0	[redacted]		394	19
20	LGS-XS	-	0.00%	-		-	-	-	-	-	-	-	[redacted]		-	20
21	LGS-XP	-	0.00%	-		-	-	-	-	-	-	-	[redacted]		-	21
22	LGS-XT	-	0.00%	-		-	-	-	-	-	-	-	[redacted]		-	22
23	LGS-2S-WP	134	0.04%	-		135	(1)	(0)	(0)	(5)	(0)	0	[redacted]		128	23
24	LGS-2P-WP	100	0.03%	-		100	(1)	(0)	(0)	(4)	(0)	0	[redacted]		96	24
25	LGS-2T-WP	2	0.00%	-	-	2	(0)	(0)	(0)	(0)	(0)	0	[redacted]		2	25
26	LGS-3S-WP	101	0.03%	-		101	(1)	(0)	(0)	(4)	(0)	0	[redacted]		97	26
27	LGS-3P-WP	304	0.09%	-		306	(2)	(0)	(1)	(11)	(0)	0	[redacted]		291	27
28	LGS-3T-WP	9	0.00%	-	-	9	(0)	(0)	(0)	(0)	(0)	0	[redacted]		8	28
29	SL	937	0.28%	(5)		938	(7)	(1)	(3)	(35)	(1)	1	[redacted]		893	29
30	RS-Pal	25	0.01%	(0)		25	(0)	(0)	(0)	(1)	(0)	0	[redacted]		24	30
31	GS-Pal	80	0.02%	(0)		81	(1)	(0)	(0)	(3)	(0)	0	[redacted]		77	31
32	IAWP	-	0.00%			-	-	-	-	-	-	-	[redacted]		-	32
33	RS-NEM	16,429	4.89%	(69)		16,454	(116)	(24)	(47)	(615)	(11)	9	[redacted]		15,650	33
34	RM-NEM	53	0.02%	(1)		52	(0)	(0)	(0)	(2)	(0)	0	[redacted]		50	34
35	LRS-NEM	14	0.00%	(0)		14	(0)	(0)	(0)	(1)	(0)	0	[redacted]		13	35
36	GS-NEM	68	0.02%	(0)		68	(0)	(0)	(0)	(3)	(0)	0	[redacted]		65	36
37						not a sum							[redacted]			37
38	TOTAL	$ 338,059	100.00%	$ (1,952)	$ 388	$ 340,726	$ (2,384)	$ (500)	$ (957)	$ (12,571)	$ (225)	$ 180	[redacted]	$ -	$ 320,385	38
39						from Sch I-2									$ 421	39
40					exc. Specific Class adjustments $	338,386										40
41																41
42						$ -										42
43	Summation of NEM customers into Standard Schedule for Rate Design															43
44	RS	$ 193,404	57.55%	$ (1,093)	$ -	$ 193,651	$ (1,361)	$ (288)	$ (551)	$ (7,235)	$ (130)	$ 104	$ -	$ -	$ 184,191	44
45	RM	46,751	13.91%	(699)	-	46,376	(329)	(70)	(133)	(1,749)	(31)	25	-	-	44,089	45
46	LRS	506	0.15%	(0)	-	509	(4)	(1)	(1)	(19)	(0)	0	-	-	485	46
47	GS	13,141	3.91%	(132)	-	13,100	(92)	(20)	(37)	(492)	(9)	7	-	-	12,457	47
48																48
49																49

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Generation Revenue by Class for Rate Design

Line No.	Class	Unreconciled Cost-Based Generation Revenue	Percent of Total	DOS R-BTER and BTER Impact Fee Revenue	Reconciled Generation Revenue Requirement	Rate Design Revenue Adjustments: Optional TOU Revenue	Optional TOU NEM revenues	Standby Customer Revenue	DOS BTGR Revenue (exc. IRR and Impact Fees)	DOS Interclass Rate-Rebalancing Revenue	CLGS-3P HLF Rate Design Revenue adjustment	DOS BTGR Impact Fee Revenue	BTER Energy Credits (WAPA, Hoover B, EDRR)	MPE Revenue Adjustment	EVCCR Revenue Adjustment	Generation Cost Based Class Revenue for Rate Design	Line No.
8																	8
9	RS	$ 268,032	47.41%	$ -	$ 268,591	$ (1,864)	$ (394)	$ (755)		$ (177)	$ 142	$ -	[redacted]		$ 21	$ 265,564	9
10	RM	70,665	12.50%	-	70,812	(491)	(104)	(199)		(47)	37	-	[redacted]		5	70,014	10
11	LRS	1,021	0.18%	-	1,023	(7)	(2)	(3)		(1)	1	-	[redacted]		0	1,012	11
12	GS	11,425	2.02%	-	11,449	(79)	(17)	(32)		(8)	6	-	[redacted]		1	11,320	12
13	LGS-1	85,607	15.14%	-	85,785	(595)	(126)	(241)		(57)	45	-	[redacted]		7	84,819	13
14	LGS-2S	46,945	8.30%	-	47,043	(326)	(69)	(132)		(31)	25	-	[redacted]		4	46,513	14
15	LGS-2P	1,239	0.22%	-	1,242	(9)	(2)	(3)		(1)	1	-	[redacted]		0	1,228	15
16	LGS-2T	-	0.00%	-	-	-	-	-		-	-	-	[redacted]		-	-	16
17	LGS-3S	15,056	2.66%	-	15,087	(105)	(22)	(42)		(10)	8	-	[redacted]		1	14,917	17
18	LGS-3P	30,831	5.45%	-	30,895	(214)	(45)	(87)		(20)	16	-	[redacted]		2	30,547	18
19	LGS-3T	6,926	1.23%	-	6,941	(48)	(10)	(19)		(5)	4	-	[redacted]		1	6,862	19
20	LGS-XS	-	0.00%	-	-	-	-	-		-	-	-	[redacted]		-	-	20
21	LGS-XP	-	0.00%	-	-	-	-	-		-	-	-	[redacted]		-	-	21
22	LGS-XT	-	0.00%	-	-	-	-	-		-	-	-	[redacted]		-	-	22
23	LGS-2S-WP	162	0.03%	-	162	(1)	(0)	(0)		(0)	0	-	[redacted]		0	160	23
24	LGS-2P-WP	168	0.03%	-	168	(1)	(0)	(0)		(0)	0	-	[redacted]		0	166	24
25	LGS-2T-WP	-	0.00%	-	-	-	-	-		-	-	-	[redacted]		-	-	25
26	LGS-3S-WP	21	0.00%	-	21	(0)	(0)	(0)		(0)	0	-	[redacted]		0	20	26
27	LGS-3P-WP	188	0.03%	-	189	(1)	(0)	(1)		(0)	0	-	[redacted]		0	187	27
28	LGS-3T-WP	-	0.00%	-	-	-	-	-		-	-	-	[redacted]		-	-	28
29	SL	1,894	0.34%	-	1,898	(13)	(3)	(5)		(1)	1	-	[redacted]		0	1,877	29
30	RS-Pal	8	0.00%	-	8	(0)	(0)	(0)		(0)	0	-	[redacted]		0	8	30
31	GS-Pal	27	0.00%	-	27	(0)	(0)	(0)		(0)	0	-	[redacted]		0	27	31
32	IAIWP	-	0.00%	-	-	-	-	-		-	-	-	[redacted]		-	-	32
33	RS-NEM	24,888	4.40%	-	24,940	(173)	(37)	(70)		(16)	13	-	[redacted]		2	24,658	33
34	RM-NEM	90	0.02%	-	91	(1)	(0)	(0)		(0)	0	-	[redacted]		0	90	34
35	LRS-NEM	13	0.00%	-	13	(0)	(0)	(0)		(0)	0	-	[redacted]		0	13	35
36	GS-NEM	104	0.02%	-	105	(1)	(0)	(0)		(0)	0	-	[redacted]		0	103	36
37					not a sum								[redacted]				37
38	TOTAL	$ 565,309	100.00%	$ -	$ 566,488	$ (3,931)	$ (831)	$ (1,591)		$ (374)	$ 299	$ -	[redacted]		$ 43	$ 560,104	38
39					from Sch I-2												39
40				Generation Revenue for Rate Design $	565,309	$ (1,180)											40
41				w/ Specific Class adjustments	[redacted]	Separate											41
42																	42
43																	43
44																	44
45	Summation of NEM customers into Standard Schedule for Rate Design																45
46	RS	$ 292,919	51.82%	$ -	$ 293,530	$ (2,037)	$ (430)	$ (825)	$ -	$ (194)	$ 155	$ -	$ -	$ -	$ 22	$ 290,222	46
47	RM	70,755	12.52%	-	70,903	(492)	(104)	(199)	-	(47)	37	-	-	-	5	70,104	47
48	LRS	1,034	0.18%	-	1,036	(7)	(2)	(3)	-	(1)	1	-	-	-	0	1,024	48
49	GS	11,530	2.04%	-	11,554	(80)	(17)	(32)	-	(8)	6	-	-	-	1	11,424	49
50																	50
51																	51

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Energy Revenue by Class for Rate Design

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Line No.	Class	BTER Revenue	Unreconciled Cost-Based Energy Revenue	Percent of Total	Class Specific Adjustments: Hoover B, EDRR, MPE and WAPA Credits	Reconciled Energy Revenue Requirement	Rate Design Revenue Adjustments: Optional TOU Revenue	Optional TOU NEM revenues	Standby Customer Revenue	DOS Interclass Rate-Rebalancing Revenue	OLGS-3P HLF Rate Design Revenue adjustment	DOS R-BTER and BTER Impact Fee Revenue	MPE Revenue Adjustment	EVCCR Revenue Adjustment	Energy Cost Based Class Revenue for Rate Design	Excess/ Deficiency Present in BTER for Rate Design	Line No.
8																	8
9	RS	[redacted]					[redacted]								[redacted]	[redacted]	9
10	RM	[redacted]					[redacted]								[redacted]	[redacted]	10
11	LRS	[redacted]					[redacted]								[redacted]	[redacted]	11
12	GS	[redacted]					[redacted]								[redacted]	[redacted]	12
13	LGS-1	[redacted]					[redacted]								[redacted]	[redacted]	13
14	LGS-2S	[redacted]					[redacted]								[redacted]	[redacted]	14
15	LGS-2P	[redacted]					[redacted]								[redacted]	[redacted]	15
16	LGS-2T	[redacted]					[redacted]								[redacted]	[redacted]	16
17	LGS-3S	[redacted]					[redacted]								[redacted]	[redacted]	17
18	LGS-3P	[redacted]					[redacted]								[redacted]	[redacted]	18
19	LGS-3T	[redacted]					[redacted]								[redacted]	[redacted]	19
20	LGS-XS	[redacted]					[redacted]								[redacted]	[redacted]	20
21	LGS-XP	[redacted]					[redacted]								[redacted]	[redacted]	21
22	LGS-XT	[redacted]					[redacted]								[redacted]	[redacted]	22
23	LGS-2S-WP	[redacted]					[redacted]								[redacted]	[redacted]	23
24	LGS-2P-WP	[redacted]					[redacted]								[redacted]	[redacted]	24
25	LGS-2T-WP	[redacted]					[redacted]								[redacted]	[redacted]	25
26	LGS-3S-WP	[redacted]					[redacted]								[redacted]	[redacted]	26
27	LGS-3P-WP	[redacted]					[redacted]								[redacted]	[redacted]	27
28	LGS-3T-WP	[redacted]					[redacted]								[redacted]	[redacted]	28
29	SL	[redacted]					[redacted]								[redacted]	[redacted]	29
30	RS-Pal	[redacted]					[redacted]								[redacted]	[redacted]	30
31	GS-Pal	[redacted]					[redacted]								[redacted]	[redacted]	31
32	IAIWP	[redacted]					[redacted]								[redacted]	[redacted]	32
33	RS-NEM	[redacted]					[redacted]								[redacted]	[redacted]	33
34	RM-NEM	[redacted]					[redacted]								[redacted]	[redacted]	34
35	LRS-NEM	[redacted]					[redacted]								[redacted]	[redacted]	35
36	GS-NEM	[redacted]					[redacted]								[redacted]	[redacted]	36
37						not a sum											37
38	TOTAL	[redacted]					[redacted]								[redacted]	[redacted]	38
39						from Sch. I-2											39
40					Energy Revenue for Rate Design	-	$ (1,180)										40
41					w/ Specific Class adjustments $	-											41
42																	42
43																	43
44	Summation of NEM customers into Standard Schedule for Rate Design																44
45	RS	$ -	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	45
46	RM	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	46
47	LRS	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	47
48	GS	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	48
49																	49
50																	50

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Class Revenue Results Summary

Line No.	Class	Sales (MWh)	Cost Based Class Revenue by Function: Distribution	Transmission	Generation	Energy/ variable	Subtotal	Power Factor Revenue (exc. DOS)	Additional Facilities & Maintenance Revenue	Sum of Functional Cost Based Class Revenue for Rate Design	Interclass Rate Rebalancing Revenue	Capped Class Revenue Requirement	Revenue Proof	Percent of Total	Difference from Capped Revenue Requirement (Rounding)	Overall Effective Rate	Line No.
8																	8
9	RS	7,039,880	$ 168,541	$ 65,886	$ 265,564	[redacted]	$ 499,991	$ -	$ -	$ 499,991	$ (21,120)	$ 475,803	$ 500,417	49.5%	$ (375)	$ 0.06759	9
10	RM	2,188,600	44,039	16,255	70,014	[redacted]	130,308	-	-	130,308	8,842	139,637	139,160	13.8%	(56)	0.06380	10
11	LRS	35,987	472	256	1,012	[redacted]	1,739	-	-	1,739	316	2,034	2,057	0.2%	(1)	0.05652	11
12	GS	586,174	12,392	3,137	11,320	[redacted]	26,849	-	-	26,849	6,607	33,671	33,539	3.3%	5	0.05744	12
13	LGS-1	3,897,464	39,038	21,269	84,819	[redacted]	145,126	97	1	145,224	6,937	152,103	152,133	15.1%	31	0.03903	13
14	LGS-2S	2,365,736	17,157	11,534	46,513	[redacted]	75,203	346	-	75,550	2,602	77,726	77,729	7.7%	3	0.03285	14
15	LGS-2P	67,742	514	290	1,228	[redacted]	2,032	6	-	2,038	(147)	1,804	1,804	0.2%	(0)	0.02663	15
16	LGS-2T	-	-	-	-	[redacted]	-	-	-	-	na		-	0.0%	—	—	16
17	LGS-3S	822,586	5,331	3,541	14,917	[redacted]	23,789	90	-	23,878	541	23,783	23,746	2.3%	(38)	0.02891	17
18	LGS-3P	1,646,866	15,114	7,149	30,547	[redacted]	52,809	185	64	53,058	(123)	47,475	47,484	4.7%	8	0.02883	18
19	LGS-3T	397,435	394	1,678	6,862	[redacted]	8,935	9	-	8,943	(1,025)	6,959	6,958	0.7%	(0)	0.01751	19
20	LGS-XS	-	-	-	-	[redacted]	-	-	-	-	na		-	0.0%	—	—	20
21	LGS-XP	-	-	-	-	[redacted]	-	-	-	-	na		-	0.0%	—	—	21
22	LGS-XT	-	-	-	-	[redacted]	-	-	-	-	na		-	0.0%	—	—	22
23	LGS-2S-WP	6,831	128	36	160	[redacted]	325	2	-	327	(157)	143	149	0.0%	6	0.02099	23
24	LGS-2P-WP	12,229	96	49	166	[redacted]	311	3	-	314	(40)	274	274	0.0%	(0)	0.02243	24
25	LGS-2T-WP	-	2	-	-	[redacted]	2	-	-	2	na		-	0.0%	—	—	25
26	LGS-3S-WP	5,752	97	0	20	[redacted]	117	2	-	119	(26)	17	18	0.0%	1	0.00299	26
27	LGS-3P-WP	17,505	291	47	187	[redacted]	525	3	-	528	(84)	231	228	0.0%	(3)	0.01318	27
28	LGS-3T-WP	-	8	-	-	[redacted]	8	-	-	8	na		-	0.0%	—	—	28
29	SL	150,361	893	92	1,877	[redacted]	2,862	—	-	2,862	(1,510)	1,352	1,352	0.1%	(0)	0.00899	29
30	RS-Pal	648	24	0	8	[redacted]	32	-	-	32	9	40	40	0.0%	0	0.06240	30
31	GS-Pal	2,337	77	1	27	[redacted]	105	-	-	105	29	134	134	0.0%	(0)	0.05725	31
32	IAIWP	-	-	-	-	[redacted]	-	-	-	-	-	-	-	0.0%	-	—	32
33	RS-NEM	264,487	15,650	5,529	24,658	[redacted]	45,838	-	-	45,838	(793)	23,123	23,123	2.3%	—	0.08742	33
34	RM NEM	1,506	50	22	90	[redacted]	161			161	6	101	101	0.0%		0.06708	34
35	LRS-NEM	386	13	3	13	[redacted]	29	-	-	29	3	29	29	0.0%	—	0.07632	35
36	GS-NEM	2,005	65	26	103	[redacted]	195	-	-	195	23	71	71	0.0%	—	0.03526	36
37																	37
38	TOTAL	19,512,318	$ 320,385	$ 136,800	$ 560,104	[redacted]		$ 743	$ 65	$ 1,018,097	$ 890	$ 986,510	$ 1,010,544	100.0%	$ (420)	$ 0.05056	38
39																	39
40																	40
41																	41
42																	42
43	Summation of NEM customers into Standard Schedule for Rate Design																43
44	RS	7,304,367	$ 184,191	$ 71,415	$ 290,222	$ -	$ 545,828	$ -	$ -	$ 545,828	$ (21,913)	$ 498,926	$ 523,539	51.8%	$ (375)	$ 0.06831	44
45	RM	2,190,106	44,089	16,277	70,104	-	130,469	-	-	130,469	8,848	139,738	139,261	13.8%	(56)	0.06380	45
46	LRS	36,373	485	259	1,024	-	1,768	-	-	1,768	319	2,063	2,086	0.2%	(1)	0.05673	46
47	GS	588,180	12,457	3,163	11,424	-	27,044	-	-	27,044	6,630	33,741	33,609	3.3%	5	0.05737	47

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Class Revenue Adjustments Due to Cap & Floor Criteria (1)

Line No.	Class	Total Class Revenue Requirement: Sum of Functional Cost Based Class Revenue	Total Class Revenue Requirement: Percent of Total	Total Class Revenue Requirement: AB 405 Cost Based Class Revenue	Total Class Revenue Requirement: Percent of Total	Present Rate Revenue	% change over Present Rate Revenue	First Allocation - Cap: AB 405 Present Rate Revenue	AB405 Cost-Based Pct change over Present Rate Revenue	Result of Capping/Floor Proposal	Revenue Cap at Proposed	Re-set Revenue for classes subject to Cap Criteria (1)	Revenue to be re-allocated	Cost Based Class Revenue of Remaining Classes	Difference from Cost Based/Floor revenue of Uncapped Classes	Percent of Total	Class share of re-allocated Revenue	Class Revenue Requirement, after 1st Allocation	% change over Present Rate Revenue	Line No.
9	RS	$ 499,991	49.50%	$ 499,991	49.50%	$ 531,618	-5.95%	$ 531,618	-5.95%	-	-5.95%	$ 499,991	$ -	$ 499,991	$ (31,627)	40.48%	$ (2,173)	497,818	-6.36%	9
10	RM	130,308	12.90%	130,308	12.90%	155,163	-16.02%	155,163	-16.02%	Floor	-9.00%	141,199	(10,891)	-	(13,865)	17.88%	(959)	140,239	-9.62%	10
11	LRS	1,739	0.17%	1,739	0.17%	2,291	-24.08%	2,291	-24.08%	Floor	-9.00%	2,085	(346)	-	(206)	0.26%	(14)	2,071	-9.62%	11
12	GS	26,848	2.66%	26,848	2.66%	37,466	-28.34%	37,466	-28.34%	Floor	-9.00%	34,094	(7,246)	-	(3,372)	4.31%	(232)	33,863	-9.62%	12
13	LGS-1	145,165	14.37%	145,165	14.37%	168,894	-14.05%	168,894	-14.05%	Floor	-9.00%	153,693	(8,528)	-	(15,200)	19.44%	(1,044)	152,649	-9.62%	13
14	LGS-2S	75,126	7.44%	75,126	7.44%	86,306	-12.95%	86,306	-12.95%	Floor	-9.00%	78,539	(3,412)	-	(7,768)	9.93%	(534)	78,006	-9.62%	14
15	LGS-2P	1,951	0.19%	1,951	0.19%	1,921	1.57%	1,921	1.57%	Capped	-6.08%	1,804	147	-	-	0.00%	-	1,804	-6.08%	15
16	LGS-2T	-	0.00%	-	0.00%	-								-		0.00%	-			16
17	LGS-3S	23,243	2.30%	23,243	2.30%	26,409	-11.99%	26,409	-11.99%	Floor	-9.00%	24,032	(789)	-	(2,377)	3.04%	(163)	23,869	-9.62%	17
18	LGS-3P	47,599	4.71%	47,599	4.71%	51,261	-7.14%	51,261	-7.14%	-	-7.14%	47,599	-	47,599	(3,883)	4.88%	(252)	47,347	-7.64%	18
19	LGS-3T	7,984	0.79%	7,984	0.79%	7,409	7.76%	7,409	7.76%	Capped	-6.08%	6,959	1,025	-	-	0.00%	-	6,959	-6.08%	19
20	LGS-XS	-	0.00%	-	0.00%	-		-						-	-	0.00%	-			20
21	LGS-XP	-	0.00%	-	0.00%	-		-						-	-	0.00%	-			21
22	LGS-XT	-	0.00%	-	0.00%	-		-						-	-	0.00%	-			22
23	LGS-2S-WP	300	0.03%	300	0.03%	153	96.69%	153	96.69%	Capped	-6.08%	143	157	-	-	0.00%	-	143	-6.08%	23
24	LGS-2P-WP	314	0.03%	314	0.03%	292	7.47%	292	7.47%	Capped	-6.08%	274	40	-	-	0.00%	-	274	-6.08%	24
25	LGS-2T-WP	-	0.00%	-	0.00%	-								-	-	0.00%	-			25
26	LGS-3S-WP	44	0.00%	44	0.00%	18	138.34%	18	138.34%	Capped	-6.08%	17	26	-	-	0.00%	-	17	-6.08%	26
27	LGS-3P-WP	315	0.03%	315	0.03%	246	28.32%	246	28.32%	Capped	-6.08%	231	84	-	-	0.00%	-	231	-6.08%	27
28	LGS-3T-WP	8	0.00%	8	0.00%	-								-	-	0.00%	-			28
29	SL	2,862	0.28%	2,862	0.28%	1,440	98.79%	1,440	98.79%	Capped	-6.08%	1,352	1,510	-	-	0.00%	-	1,352	-6.08%	29
30	RS-Pal	32	0.00%	32	0.00%	45	-29.07%	45	-29.07%	Floor	-9.00%	41	(9)	-	(4)	0.01%	(0)	41	-9.62%	30
31	GS-Pal	105	0.01%	105	0.01%	149	-29.61%	149	-29.61%	Floor	-9.00%	135	(31)	-	(13)	0.02%	(1)	134	-9.62%	31
32	IA/WP	-																		32
33	RS-NEM	45,838	4.54%	45,838		24,289	88.72%	24,289	88.72%	Capped	-4.83%	$ 23,117	$ 22,721	$ -	$ -	0.00%	$ -	23,117	-4.83%	33
34	RM-NEM	161	0.02%	161		113	43.13%	113	43.13%	Capped	-4.83%	$ 107	$ 54	$ -	$ -	0.00%	$ -	107	-4.83%	34
35	LRS-NEM	29	0.00%	29		33	-14.17%	33	-14.17%	Floor	-9.00%	$ 30	$ (2)	$ -	$ (3)	0.00%	$ (0)	30	-9.62%	35
36	GS-NEM	195	0.02%	195		81	140.22%	81	140.22%	Capped	-4.83%	$ 77	$ 118	$ -	$ -	0.00%	$ -	77	-4.83%	36
37		Not a sum:				Not a Sum:	Overall Increase:													37
38	Total	$ 1,045,573	100.00%	$ 1,045,573	100.00%	$ 1,137,429	-8.06%					$ 1,016,519	$ (5,372)	$ 547,590	$ (78,198)	100%	$ (5,372)			38
39		$ 1,010,155	=sum=	$ 1,010,155		$ 1,095,596	$ (91,856)													39
40		$ 35,418	<Rev Credits: Revenue Credits, etc. PF and AFEM revenues																	40
41																				41

Line No.	Class	Second Allocation: Class Revenue Requirement, after 1st Allocation	Pct Change over Present Rate Revenue	Result of Capping/Floor Proposal	Revenue Cap at Proposed	Re-set Revenue for classes subject to Cap Criteria	Revenue to be re-allocated	Cost Based Class Revenue of Remaining Classes	Difference from Cost Based/Floor revenue of Uncapped Classes	Percent of Total	Class share of re-allocated Revenue	Class Revenue Requirement	% change over Present Rate Revenue	Final Class Revenue Allocation: Capped Class Revenue Requirement	Final Class Revenue Allocation: % change over Present Rate Revenue	Difference from Cost	Line No.
49	RS	$ 497,818	-6.36%	-	-6.36%	$ 497,818	$ -	$ 497,818	$ (33,800)	41.92%	$ 1,107	$ 498,926	-6.15%	$ 498,926	-6.15%	$ (1,065)	49
50	RM	140,239	-9.62%	Floor	-9.00%	$ 141,189	$ (959)	$ -	$ (13,865)	17.32%	458	$ 139,738	-9.94%	139,738	-9.94%	9,430	50
51	LRS	2,071	-9.62%	Floor	-9.00%	$ 2,085	$ (14)	$ -	$ (206)	0.26%	7	$ 2,063	-9.94%	2,063	-9.94%	324	51
52	GS	33,863	-9.62%	Floor	-9.00%	$ 34,094	$ (232)	$ -	$ (3,372)	4.18%	110	$ 33,741	-9.94%	33,741	-9.94%	6,893	52
53	LGS-1	152,649	-9.62%	Floor	-9.00%	$ 153,693	$ (1,044)	$ -	$ (15,200)	18.85%	498	$ 152,103	-9.94%	152,103	-9.94%	6,938	53
54	LGS-2S	78,006	-9.62%	Floor	-9.00%	$ 78,539	$ (534)	$ -	$ (7,768)	9.63%	254	$ 77,728	-9.94%	77,728	-9.94%	2,600	54
55	LGS-2P	1,804	-6.08%	Capped	-6.08%	$ 1,804	$ -	$ 1,804	$ -	0.00%	-	$ 1,804	-6.08%	1,804	-6.08%	(147)	55
56	LGS-2T							$ -	$ -	0.00%	-						56
57	LGS-3S	23,869	-9.62%	Floor	-9.00%	$ 24,032	$ (163)	$ -	$ (2,377)	2.95%	78	$ 23,783	-9.94%	23,783	-9.94%	541	57
58	LGS-3P	47,347	-7.64%	-	-7.64%	$ 47,347	$ -	$ 47,347	$ (3,914)	4.85%	128	$ 47,475	-7.39%	47,475	-7.39%	(123)	58
59	LGS-3T	6,959	-6.08%	Capped	-6.08%	$ 6,959	$ -	$ 6,959	$ -	0.00%	-	$ 6,959	-6.08%	6,959	-6.08%	(1,025)	59
60	LGS-XS							$ -	$ -	0.00%	-						60
61	LGS-XP							$ -	$ -	0.00%	-						61
62	LGS-XT							$ -	$ -	0.00%	-						62
63	LGS-2S-WP	143	-6.08%	Capped	-6.08%	$ 143	$ -	$ 143	$ -	0.00%	-	$ 143	-6.08%	143	-6.08%	(157)	63
64	LGS-2P-WP	274	-6.08%	Capped	-6.08%	$ 274	$ -	$ 274	$ -	0.00%	-	$ 274	-6.08%	274	-6.08%	(40)	64
65	LGS-2T-WP							$ -	$ -	0.00%	-						65
66	LGS-3S-WP	17	-6.08%	Capped	-6.08%	$ 17	$ -	$ 17	$ -	0.00%	-	$ 17	-6.08%	17	-6.08%	(26)	66
67	LGS-3P-WP	231	-6.08%	Capped	-6.08%	$ 231	$ -	$ 231	$ -	0.00%	-	$ 231	-6.08%	231	-6.08%	(84)	67
68	LGS-3T-WP							$ -	$ -	0.00%	-						68
69	SL	1,352	-6.08%	Capped	-6.08%	$ 1,352	$ -	$ 1,352	$ -	0.00%	-	$ 1,352	-6.08%	1,352	-6.08%	(1,510)	69
70	RS-Pal	41	-9.62%	Floor	-9.00%	$ 41	$ (0)	$ -	$ (4)	0.01%	0	$ 40	-9.94%	40	-9.94%	9	70
71	GS-Pal	134	-9.62%	Floor	-9.00%	$ 135	$ (1)	$ -	$ (13)	0.02%	0	$ 134	-9.94%	134	-9.94%	29	71
72	IA/WP																72
73	RS-NEM	23,117	-4.83%	Capped	-6.08%	$ 22,813	$ 304	$ -	$ -	0.00%	-	$ 23,420	-3.58%	23,420	-3.58%	(22,417)	73
74	RM-NEM	107	-4.63%	Capped	-6.08%	$ 106	$ 1	$ -	$ -	0.00%	-	$ 109	-3.58%	109	-3.58%	(53)	74
75	LRS-NEM	30	-9.62%	Floor	-9.00%	$ 30	$ (0)	$ -	$ (3)	0.00%	0	$ 30	-9.94%	30	-9.94%	1	75
76	GS-NEM	77	-4.83%	Capped	-6.08%	$ 76	$ 1	$ -	$ -	0.00%	-	$ 78	-3.58%	78	-3.58%	(117)	76
77																	77
78	Total						$ 2,642	$ 565,946	$ (80,622)	100.0%	$ 2,642	$ 1,010,147		$ 1,010,147			78
79														$ (8)			79

(1) Increases in rates cannot exceed the total average percentage increase in rates. For example: a 3% cap on an average increase of 10% will result in a rate increase of 13%. Classes not in reconciliation, and whose rates are set off of the reconciled classes' rates, may realize overall rate impacts that are outside of the cap limits. No class will receive a decrease in rates if a 0% floor is implemented.

(2) NEM classes include all customers under NMR-G and NMR-A rate schedules

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Non-Bypassable kWh Charges: Interclass Rate Rebalancing (IRR)

Line No.	Classes[1]	Bundled kWh Sales	DOS kWh Sales	Total kWh Sales	Sum of Functional Cost Based Class Revenue	Capped Class Revenue Requirement	Interclass Subsidy (difference)	Subsidy Component per kWh	Rounding	Note	Line No.
8	RS	7,039,880,433		7,304,367,364	$ 547,955	$ 526,039	$ (21,916)	$ (0.00300)	$ 3		8
9	RM	2,188,600,072		2,190,106,091	130,983	139,824	8,841	0.00404	7		9
10	LRS	35,987,038		36,373,364	1,773	2,093	319	0.00878	(0)		10
11	GS	584,168,954		586,174,249	27,186	33,814	6,628	0.01131	2		11
12	LGS-1	3,897,463,666		3,897,463,666	145,165	152,103	6,938	0.00178	(0)		12
13	LGS-2S	2,365,736,287		2,365,736,287	75,126	77,726	2,600	0.00110	3		13
14	LGS-2P	67,742,230		67,742,230	1,951	1,804	(147)	0.00001	147		14
15	LGS-2T	-		-	-		na	0.00178	—	<<Set equal to LGS-1>>	15
16	LGS-3S	822,585,854		822,585,854	23,243	23,783	541	0.00066	2		16
17	LGS-3P	1,646,665,536		1,646,665,536.39	47,599	47,475	(123)	(0.00007)	8		17
18	LGS-3T	397,434,700		397,434,700	7,984	6,959	(1,025)	0.00001	1,029		18
19	LGS-XS	-		-	-		na	0.00001	—	<<Set equal to LGS-XS DOS>>	19
20	LGS-XP	-		-	-		na	0.00131	—	<<Set equal to LGS-XP DOS>>	20
21	LGS-XT	-		-	-		na	0.00090	—	<<Set equal to LGS-XT DOS>>	21
22	LGS-2S-WP	6,831,160		6,831,160	300	143	(157)	0.00001	157		22
23	LGS-2P-WP	12,228,600		12,228,600	314	274	(40)	0.00001	40		23
24	LGS-2T-WP	-		-	-		na	0.00001	—	<<Set equal to LGS-2T WP DOS>>	24
25	LGS-3S-WP	5,751,817		5,751,817	44	17	(26)	0.00001	27		25
26	LGS-3P-WP	17,504,868		17,504,868	315	231	(84)	0.00001	85		26
27	LGS-3T-WP	-		-	8		na	0.00001	—	<<Set equal to LGS-3T WP DOS>>	27
28	SL	150,361,312		150,361,312	2,862	1,352	(1,510)	(0.01004)	(0)		28
29	RS-Pal	647,868		647,868	32	40	9	0.01325	(0)		29
30	GS-Pal	2,337,372		2,337,372	105	134	29	0.01250	(0)		30
31	IAIWP	-		na	-	-	-	na	—		31
32	RS-NEM	264,486,931		inc in Full Req Class							32
33	RM-NEM	1,506,019		inc in Full Req Class							33
34	LRS-NEM	386,326		inc in Full Req Class							34
35	GS-NEM	2,005,295		inc in Full Req Class							35
36											36
37	Bundled TOTAL	19,510,312,338		19,510,312,338	$ 1,012,944	$ 1,013,811	$ 876	<< Subsidy amount prior to RevReq adjustment when maintaining current rates.			37
38											38
39	**DISTRIBUTION ONLY SERVICE CLASSES – SET @ OTHERWISE APPLICABLE CLASS AS IDENTIFIED (If <0, then set to zero)[2]**										39
40	DOS: GS		52,832	na	na	na	na	$ 0.01131		<<Set equal to GS>>	40
41	DOS: LGS-1		6,590,602	na	na	na	na	0.00178		<<Set equal to LGS-1>>	41
42	DOS: LGS-2S		80,121,153	na	na	na	na	0.00110		<<Set equal to LGS-2S>>	42
43	DOS: LGS-2P		15,934,490	na	na	na	na	0.00001		<<Set equal to LGS-2P>>	43
44	DOS: LGS-2T		-	na	na	na	na	0.00178		<<Set equal to LGS-2T>>	44
45	DOS: LGS-3S		95,786,342	na	na	na	na	0.00066		<<Set equal to LGS-3S>>	45
46	DOS: LGS-3P		1,282,094,633	na	na	na	na	0.00001		<<Set equal to LGS-3P>>	46
47	DOS: LGS-3T		518,278,106	na	na	na	na	0.00001		<<Set equal to LGS-3T>>	47
48	DOS: LGS-XS		7,591,814	na	na	na	na	0.00001		<<Set to 0.00001 or Current x 94%>>	48
49	DOS: LGS-XP		279,670,254	na	na	na	na	0.00131		<<Set to 0.00001 or Current x 94%>>	49
50	DOS: LGS-XT		155,676,032	na	na	na	na	0.00090		<<Set to 0.00001 or Current x 94%>>	50
51	DOS: LGS-2S-WP		5,301,743	na	na	na	na	0.00001		<<Set equal to LGS-2S-WP>>	51
52	DOS: LGS-2P-WP		-	na	na	na	na	0.00001		<<Set equal to LGS-2P-WP>>	52
53	DOS: LGS-2T-WP		1,289,139	na	na	na	na	0.00001		<<Set to 0.00001 or Current x 94%>>	53
54	DOS: LGS-3S-WP		26,160,182	na	na	na	na	0.00001		<<Set equal to LGS-3S-WP>>	54
55	DOS: LGS-3P-WP		74,574,362	na	na	na	na	0.00001		<<Set equal to LGS-3P-WP>>	55
56	DOS: LGS-3T-WP		59,791,256	na	na	na	na	0.00001		<<Set to 0.00001 or Current x 94%>>	56

57

58 1. Optional TOU classes are not shown in this table, but have IRR rates equal to their otherwise applicable schedules. Any revenues collected from these classes are revenue credited (See page 2). 58

59 2. The DOS classes identified here are only those that presently have DOS customers in them. However, for other classes that are eligible for DOS, the IRR will be set similarly for all eligible classes. 59

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Comparison of Present and Proposed Rate Revenue

Line No	Class	Sales (kWh)	BTGR Revenue Present	BTGR Revenue Proposed	Percent Change	BTGR & BTER[1] Revenue Present	BTGR & BTER[1] Revenue Proposed	Percent Change	Total Revenue: BTGR & BTER Revenue Plus Other Rate Components[1] Present	Total Revenue: BTGR & BTER Revenue Plus Other Rate Components[1] Proposed	Percent Change	Line No
8	RS	7,039,880,433	$ 531,617,975	$ 500,418,882	-5.87%	$ 531,617,975	$ 500,418,882	-5.87%	$ 546,694,516	$ 515,693,423	-5.71%	8
9	RM	2,168,600,072	155,163,338	139,159,725	-10.31%	155,163,338	139,159,725	-10.31%	159,212,249	143,208,636	-10.05%	9
10	LRS	35,987,038	2,291,094	2,056,845	-10.22%	2,291,094	2,056,845	-10.22%	2,356,231	2,122,082	-9.94%	10
11	GS	594,168,964	37,466,138	33,538,537	-10.48%	37,466,138	33,536,537	-10.48%	38,231,399	34,303,798	-10.27%	11
12	LGS-1	3,897,463,666	168,893,509	152,128,952	-9.93%	168,893,509	152,128,952	-9.93%	174,038,089	157,273,532	-9.63%	12
13	LGS-2S	2,365,736,287	86,306,191	77,728,634	-9.94%	86,306,191	77,728,634	-9.94%	88,813,872	80,236,315	-9.66%	13
14	LGS-2P	67,742,230	1,920,539	1,803,827	-6.08%	1,920,539	1,803,827	-6.08%	1,984,895	1,868,183	-5.88%	14
15	LGS-2T	-	-	-	na	-	-	na	-	-	na	15
16	LGS-3S	800,640,755	25,748,757	23,157,270	-10.06%	25,748,757	23,157,270	-10.06%	26,813,609	24,222,122	-9.66%	16
17	LGS-3P	1,296,176,562	41,255,316	38,224,874	-7.35%	41,255,316	38,224,874	-7.35%	42,836,652	39,806,210	-7.07%	17
18	LGS-3T	291,815,628	5,203,130	4,781,628	-8.10%	5,203,130	4,781,629	-8.10%	5,611,812	5,190,311	-7.51%	18
19	LGS-XS	-	-	-	na	-	-	na	-	-	na	19
20	LGS-XP	-	-	-	na	-	-	na	-	-	na	20
21	LGS-XT	-	-	-	na	-	-	na	-	-	na	21
22	LGS-2S-WP	6,831,180	152,653	149,115	-2.32%	152,653	149,115	-2.32%	154,428	150,890	-2.29%	22
23	LGS-2P-WP	12,228,600	292,068	273,924	-6.21%	292,068	273,924	-6.21%	300,628	282,483	-6.04%	23
24	LGS-2T-WP	-	-	-	na	-	-	na	-	-	na	24
25	LGS-3S-WP	5,751,817	18,337	17,857	-2.62%	18,337	17,857	-2.62%	21,098	20,618	-2.28%	25
26	LGS-3P-WP	17,504,868	245,626	227,892	-7.22%	245,626	227,892	-7.22%	255,604	237,870	-6.94%	26
27	LGS-3T-WP	-	-	-	na	-	-	na	-	-	na	27
28	SL	150,361,312	1,439,520	1,351,860	-6.09%	1,439,520	1,351,860	-6.09%	1,519,212	1,431,552	-5.77%	28
29	RS-Pal	647,868	44,892	40,456	-9.88%	44,892	40,456	-9.88%	45,196	40,761	-9.81%	29
30	GS-Pal	2,337,372	148,576	133,728	-9.98%	148,576	133,728	-9.99%	149,674	134,826	-9.92%	30
31	IAIWP	-	-	-	na	-	-	na	-	-	na	31
32	**Optional Time of Use**											32
33	ORS-TOU	4,722,752	237,562	224,377	-5.55%	237,562	224,377	-5.55%	247,810	234,625	-5.32%	33
34	ORS-TOU OPT A	26,831,203	1,613,289	1,512,632	-6.24%	1,613,289	1,512,632	-6.24%	1,671,513	1,570,856	-6.02%	34
35	ORS-TOU OPT B	5,598,580	246,893	227,871	-7.70%	246,883	227,871	-7.70%	259,043	240,020	-7.34%	35
39	ORM-TOU	580,195	35,856	31,036	-13.44%	35,858	31,038	-13.44%	36,930	32,112	-13.05%	39
40	ORM-TOU OPT A	966,040	64,324	58,802	-8.56%	64,324	58,802	-8.58%	68,149	60,628	-8.35%	40
41	ORM-TOU OPT B	133,774	8,063	7,688	-4.65%	8,063	7,688	-4.65%	8,311	7,936	-4.51%	41
51	OGS-TOU	23,843,869	1,243,027	1,190,898	-4.19%	1,243,027	1,190,898	-4.18%	1,274,263	1,222,134	-4.09%	51
52	OLGS-1 TOU	81,567,130	2,970,359	2,758,950	-7.12%	2,970,359	2,758,950	-7.12%	3,078,027	2,866,617	-6.87%	52
53	OLGS-3P-HLF	262,854,722	5,533,026	5,387,352	-2.63%	5,533,026	5,387,352	-2.63%	5,853,710	5,708,036	-2.49%	53
54	**Optional Time of Use EVRR**											54
55	ORS-TOU EVRR	17,869,841	959,406	878,752	-8.41%	959,406	878,752	-8.41%	998,184	917,530	-8.08%	55
56	ORS-TOU Opt A EVRR	9,481,782	489,233	459,937	-5.99%	489,233	459,937	-5.99%	509,806	480,513	-5.75%	56
57	ORS-TOU Opt B EVRR	6,152,619	225,210	212,741	-5.54%	225,210	212,741	-5.54%	238,561	226,092	-5.23%	57
60	ORM-TOU EVRR	441,642	25,966	22,438	-13.59%	25,966	22,438	-13.59%	26,783	23,255	-13.17%	60
61	ORM-TOU OPT A EVRR	78,095	5,520	4,978	-9.80%	5,520	4,979	-9.80%	5,667	5,126	-9.55%	61
62	ORM-TOU OPT B EVRR	58,981	3,183	3,129	-1.71%	3,183	3,129	-1.71%	3,292	3,238	-1.65%	62
65	OLRS-TOU EVRR	260,038	11,978	10,087	-15.96%	11,978	10,067	-15.98%	12,448	10,536	-15.38%	65
70	OGS-TOU EVRR	3,241	689	653	-5.22%	689	653	-5.22%	694	658	-5.19%	70
71	OLGS-1-TOU EVRR	-	-	-	na	-	-	na	-	-	na	71
72	**Net Metering:**											72
73	RS-NEM	264,486,631	24,288,978	23,122,592	-4.80%	24,286,978	23,122,592	-4.80%	24,862,917	23,696,531	-4.69%	73
74	RM-NEM	1,606,019	112,621	101,017	-10.30%	112,621	101,017	-10.30%	115,407	103,803	-10.05%	74
75	LRS-NEM	386,326	33,206	29,483	-11.21%	33,206	29,483	-11.21%	33,904	30,181	-10.98%	75
76	GS-NEM	2,005,285	81,147	70,713	-12.86%	81,147	70,713	-12.86%	83,776	73,342	-12.45%	76
77	LGS-1 NEM	41,534	4,916	4,356	-11.42%	4,918	4,356	-11.42%	4,972	4,410	-11.29%	77
78	ORS-NEM	952,969	83,343	73,459	-11.86%	83,343	73,459	-11.86%	85,411	76,528	-11.57%	78
79	ORS-NEM OPT A	3,564,621	244,840	229,213	-6.38%	244,840	229,213	-6.38%	252,578	236,950	-6.19%	79
80	ORS-NEM OPT B	226,466	15,770	14,101	-10.58%	15,770	14,101	-10.58%	16,263	14,594	-10.26%	80
97	**NEM EVRR**											97
98	ORS-NEM EVRR	2,947,034	146,012	137,919	-5.54%	146,012	137,919	-5.54%	152,406	144,312	-5.31%	98
99	ORS-NEM OPT A EVRR	1,703,792	60,815	60,278	-0.88%	60,815	60,279	-0.88%	64,513	63,976	-0.83%	99
100	ORS-NEM OPT B EVRR	360,504	17,998	16,430	-8.66%	17,998	16,430	-8.66%	18,916	17,257	-8.28%	100
103	ORM-NEM EVRR	20,514	2,272	1,920	-15.50%	2,272	1,920	-15.50%	2,310	1,958	-15.24%	103
114	**Standby**											114
116	SSR - GS	-	-	-	na	-	-	na	-	-	na	116
117	SSR - LGS-1	1,115,600	53,011	52,984	-0.05%	53,011	52,984	-0.05%	54,484	54,457	-0.05%	117
118	LSR - LGS-2S	-	-	-	na	-	-	na	-	-	na	118
119	LSR - LGS-2P	-	-	-	na	-	-	na	-	-	na	119
120	LSR - LGS-2T	4,021,630	69,881	64,737	-7.36%	69,881	64,737	-7.36%	73,580	68,436	-6.99%	120
121	LSR - LGS-3S	-	-	-	na	-	-	na	-	-	na	121
122	LSR - LGS-3P	22,497,619	811,759	742,668	-8.51%	811,759	742,668	-8.51%	939,207	770,116	-8.23%	122
123	LSR - LGS-3T	61,166,025	2,566,769	2,453,596	-4.41%	2,566,769	2,453,596	-4.41%	2,694,402	2,581,228	-4.20%	123
133	**EVCCR**											133
134	LGS-2S EVCCR	3,419,651	203,005	182,083	-10.31%	203,005	182,093	-10.31%	206,631	185,709	-10.13%	134
135	LGS-2P EVCCR	-	-	-	na	-	-	na	-	-	na	135
136	LGS-2T EVCCR	-	-	-	na	-	-	na	-	-	na	136
137	LGS-3S EVCCR	-	-	-	na	-	-	na	-	-	na	137
138	LGS-3P EVCCR	-	-	-	na	-	-	na	-	-	na	138
139	LGS-3T EVCCR	-	-	-	na	-	-	na	-	-	na	139
144												144
145	**TOTAL Bundled**	19,686,073,843	$1,102,624,772	$ 1,016,784,263	-7.79%	$ 1,102,624,772	$ 1,016,784,263	-7.79%	$ 1,135,039,126	$ 1,049,198,618	-7.56%	145
146	Residential	9,614,487,549	$ 718,049,627	$ 669,114,872	-6.81%	$ 718,049,627	$ 669,114,872	-6.81%	$ 738,197,214	$ 689,262,459	-6.63%	146
147	Non-Residential	10,071,586,294	$ 384,575,145	$ 347,669,391	-9.60%	$ 384,575,145	$ 347,669,391	-9.60%	$ 396,841,913	$ 359,936,159	-9.30%	147
148												148
149	**DISTRIBUTION ONLY SERVICE (DOS)**											149
150	GS-DOS	52,832	$ 4,762	$ 4,658	-2.18%	$ 4,762	$ 4,658	-2.18%	$ 4,755	$ 4,651	-2.19%	150
151	LGS-1-DOS	6,590,602	159,369	136,894	-14.10%	159,369	136,894	-14.10%	158,372	135,897	-14.19%	151
152	LGS-2S-DOS	80,121,153	1,590,897	1,361,296	-14.44%	1,590,897	1,361,288	-14.44%	1,590,223	1,360,512	-14.45%	152
153	LGS-2P-DOS	15,934,490	250,848	207,107	-17.47%	250,848	207,107	-17.47%	252,281	208,450	-17.38%	153
154	LGS-2T-DOS	-	-	-	na	-	-	na	-	-	na	154
155	LGS-3S-DOS	85,786,342	2,316,632	1,961,177	-15.34%	2,316,632	1,961,177	-15.34%	2,320,911	1,965,456	-15.32%	155
156	LGS-3P-DOS	1,292,094,633	17,960,401	13,453,642	-25.09%	17,960,401	13,453,642	-25.09%	17,812,153	13,305,394	-25.30%	156
157	LGS-3T-DOS	518,278,106	4,464,755	3,681,801	-17.54%	4,464,755	3,681,801	-17.54%	4,388,752	3,605,798	-17.84%	157
158	LGS-XS-DOS	7,591,814	166,717	151,066	-9.37%	166,717	151,068	-9.37%	167,900	152,271	-9.31%	158
159	LGS-XP-DOS	278,670,254	5,622,732	5,206,498	-7.40%	5,622,732	5,206,499	-7.40%	5,564,811	5,148,578	-7.48%	159
160	LGS-XT-DOS	155,676,032	1,416,082	1,289,687	-8.93%	1,416,082	1,289,687	-8.93%	1,355,368	1,228,973	-9.33%	160
161	LGS-2S-WP-DOS	5,301,743	48,327	38,527	-20.28%	48,327	38,527	-20.28%	48,327	38,527	-20.28%	161
162	LGS-2P-WP-DOS	-	-	-	na	-	-	na	-	-	na	162
163	LGS-2T-WP-DOS	1,289,139	30,248	16,567	-45.23%	30,248	16,567	-45.23%	30,248	16,567	-45.23%	163
164	LGS-3S-WP-DOS	26,160,162	159,304	72,861	-54.26%	159,304	72,861	-54.26%	159,304	72,861	-54.26%	164
165	LGS-3P-WP-DOS	74,574,362	453,060	300,985	-33.57%	453,060	300,985	-33.57%	453,060	300,985	-33.57%	165
166	LGS-3T-WP-DOS	58,791,256	160,344	92,663	-42.21%	160,344	92,663	-42.21%	160,344	92,663	-42.21%	166
167												167
168	**DOS TOTAL**	2,609,912,840	$ 34,804,678	$ 27,975,442	-19.62%	$ 34,804,678	$ 27,975,442	-19.62%	$ 34,466,819	$ 27,637,583	-19.81%	168
169												169
170	**TOTAL (Inc. DOS)**	22,294,986,783	$1,137,429,450	$ 1,044,759,705	-8.15%	$ 1,137,429,450	$ 1,044,759,705	-8.15%	$ 1,169,505,945	$ 1,076,836,200	-7.92%	170
171												171

172 Note: Classes not in reconciliation, and whose rates are set off of the reconciled classes' rates, may realize overall rate impacts that are outside of the cap limits. 172

173 1. Present BTER and DEAA revenues are based on July 1, 2020 rates. 173

174 2. Partial requirements customers included in LGS-3P and LGS-3T for rate design purposes are presented in their respective standby schedules. 174

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Verification of Present Rate Components & Comparison to Proposed Revenue

Line No.	Class	Sales	BTER Revenue Present	BTER Revenue Proposed	BTER Percent Change	DEAA Revenue Present	DEAA Revenue Proposed	DEAA Percent Change	EE Revenue Present	EE Revenue Proposed	EE Percent Change	REPR Revenue Present	REPR Revenue Proposed	REPR Percent Change	Line No.
9		Residential Rate	[redacted]			[redacted]			Rates vary by Class			$ (0.00039)	$ (0.00039)		9
10		Non-Residential Rate	[redacted]			[redacted]						$ (0.00039)	$ (0.00039)		10
11															11
12	RS	7,039,880,433	[redacted]		na	[redacted]		na	$ 18,022,094	$ 18,022,094	0.0%	$ (2,745,553)	$ (2,745,553)	0.0%	12
13	RM	2,188,600,072	[redacted]		na	[redacted]		na	4,902,465	4,902,465	0.0%	(853,554)	(853,554)	0.0%	13
14	LRS	35,987,038	[redacted]		na	[redacted]		na	79,172	79,172	0.0%	(14,036)	(14,036)	0.0%	14
15	GS	584,168,954	[redacted]		na	[redacted]		na	993,087	993,087	0.0%	(227,826)	(227,826)	0.0%	15
16	LGS-1	3,897,463,666	[redacted]		na	[redacted]		na	6,664,591	6,664,591	0.0%	(1,520,011)	(1,520,011)	0.0%	16
17	LGS-2S	2,365,736,287	[redacted]		na	[redacted]		na	3,430,318	3,430,318	0.0%	(922,637)	(922,637)	0.0%	17
18	LGS-2P	67,742,230	[redacted]		na	[redacted]		na	90,775	90,775	0.0%	(26,419)	(26,419)	0.0%	18
19	LGS-2T	-	[redacted]		na	[redacted]		na	-	-	na	-	-	na	19
20	LGS-3S	800,640,755	[redacted]		na	[redacted]		na	1,377,102	1,377,102	0.0%	(312,250)	(312,250)	0.0%	20
21	LGS-3P	1,296,176,562	[redacted]		na	[redacted]		na	2,086,845	2,086,845	0.0%	(505,509)	(505,509)	0.0%	21
22	LGS-3T	291,915,629	[redacted]		na	[redacted]		na	522,529	522,529	0.0%	(113,847)	(113,847)	0.0%	22
23	LGS-XS	-	[redacted]		na	[redacted]		na	-	-	na	-	-	na	23
24	LGS-XP	-	[redacted]		na	[redacted]		na	-	-	na	-	-	na	24
25	LGS-XT	-	[redacted]		na	[redacted]		na	-	-	na	-	-	na	25
26	LGS-2S-WP	6,831,160	[redacted]		na	[redacted]		na	4,440	4,440	0.0%	(2,664)	(2,664)	0.0%	26
27	LGS-2P-WP	12,228,600	[redacted]		na	[redacted]		na	13,329	13,329	0.0%	(4,769)	(4,769)	0.0%	27
28	LGS-2T-WP	-	[redacted]		na	[redacted]		na	-	-	na	-	-	na	28
29	LGS-3S-WP	5,751,817	[redacted]		na	[redacted]		na	5,004	5,004	0.0%	(2,243)	(2,243)	0.0%	29
30	LGS-3P-WP	17,504,868	[redacted]		na	[redacted]		na	16,805	16,806	0.0%	(6,827)	(6,827)	0.0%	30
31	LGS-3T-WP	-	[redacted]		na	[redacted]		na	-	-	na	-	-	na	31
32	SL	150,361,312	[redacted]		na	[redacted]		na	138,333	138,333	0.0%	(58,641)	(58,641)	0.0%	32
33	RS-Pal	647,868	[redacted]		na	[redacted]		na	557	557	0.0%	(253)	(253)	0.0%	33
34	GS-Pal	2,337,372	[redacted]		na	[redacted]		na	2,010	2,010	0.0%	(912)	(912)	0.0%	34
35	IAIWP	-	[redacted]		na	[redacted]		na	-	-	na	-	-	na	35
36	**Optional Time of Use**														36
37	ORS-TOU	4,722,752	[redacted]		na	[redacted]		na	12,090	12,090	0.0%	(1,842)	(1,842)	0.0%	37
38	ORS-TOU OPT A	26,831,203	[redacted]		na	[redacted]		na	68,688	68,688	0.0%	(10,464)	(10,464)	0.0%	38
39	ORS-TOU OPT B	5,598,560	[redacted]		na	[redacted]		na	14,333	14,333	0.0%	(2,183)	(2,183)	0.0%	39
43	ORM-TOU	580,195	[redacted]		na	[redacted]		na	1,300	1,300	0.0%	(226)	(226)	0.0%	43
44	ORM-TOU OPT A	986,040	[redacted]		na	[redacted]		na	2,210	2,210	0.0%	(385)	(385)	0.0%	44
45	ORM-TOU OPT B	133,774	[redacted]		na	[redacted]		na	300	300	0.0%	(52)	(52)	0.0%	45
55	OGS-TOU	23,843,869	[redacted]		na	[redacted]		na	40,535	40,535	0.0%	(9,299)	(9,299)	0.0%	55
56	OLGS-1 TOU	81,567,130	[redacted]		na	[redacted]		na	139,479	139,479	0.0%	(31,811)	(31,811)	0.0%	56
57	OLGS-3P-HLF	262,854,722	[redacted]		na	[redacted]		na	423,197	423,197	0.0%	(102,513)	(102,513)	0.0%	57
58	**Optional Time of Use EVRR**														58
59	ORS-TOU EVRR	17,869,841	[redacted]		na	[redacted]		na	45,747	45,747	0.0%	(6,969)	(6,969)	0.0%	59
60	ORS-TOU Opt A EVRR	9,481,782	[redacted]		na	[redacted]		na	24,273	24,273	0.0%	(3,698)	(3,698)	0.0%	60
61	ORS-TOU Opt B EVRR	6,152,819	[redacted]		na	[redacted]		na	15,751	15,751	0.0%	(2,400)	(2,400)	0.0%	61
64	ORM-TOU EVRR	441,642	[redacted]		na	[redacted]		na	989	989	0.0%	(172)	(172)	0.0%	64
65	ORM-TOU OPT A EVRR	79,095	[redacted]		na	[redacted]		na	178	178	0.0%	(31)	(31)	0.0%	65
66	ORM-TOU OPT B EVRR	58,981	[redacted]		na	[redacted]		na	132	132	0.0%	(23)	(23)	0.0%	66
69	OLRS-TOU EVRR	260,038	[redacted]		na	[redacted]		na	571	571	0.0%	(101)	(101)	0.0%	69
74	OGS-TOU EVRR	3,241	[redacted]		na	[redacted]		na	6	6	0.0%	(1)	(1)	0.0%	74
75	OLGS-1-TOU EVRR	-	[redacted]		na	[redacted]		na	-	-	na	-	-	na	75
76	**Net Metering:**														76
77	RS-NEM	264,486,931	[redacted]		na	[redacted]		na	677,089	677,089	0.0%	(103,150)	(103,150)	0.0%	77
78	RM-NEM	1,506,019	[redacted]		na	[redacted]		na	3,373	3,373	0.0%	(587)	(587)	0.0%	78
79	LRS-NEM	386,326	[redacted]		na	[redacted]		na	849	849	0.0%	(151)	(151)	0.0%	79
80	GS-NEM	2,005,295	[redacted]		na	[redacted]		na	3,411	3,411	0.0%	(782)	(782)	0.0%	80
81	LGS-1 NEM	41,534	[redacted]		na	[redacted]		na	70	70	0.0%	(16)	(16)	0.0%	81
82	ORS-NEM	952,989	[redacted]		na	[redacted]		na	2,440	2,440	0.0%	(372)	(372)	0.0%	82
83	ORS-NEM OPT A	3,564,821	[redacted]		na	[redacted]		na	9,128	9,128	0.0%	(1,390)	(1,390)	0.0%	83
84	ORS-NEM OPT B	226,466	[redacted]		na	[redacted]		na	581	581	0.0%	(88)	(88)	0.0%	84
101	**NEM EVRR**														101
102	ORS-NEM EVRR	2,947,034	[redacted]		na	[redacted]		na	7,543	7,543	0.0%	(1,149)	(1,149)	0.0%	102
103	ORS-NEM OPT A EVRR	1,703,792	[redacted]		na	[redacted]		na	4,362	4,362	0.0%	(664)	(664)	0.0%	103
104	ORS-NEM OPT B EVRR	380,504	[redacted]		na	[redacted]		na	976	976	0.0%	(148)	(148)	0.0%	104
107	ORM-NEM EVRR	20,514	[redacted]		na	[redacted]		na	46	46	0.0%	(8)	(8)	0.0%	107
118	**Standby**														118
120	SSR - GS	-	[redacted]		na	[redacted]		na	-	-	na	-	-	na	120
121	SSR - LGS-1	1,115,600	[redacted]		na	[redacted]		na	1,908	1,908	0.0%	(435)	(435)	0.0%	121
122	LSR - LGS-2S	-	[redacted]		na	[redacted]		na	-	-	na	-	-	na	122
123	LSR - LGS-2P	-	[redacted]		na	[redacted]		na	-	-	na	-	-	na	123
124	LSR - LGS-2T	4,021,830	[redacted]		na	[redacted]		na	5,268	5,268	0.0%	(1,569)	(1,569)	0.0%	124
125	LSR - LGS-3S	-	[redacted]		na	[redacted]		na	-	-	na	-	-	na	125
126	LSR - LGS-3P	22,497,819	[redacted]		na	[redacted]		na	36,222	36,222	0.0%	(8,774)	(8,774)	0.0%	126
127	LSR - LGS-3T	91,166,025	[redacted]		na	[redacted]		na	163,188	163,188	0.0%	(35,555)	(35,555)	0.0%	127
137	**EVCCR**														137
138	LGS-2S EVCCR	3,419,851	[redacted]		na	[redacted]		na	4,960	4,960	0.0%	(1,334)	(1,334)	0.0%	138
148															148
149	**TOTAL Bundled**	19,686,073,843	$ -	$ -	na	-	-	na	40,060,649	40,060,649	0.0%	(7,646,295)	(7,646,295)	0.0%	149
150	Residential	9,614,487,549	-	-	na	-	-	na	23,897,237	23,897,237	0.0%	(3,749,650)	(3,749,650)	0.0%	150
151	Non-Residential	10,071,586,294	-	-	na	-	-	na	16,163,412	16,163,412	0.0%	(3,896,644)	(3,896,644)	0.0%	151
152															152
153	**DISTRIBUTION ONLY SERVICE (DOS)**		R-BTER & BTER Impact Fee DOS Revenue												153
154	GS-DOS	52,832	[redacted]		na	[redacted]		na	-	-	na	(7)	(7)	0.0%	154
155	LGS-1-DOS	6,590,602	[redacted]		na	[redacted]		na	614	614	0.0%	(1,611)	(1,611)	0.0%	155
156	LGS-2S-DOS	60,121,153	[redacted]		na	[redacted]		na	23,459	23,459	0.0%	(24,233)	(24,233)	0.0%	156
157	LGS-2P-DOS	15,934,490	[redacted]		na	[redacted]		na	4,338	4,338	0.0%	(2,995)	(2,995)	0.0%	157
158	LGS-2T-DOS	-	[redacted]		na	[redacted]		na	-	-	na	-	-	na	158
159	LGS-3S-DOS	95,786,342	[redacted]		na	[redacted]		na	32,064	32,064	0.0%	(27,785)	(27,785)	0.0%	159
160	LGS-3P-DOS	1,282,094,633	[redacted]		na	[redacted]		na	89,018	89,018	0.0%	(237,266)	(237,266)	0.0%	160
161	LGS-3T-DOS	518,278,106	[redacted]		na	[redacted]		na	61,946	61,946	0.0%	(137,949)	(137,949)	0.0%	161
162	LGS-XS-DOS	7,591,814	[redacted]		na	[redacted]		na	4,144	4,144	0.0%	(2,961)	(2,961)	0.0%	162
163	LGS-XP-DOS	279,670,254	[redacted]		na	[redacted]		na	51,150	51,150	0.0%	(109,071)	(109,071)	0.0%	163
164	LGS-XT-DOS	155,676,032	[redacted]		na	[redacted]		na	-	-	na	(60,714)	(60,714)	0.0%	164
165	LGS-2S-WP-DOS	5,301,743	[redacted]		na	[redacted]		na	-	-	na	-	-	na	165
166	LGS-2P-WP-DOS	-	[redacted]		na	[redacted]		na	-	-	na	-	-	na	166
167	LGS-2T-WP-DOS	1,289,139	[redacted]		na	[redacted]		na	-	-	na	-	-	na	167
168	LGS-3S-WP-DOS	26,160,182	[redacted]		na	[redacted]		na	-	-	na	-	-	na	168
169	LGS-3P-WP-DOS	74,574,362	[redacted]		na	[redacted]		na	-	-	na	-	-	na	169
170	LGS-3T-WP-DOS	59,791,256	[redacted]		na	[redacted]		na	-	-	na	-	-	na	170
171															171
172	DOS TOTAL	$ 2,608,912,940	$ -	$ -	na	$ -	$ -	na	$ 266,733	$ 266,733	0.0%	$ (604,592)	$ (604,592)	0.0%	172
173															173
174	TOTAL	64,276,047,409	$ -	$ -	na	$ -	$ -	na	$ 40,327,382	$ 40,327,382	0.0%	$ (8,250,887)	$ (8,250,887)	0.0%	174
175				$ -			$ -			$ -			$ -		175
176															176

Nevada Power Company
Statement O

Summary of Proposed Rates -- Bundled

Line No.	Class	Note	Distribution Charges: Charge, per Cust	Distribution Charges: Meter Charge	Distribution Charges: Facilities Charge, per kW (1)	T and G Demand Charges, metered kW: Summer On Peak	T and G Demand Charges, metered kW: Summer Mid Peak	T and G Demand Charges, metered kW: Winter -OR - All Periods	BTGR Energy, per kWh (includes IRR): Critical Peak	BTGR Energy: Summer On Peak	BTGR Energy: Summer Mid Peak	BTGR Energy: Summer Off Peak	BTGR Energy: Winter -OR - All Periods	BTGR Energy: Summer EVRR	BTGR Energy: Winter EVRR	BTER Energy, per kWh	Line No.
9	RS		$ 12.50										$ 0.05995			[redacted]	9
10	RM		7.70										0.05186			[redacted]	10
11	LRS		70.70										0.05216			[redacted]	11
12	GS		25.50	$ 2.50									0.01802			[redacted]	12
13	LGS-1		15.80	6.25	$ 3.69			$ 4.01					0.01522			[redacted]	13
14	LGS-2S		122.40	9.75	2.68	$ 12.81	$ 2.65	0.80		$ 0.03242	$ 0.01573	$ 0.00053	0.00572			[redacted]	14
15	LGS-2P		207.70	65.00	2.34	10.59	2.47	0.80		0.03817	0.01763	0.00107	0.00464			[redacted]	15
16	LGS-2T		182.00	23.00	0.61	11.46	2.67	0.75		0.04425	0.00766	0.00001	0.00066			[redacted]	16
17	LGS-3S		122.00	3.00	2.82	12.44	3.00	0.80		0.03591	0.01718	0.00130	0.00483			[redacted]	17
18	LGS-3P		214.10	76.25	2.73	13.61	3.36	0.85		0.03856	0.01300	0.00116	0.00279			[redacted]	18
19	LGS-3T		182.00	23.00	0.61	11.46	2.67	0.75		0.04425	0.00766	0.00001	0.00066			[redacted]	19
20	LGS-XS		4,743.00	20.52	0.91	12.44	3.00	0.80		0.03591	0.01718	0.00130	0.00483			[redacted]	20
21	LGS-XP		4,743.00	86.85	1.63	13.61	3.36	0.85		0.03856	0.01300	0.00116	0.00279			[redacted]	21
22	LGS-XT		4,743.00	139.05	-	11.46	2.67	0.75		0.04425	0.00766	0.00001	0.00066			[redacted]	22
23	LGS-2S-WP		128.70	9.75	0.80	15.46	15.46	0.80		0.00010	0.00010	0.00001	0.00002			[redacted]	23
24	LGS-2P-WP		208.80	65.00	1.17	13.06	13.06	0.60		0.05587	0.09974	0.00104	0.00105			[redacted]	24
25	LGS-2T-WP		169.10	-	0.61	14.13	14.13	0.75		0.05435	0.10098	0.00117	0.00117			[redacted]	25
26	LGS-3S-WP		149.90	3.00	0.45	15.44	15.44	0.80		0.00010	0.00010	0.00001	0.00002			[redacted]	26
27	LGS-3P-WP		234.20	76.25	0.92	16.97	16.97	0.85		0.03723	0.06984	0.00080	0.00081			[redacted]	27
28	LGS-3T-WP		189.10	23.00	0.61	17.42	17.42	0.85		0.03622	0.07071	0.00089	0.00090			[redacted]	28
29	IAWP															[redacted]	29
30																[redacted]	30
31	ORS-TOU		12.50							0.30471		0.01018	0.01831	0.00526	0.01078	[redacted]	31
32	ORS-TOU Opt A		12.50							0.26792		0.00671	0.00601	0.00214	0.00151	[redacted]	32
33	ORS-TOU Opt B		26.90							0.40478		0.00914	0.00469	0.00432	0.00032	[redacted]	33
34	ORS-TOU DDP		5.75		0.16	0.16		0.05					0.03642			[redacted]	34
35	ORS-TOU CPP		12.50						0.62872	0.27394		0.01391	0.00583	0.00862	0.00135	[redacted]	35
36	ORS-TOU CPP DDP		12.50			0.16		0.05	0.62872	0.16594		0.01251	0.01631	0.00736	0.01078	[redacted]	36
37	ORM-TOU		7.70							0.26153		0.03523	0.01164	0.02781	0.00657	[redacted]	37
38	ORM-TOU Opt A		7.70							0.24830		0.02469	0.00596	0.01832	0.00146	[redacted]	38
39	ORM-TOU Opt B		13.20							0.24920		0.05629	0.01616	0.04676	0.01064	[redacted]	39
40	ORM-TOU DDP		5.25		0.07	0.07		0.05					0.03873			[redacted]	40
41	ORM-TOU CPP		7.70						0.41715	0.23578		0.02964	0.01504	0.02277	0.00963	[redacted]	41
42	ORM-TOU CPP DDP		7.70			0.07		0.05	0.41715	0.21104		0.02964	0.00593	0.02277	0.00144	[redacted]	42
43	OLRS-TOU		70.70							0.30090		0.01793	0.01582	0.01224	0.01034	[redacted]	43
44	OLRS-TOU Opt A		70.70							0.27813		0.00868	0.00866	0.00391	0.00389	[redacted]	44
45	OLRS-TOU Opt B		181.10							0.23279		0.03210	0.00786	0.02499	0.00317	[redacted]	45
46	OLRS-TOU DDP		13.00		0.18	0.23		0.05					0.03668			[redacted]	46
47	OLRS-TOU CPP		70.70						0.33064	0.27169		0.01496	0.02229	0.00956	0.01616	[redacted]	47
48	OLRS-TOU CPP DDP		70.70			0.23		0.05	0.33064	0.22227		0.01496	0.01693	0.00956	0.01314	[redacted]	48
49	OGS-TOU		25.50	2.50						0.06215		0.01391	0.01260	0.00854	0.00736	[redacted]	49
50	OLGS-1-TOU		15.80	6.25	3.68	7.60	~ Summer Winter	0.26		0.10994		0.00680	0.00578	0.00214	0.00122	[redacted]	50
51	OLGS-3P-HLF		214.10	76.25	1.06	20.79	5.63	0.90		0.01088	0.00096	0.00043	0.00044			[redacted]	51
52																	52
58	Incremental EVCCR					EVCCR Demand Reduction Rates				EVCCR Transition kWh Adder Rates				EVCCR Credits			58
59	OLGS-1 EVCCR					(6.84)		(0.23)		0.05131			0.00079	(0.00419)	(0.00410)		59
60	LGS-2S EVCCR					(11.53)	(2.38)	(0.54)		0.08897	0.01964	-	0.00131	(0.00005)	(0.00057)		60
61	LGS-2P EVCCR					(9.53)	(2.22)	(0.54)		0.07034	0.01685	-	0.00115	(0.00011)	(0.00046)		61
62	LGS-2T EVCCR					(10.31)	(2.40)	(0.67)		0.03983	0.00689	-	0.00059	-	(0.00007)		62
63	LGS-3S EVCCR					(11.20)	(2.70)	(0.72)		0.08265	0.02057	-	0.00148	(0.00013)	(0.00048)		63
64	LGS-3P EVCCR					(12.25)	(3.02)	(0.76)		0.08923	0.02317	-	0.00157	(0.00012)	(0.00028)		64
65	LGS-3T EVCCR					(10.31)	(2.40)	(0.67)		0.06470	0.01554	-	0.00122	-	(0.00007)		65

Additional Charges:

Separate Billing

LGS-X & LGS-WP-X:	$	93.50	Per additional bill
DOS LGS-X & LGS-WP-X:	$	93.50	Per additional bill

Power Factor Charges ($/kVarh):

Summer:	$	0.00200	$/kVarh
Winter:	$	0.00100	$/kVarh

Customer Specific Facilities Charges	Charge per $ of: Utility	Charge per $ of: Customer Contributed
Transmission non-X customers	$ 0.00313	$ 0.00057
DOS Transmission non-X customers	$ 0.00313	$ 0.00057
OLGS-3P HLF customers	$ 0.00313	$ 0.00057

Notes:

(1) The facilities charge is per kWh for Residential and GS, per metered demand for LGS-1 and per the highest measured demand for the billing period and the prior twelve billing periods for all other. For non-transmission level customers, and non-X customers, the facilities charge recovers both the Rule 9 and primary distibution facilty costs. For LGSX customers the per kW facilty charge recovers only the primary distribution costs, with other facilities recovered in a customer specific facilty charge (CSFC).

(2) The non-LGS-X transmission-level customers have customer specific facilities (CSF) charges, with the rate applied on per dollar of investment. CSF charges may apply to either the investment made by NPC in the customers facilities or the customer's contributed investment (for O&M recovery). The per kW rate shown in this table is the average per kW facility rate for the class as a whole for NPC-related facilities. This average per kW rate may be applied only to new customers on a temporary basis should the details of the facilty calculations be incomplete at the start of service. The $/kW charge for transmission level classes is a placeholder until a CSFC is implemented. All new, permanent customers served under these tariffs will be placed on a CSF charge as soon as reasonably practical.

(3) The per kW facilty charge applies only to the LGSX-S and LGSX-P customers, who pay for their share of the primary distribution system through this charge. In addition to this charge, these customers continue to pay a CSFC based upon the cost of the customer facilities identified to serve them. See page 22 in Statement O for the CSFCs by LGS-X customer.

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Summary of Proposed Rates -- Bundled (continued)

Line No	Class	BTGR & BTER Energy, per kWh (the BTGR includes IRR Subsidy)							Additional Charges on per kWH Basis				Total Energy, per kWh (BTGR & BTER + EE + DEAA)							Line No
		Critical Peak	On Peak	Mid Peak	Off Peak	Winter -OR - All Periods	Summer EVRR	Winter EVRR	REPR	TRED	DEAA	EE	Critical Peak	On Peak	Mid Peak	Off Peak	Winter -OR - All Periods	Summer EVRR	Winter EVRR	
8																				8
9	RS					$ 0.05995			$ (0.00039)	$ 0.00070	[redacted]	$ 0.00256					$ 0.06282			9
10	RM					0.05186			(0.00039)	0.00070	[redacted]	0.00224					0.05441			10
11	LRS					0.05216			(0.00039)	0.00070	[redacted]	0.00220					0.05467			11
12	GS					0.01802			(0.00039)	0.00068	[redacted]	0.00170					0.02001			12
13	LGS-1					0.01522			(0.00039)	0.00068	[redacted]	0.00171					0.01722			13
14	LGS-2S		$ 0.03242	$ 0.01573	$ 0.00053	0.00572			(0.00039)	0.00068	[redacted]	0.00145		$ 0.03416	$ 0.01747	$ 0.00227	0.00746			14
15	LGS-2P		0.03817	0.01763	0.00107	0.00464			(0.00039)	0.00068	[redacted]	0.00134		0.03980	0.01926	0.00270	0.00627			15
16	LGS-2T		0.04425	0.00766	0.00001	0.00066			(0.00039)	0.00068	[redacted]	0.00131		0.04585	0.00926	0.00161	0.00226			16
17	LGS-3S		0.03591	0.01718	0.00130	0.00483			(0.00039)	0.00068	[redacted]	0.00172		0.03792	0.01919	0.00331	0.00684			17
18	LGS-3P		0.03856	0.01300	0.00116	0.00279			(0.00039)	0.00068	[redacted]	0.00161		0.04046	0.01490	0.00306	0.00469			18
19	LGS-3T		0.04425	0.00766	0.00001	0.00066			(0.00039)	0.00068	[redacted]	0.00179		0.04633	0.00974	0.00209	0.00274			19
20	LGS-XS		0.03591	0.01718	0.00130	0.00483			(0.00039)	0.00068	[redacted]	0.00192		0.03812	0.01939	0.00351	0.00704			20
21	LGS-XP		0.03856	0.01300	0.00116	0.00279			(0.00039)	0.00068	[redacted]	0.00178		0.04063	0.01507	0.00323	0.00486			21
22	LGS-XT		0.04425	0.00766	0.00001	0.00066			(0.00039)	0.00068	[redacted]	0.00205		0.04659	0.01000	0.00235	0.00300			22
23	LGS-2S-WP		0.00010	0.00010	0.00001	0.00002			(0.00039)	0.00068	[redacted]	0.00065		0.00104	0.00104	0.00095	0.00096			23
24	LGS-2P-WP		0.05587	0.09974	0.00104	0.00105			(0.00039)	0.00068	[redacted]	0.00109		0.05725	0.10112	0.00242	0.00243			24
25	LGS-2T-WP		0.05435	0.10098	0.00117	0.00117			(0.00039)	0.00068	[redacted]	0.00109		0.05573	0.10236	0.00255	0.00255			25
26	LGS-3S-WP		0.00010	0.00010	0.00001	0.00002			(0.00039)	0.00068	[redacted]	0.00087		0.00126	0.00126	0.00117	0.00118			26
27	LGS-3P-WP		0.03723	0.06984	0.00080	0.00081			(0.00039)	0.00068	[redacted]	0.00096		0.03848	0.07109	0.00205	0.00206			27
28	LGS-3T-WP		0.03622	0.07071	0.00089	0.00090			(0.00039)	0.00068	[redacted]	0.00096		0.03747	0.07196	0.00214	0.00215			28
29	IAIWP					-			-	-	[redacted]						-			29
30											[redacted]									30
31	ORS-TOU		0.30471		0.01018	0.01631	$ 0.00526	$ 0.01078	(0.00039)	0.00070	[redacted]	0.00256		0.30758		0.01305	0.01918	$ 0.00813	$ 0.01365	31
32	ORS-TOU Opt A		0.26792		0.00671	0.00601	0.00214	0.00151	(0.00039)	0.00070	[redacted]	0.00256		0.27079		0.00958	0.00888	0.00501	0.00438	32
33	ORS-TOU Opt B		0.40478		0.00914	0.00469	0.00432	0.00032	(0.00039)	0.00070	[redacted]	0.00256		0.40765		0.01201	0.00756	0.00719	0.00319	33
34	ORS-TOU DDP					0.03642			(0.00039)	0.00070	[redacted]	0.00256					0.03929			34
35	ORS-TOU CPP	0.63007	0.27394		0.01391	0.00583	0.00862	0.00135	(0.00039)	0.00070	[redacted]	0.00256	0.63294	0.27681		0.01678	0.00870	0.01149	0.00422	35
36	ORS-TOU CPP DDP	0.63950	0.16594		0.01251	0.01631	0.00736	0.01078	(0.00039)	0.00070	[redacted]	0.00256	0.64237	0.16881		0.01538	0.01918	0.01023	0.01365	36
37	ORM-TOU		0.26153		0.03523	0.01164	0.02781	0.00657	(0.00039)	0.00070	[redacted]	0.00224		0.26408		0.03778	0.01419	0.03036	0.00912	37
38	ORM-TOU Opt A		0.24830		0.02469	0.00596	0.01832	0.00146	(0.00039)	0.00070	[redacted]	0.00224		0.25085		0.02724	0.00851	0.02087	0.00401	38
39	ORM-TOU Opt B		0.24920		0.05629	0.01616	0.04676	0.01064	(0.00039)	0.00070	[redacted]	0.00224		0.25175		0.05884	0.01871	0.04931	0.01319	39
40	ORM-TOU DDP					0.03673			(0.00039)	0.00070	[redacted]	0.00224					0.03928			40
41	ORM-TOU CPP	0.42678	0.23578		0.02964	0.01504	0.02277	0.00963	(0.00039)	0.00070	[redacted]	0.00224	0.42933	0.23833		0.03219	0.01759	0.02532	0.01218	41
42	ORM-TOU CPP DDP	0.41859	0.21104		0.02964	0.00593	0.02277	0.00144	(0.00039)	0.00070	[redacted]	0.00224	0.42114	0.21359		0.03219	0.00848	0.02532	0.00399	42
43	OLRS-TOU		0.30090		0.01793	0.01582	0.01224	0.01034	(0.00039)	0.00070	[redacted]	0.00220		0.30341		0.02044	0.01833	0.01475	0.01285	43
44	OLRS-TOU Opt A		0.27813		0.00868	0.00866	0.00391	0.00389	(0.00039)	0.00070	[redacted]	0.00220		0.28064		0.01119	0.01117	0.00642	0.00640	44
45	OLRS-TOU Opt B		0.23279		0.03210	0.00786	0.02499	0.00317	(0.00039)	0.00070	[redacted]	0.00220		0.23530		0.03461	0.01037	0.02750	0.00568	45
46	OLRS-TOU DDP					0.03668			(0.00039)	0.00070	[redacted]	0.00220					0.03919			46
47	OLRS-TOU CPP	0.34680	0.27169		0.01496	0.02229	0.00956	0.01616	(0.00039)	0.00070	[redacted]	0.00220	0.34931	0.27420		0.01747	0.02480	0.01207	0.01867	47
48	OLRS-TOU CPP DDP	0.34378	0.22227		0.01496	0.01893	0.00956	0.01314	(0.00039)	0.00070	[redacted]	0.00220	0.34629	0.22478		0.01747	0.02144	0.01207	0.01565	48
49	OGS-TOU		0.06215		0.01391	0.01260	0.00854	0.00736	(0.00039)	0.00068	[redacted]	0.00170		0.06414		0.01590	0.01459	0.01053	0.00935	49
50	OLGS-1-TOU		0.10994		0.00680	0.00578	0.00214	0.00122	(0.00039)	0.00068	[redacted]	0.00171		0.11194		0.00880	0.00778	0.00414	0.00322	50
51	OLGS-3P-HLF		0.01088	0.00096	0.00043	0.00044			(0.00039)	0.00068	[redacted]	0.00161		0.01278		0.00233	0.00234	0.00190	0.00190	51
52																				52

53 (1) The bundled proposed rates for Streetlights and PAL are shown on pages 14-16 of Statement O 53

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Proposed Street Lighting (SL) Rate Summary

Line No.	Lamp Type	Size & Pole Type	Watts	Class	Note	Monthly kWh	BTGR	BTER	Proposed BTGR & BTER Rate	DEAA Rate	TRED Rate	EE Rate	REPR Rate	UEC Rate	Total All Components Rate	Line No.
9																9
10										[redacted]	$ 0.00068	$ 0.00039	$ (0.00039)	$ 0.00039		10
11																11
12	Street Lights - Non-metered															12
13	Mercury Vapor	Non-Metered	100W	CLS 20		73	$ 1.16	[redacted]	**$ 1.16**	$ -	$ 0.05	$ 0.03	$ (0.03)	—	$ 1.21	13
14	Mercury Vapor	Non-Metered	100W	CLS 20		73	1.16	[redacted]	**1.16**	-	0.05	0.03	(0.03)	—	1.21	14
15	Mercury Vapor	Non-Metered	200W	CLS 21		103	1.38	[redacted]	**1.38**	-	0.07	0.04	(0.04)	—	1.45	15
16	Mercury Vapor	Non-Metered	200W	CLS 21		103	1.38	[redacted]	**1.38**	-	0.07	0.04	(0.04)	—	1.45	16
17	Mercury Vapor	Non-Metered	200W	CLS 22		165	1.80	[redacted]	**1.80**	-	0.11	0.06	(0.06)	—	1.91	17
18	Mercury Vapor	Non-Metered	200W	CLS 22		165	1.80	[redacted]	**1.80**	-	0.11	0.06	(0.06)	—	1.91	18
19	High Pressure	Non-Metered	200W	CLS 24		83	0.81	[redacted]	**0.81**	-	0.06	0.03	(0.03)	—	0.87	19
20	High Pressure	Non-Metered	200W	CLS 24		83	1.23	[redacted]	**1.23**	-	0.06	0.03	(0.03)	—	1.29	20
21	Municipal Street Lights - Public							[redacted]								21
22	Incandescent	n/a	100W	CLS 30		73	8.95	[redacted]	**8.95**	-	0.05	0.03	(0.03)	—	9.00	22
23	Incandescent	n/a	200W	CLS 31		120	8.55	[redacted]	**8.55**	-	0.08	0.05	(0.05)	—	8.63	23
24	Incandescent	n/a	200W	CLS 32		167	8.06	[redacted]	**8.06**	-	0.11	0.07	(0.07)	—	8.17	24
25	Mercury Vapor	Wood Pole	200W	CLS 33		73	8.90	[redacted]	**8.90**	-	0.05	0.03	(0.03)	—	8.95	25
26	Mercury Vapor	Wood Pole	200W	CLS 34		103	8.73	[redacted]	**8.73**	-	0.07	0.04	(0.04)	—	8.80	26
27	Mercury Vapor	Wood Pole	200W	CLS 35		165	8.09	[redacted]	**8.09**	-	0.11	0.06	(0.06)	—	8.20	27
28	Mercury Vapor	Steel Pole	200W	CLS 43		73	8.90	[redacted]	**8.90**	-	0.05	0.03	(0.03)	—	8.95	28
29	Mercury Vapor	Steel Pole	200W	CLS 44		103	8.73	[redacted]	**8.73**	-	0.07	0.04	(0.04)	—	8.80	29
30	Mercury Vapor	Steel Pole	200W	CLS 45		165	8.09	[redacted]	**8.09**	-	0.11	0.06	(0.06)	—	8.20	30
31	Sodium Vapor	n/a	100W	CLS 89		42	9.22	[redacted]	**9.22**	-	0.03	0.02	(0.02)	—	9.25	31
32	Sodium Vapor	n/a	200W	CLS 90		83	8.92	[redacted]	**8.92**	-	0.06	0.03	(0.03)	—	8.98	32
33	Municipal Street Lights - Customer Owned							[redacted]								33
34	Incandescent	n/a	200W	CLS 51		120	1.10	[redacted]	**1.10**	-	0.08	0.05	(0.05)	0.05	1.23	34
35	Mercury Vapor	n/a	200W	CLS 53		73	1.54	[redacted]	**1.54**	-	0.05	0.03	(0.03)	0.03	1.62	35
36	Mercury Vapor	n/a	200W	CLS 54		103	1.24	[redacted]	**1.24**	-	0.07	0.04	(0.04)	0.04	1.35	36
37	Mercury Vapor	n/a	200W	CLS 55		165	0.60	[redacted]	**0.60**	-	0.11	0.06	(0.06)	0.06	0.77	37
38	Street Lights - LED							[redacted]								38
39	LED	Non-Metered	100W	CLS 20		70	0.10	[redacted]	**0.10**	-	0.05	0.03	(0.03)	—	0.15	39
40	LED	Non-Metered	200W	CLS 21		35	0.10	[redacted]	**0.10**	-	0.02	0.01	(0.01)	—	0.12	40
41	LED	Non-Metered	200W	CLS 22		70	0.12	[redacted]	**0.12**	-	0.05	0.03	(0.03)	—	0.17	41
42	LED	Non-Metered	200W	CLS 24		70	0.12	[redacted]	**0.12**	-	0.05	0.03	(0.03)	—	0.17	42
43	Municipal Street Lights - LED							[redacted]								43
44	LED	n/a	100W	CLS 30		35	8.91	[redacted]	**8.91**	-	0.02	0.01	(0.01)	—	8.93	44
45	LED	n/a	200W	CLS 31		70	8.48	[redacted]	**8.48**	-	0.05	0.03	(0.03)	—	8.53	45
46	LED	n/a	200W	CLS 32		70	7.96	[redacted]	**7.96**	-	0.05	0.03	(0.03)	—	8.01	46
47	LED	Wood Pole	200W	CLS 33		70	8.86	[redacted]	**8.86**	-	0.05	0.03	(0.03)	—	8.91	47
48	LED	Wood Pole	200W	CLS 34		70	8.67	[redacted]	**8.67**	-	0.05	0.03	(0.03)	—	8.72	48
49																49
50	Metered	Metered	Metered	Metered		Mtrd	0.00879	-	**0.00879**	-	0.00068	0.00039	(0.00039)	0.00039	0.00986	50
51																51
52	Note: Municipal and Public Street Lights do not pay UEC charges.															52

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Proposed Residential Private Area Lighting (RS-PAL) Rate Summary

Line No.	Lamp Type	Size & Pole Type	Watts	Class	Note	Monthly kWh	BTGR	BTER	Proposed BTGR & BTER Rate	DEAA Rate	TRED Rate	EE Rate	REPR Rate	UEC Rate	Total All Components Rate	Line No.
9																9
10										[redacted]	$ 0.00070	$ 0.00087	$ (0.00039)	$ 0.00039		10
11																11
12	RS-PAL															12
13	Mercury Vapor	RATE A (Existing pole)	200W	CLS 10		73	$ 4.86	[redacted]	**$ 4.86**	$ -	$ 0.05	$ 0.06	$ (0.03)	0.03	$ 4.97	13
14	Mercury Vapor	RATE A (Existing pole)	200W	CLS 10		73	4.86	[redacted]	**4.86**	-	0.05	0.06	(0.03)	0.03	4.97	14
15	Mercury Vapor	RATE A (Existing pole)	200W	CLS 12		165	4.61	[redacted]	**4.61**	-	0.12	0.14	(0.06)	0.06	4.87	15
16	High Pressure	RATE A (Existing pole)	100W	CLS 14		42	4.98	[redacted]	**4.98**	-	0.03	0.04	(0.02)	0.02	5.05	16
17	High Pressure	RATE A (Existing pole)	100W	CLS 14		42	4.98	[redacted]	**4.98**	-	0.03	0.04	(0.02)	0.02	5.05	17
18	High Pressure	RATE A (Existing pole)	200W	CLS 15		83	4.94	[redacted]	**4.94**	-	0.06	0.07	(0.03)	0.03	5.07	18
19	High Pressure	RATE A (Existing pole)	200W	CLS 15		83	4.94	[redacted]	**4.94**	-	0.06	0.07	(0.03)	0.03	5.07	19
20	High Pressure	RATE A (Existing pole)	200W	CLS 12		165	4.31	[redacted]	**4.31**	-	0.12	0.14	(0.06)	0.06	4.57	20
21	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 11		73	12.00	[redacted]	**12.00**	-	0.05	0.06	(0.03)	0.03	12.11	21
22	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 11		73	12.00	[redacted]	**12.00**	-	0.05	0.06	(0.03)	0.03	12.11	22
23	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 13		165	11.75	[redacted]	**11.75**	-	0.12	0.14	(0.06)	0.06	12.01	23
24	High Pressure	RATE B (30 Foot pole)	100W	CLS 16		42	12.12	[redacted]	**12.12**	-	0.03	0.04	(0.02)	0.02	12.19	24
25	High Pressure	RATE B (30 Foot pole)	200W	CLS 15		83	12.08	[redacted]	**12.08**	-	0.06	0.07	(0.03)	0.03	12.21	25
26	LED	RATE A (Existing pole)	200W	CLS 10		70	4.77	[redacted]	**4.77**	-	0.05	0.06	(0.03)	0.03	4.88	26
27	LED	RATE A (Existing pole)	200W	CLS 12		70	2.97	[redacted]	**2.97**	-	0.05	0.06	(0.03)	0.03	3.08	27
28	LED	RATE A (Existing pole)	100W	CLS 14		35	4.70	[redacted]	**4.70**	-	0.02	0.03	(0.01)	0.01	4.75	28
29	LED	RATE A (Existing pole)	200W	CLS 15		70	4.60	[redacted]	**4.60**	-	0.05	0.06	(0.03)	0.03	4.71	29
30	LED	RATE B (30 Foot pole)	200W	CLS 11		70	11.92	[redacted]	**11.92**	-	0.05	0.06	(0.03)	0.03	12.03	30
31	LED	RATE B (30 Foot pole)	200W	CLS 13		70	9.70	[redacted]	**9.70**	-	0.05	0.06	(0.03)	0.03	9.81	31
32	LED	RATE B (30 Foot pole)	100W	CLS 16		35	11.91	[redacted]	**11.91**	-	0.02	0.03	(0.01)	0.01	11.96	32
33																33
34																34

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Proposed General Service Private Area Lighting (GS-PAL) Rate Summary

Line No.	Lamp Type	Size & Pole Type	Watts	Class	Note	Monthly kWh	BTGR	BTER	Proposed BTGR & BTER Rate	DEAA Rate	TRED Rate	EE Rate	REPR Rate	UEC Rate	Total All Components Rate	Line No.
9																9
10										[redacted]	$ 0.00068	$ 0.00086	$ (0.00039)	$ 0.00039		10
11																11
12	GS-PAL															12
13	Mercury Vapor	RATE A (Existing pole)	200W	CLS 10		73	$ 4.87	[redacted]	**$ 4.87**	$ -	$ 0.05	$ 0.06	$ (0.03)	0.03	$ 4.98	13
14	Mercury Vapor	RATE A (Existing pole)	200W	CLS 10		73	4.87	[redacted]	**4.87**	-	0.05	0.06	(0.03)	0.03	4.98	14
15	Mercury Vapor	RATE A (Existing pole)	200W	CLS 12		165	4.63	[redacted]	**4.63**	-	0.11	0.14	(0.06)	0.06	4.88	15
16	Mercury Vapor	RATE A (Existing pole)	200W	CLS 12		165	4.63	[redacted]	**4.63**	-	0.11	0.14	(0.06)	0.06	4.88	16
17	High Pressure	RATE A (Existing pole)	100W	CLS 14		42	4.98	[redacted]	**4.98**	-	0.03	0.04	(0.02)	0.02	5.05	17
18	High Pressure	RATE A (Existing pole)	100W	CLS 14		42	4.98	[redacted]	**4.98**	-	0.03	0.04	(0.02)	0.02	5.05	18
19	High Pressure	RATE A (Existing pole)	200W	CLS 15		83	4.94	[redacted]	**4.94**	-	0.06	0.07	(0.03)	0.03	5.07	19
20	High Pressure	RATE A (Existing pole)	200W	CLS 15		83	4.94	[redacted]	**4.94**	-	0.06	0.07	(0.03)	0.03	5.07	20
21	High Pressure	RATE A (Existing pole)	200W	CLS 88		165	4.62	[redacted]	**4.62**	-	0.11	0.14	(0.06)	0.06	4.87	21
22	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 11		73	12.02	[redacted]	**12.02**	-	0.05	0.06	(0.03)	0.03	12.13	22
23	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 13		165	11.77	[redacted]	**11.77**	-	0.11	0.14	(0.06)	0.06	12.02	23
24	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 13		165	11.77	[redacted]	**11.77**	-	0.11	0.14	(0.06)	0.06	12.02	24
25	High Pressure	RATE B (30 Foot pole)	100W	CLS 16		42	12.13	[redacted]	**12.13**	-	0.03	0.04	(0.02)	0.02	12.20	25
26	High Pressure	RATE B (30 Foot pole)	200W	CLS 17		83	12.09	[redacted]	**12.09**	-	0.06	0.07	(0.03)	0.03	12.22	26
27	High Pressure	RATE B (30 Foot pole)	200W	CLS 17		83	12.09	[redacted]	**12.09**	-	0.06	0.07	(0.03)	0.03	12.22	27
28	LED	RATE A (Existing pole)	200W	CLS 10		70	4.79	[redacted]	**4.79**	-	0.05	0.06	(0.03)	0.03	4.90	28
29	LED	RATE A (Existing pole)	200W	CLS 12		70	3.01	[redacted]	**3.01**	-	0.05	0.06	(0.03)	0.03	3.12	29
30	LED	RATE A (Existing pole)	100W	CLS 14		35	4.71	[redacted]	**4.71**	-	0.02	0.03	(0.01)	0.01	4.76	30
31	LED	RATE A (Existing pole)	200W	CLS 15		70	4.61	[redacted]	**4.61**	-	0.05	0.06	(0.03)	0.03	4.72	31
32	LED	RATE A (Existing pole)	200W	CLS 88		70	3.00	[redacted]	**3.00**	-	0.05	0.06	(0.03)	0.03	3.11	32
33	LED	RATE B (30 Foot pole)	200W	CLS 11		70	11.95	[redacted]	**11.95**	-	0.05	0.06	(0.03)	0.03	12.06	33
34	LED	RATE B (30 Foot pole)	200W	CLS 13		70	9.76	[redacted]	**9.76**	-	0.05	0.06	(0.03)	0.03	9.87	34
35	LED	RATE B (30 Foot pole)	100W	CLS 16		35	11.93	[redacted]	**11.93**	-	0.02	0.03	(0.01)	0.01	11.98	35
36	LED	RATE B (30 Foot pole)	200W	CLS 17		70	11.77	[redacted]	**11.77**	-	0.05	0.06	(0.03)	0.03	11.88	36
37																37
38																38

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Proposed Standby Rates

Line No.		Class	Distribution Charges: Distribution Charge, per Cust.	Distribution Charges: Additional Meter/ Generation Meter Charge[8]	Distribution Charges: Facilities Charge, per customer for SS-I and II, per kW for LSR and SSR-III[3]	Distribution Charges: Facilities Charge, per kW[2,3]	Contract Demand Charges, contract kW[4]: Sum On Peak:	Contract Demand Charges: Sum Mid Peak:	Contract Demand Charges: Other:	Backup Service Variable T&G Demand Charges, metered kW: Sum On Peak:	Backup: Sum Mid Peak:	Backup: Other:	BTGR Energy, per kWh (including interclass rate rebalancing)[5,6]: Sum On Peak:	BTGR: Sum Mid Peak:	BTGR: Sum Off Peak:	BTGR: Other:	Maintenance Back-up Service[7]: Set @ 50% of Summer On-peak Variable T&G Demand Charges	BTER Energy, per kWh	Line No.
9	SSR II	SS-II GS	25.50	2.50	4.74											0.01072		[redacted]	9
10	SSR III	LGS-1	15.80	6.25	3.68	$ 3.68			$ 1.00			$ 3.01				0.01522	$ 1.51	[redacted]	10
11	LSR I	LGS-2S	122.40	9.75	2.68	2.68	$ 3.20	$ 0.66	0.15	$ 9.61	$ 1.99	0.45	$ 0.03242	$ 0.01573	$ 0.00053	0.00572	4.81	[redacted]	11
12	LSR I	LGS-2P	207.70	65.00	2.34	2.34	2.65	0.62	0.15	7.94	1.85	0.45	0.03817	0.01763	0.00107	0.00464	3.97	[redacted]	12
13	LSR I	LGS-2T	182.00	23.00	CSF	0.61	2.87	0.67	0.19	8.59	2.00	0.56	0.04425	0.00766	0.00001	0.00066	4.30	[redacted]	13
14	LSR II	LGS-3S	122.00	3.00	2.82	2.82	3.11	0.75	0.20	9.33	2.25	0.60	0.03591	0.01718	0.00130	0.00483	4.67	[redacted]	14
15	LSR II	LGS-3P	214.10	76.25	2.73	2.73	3.40	0.84	0.21	10.21	2.52	0.64	0.03856	0.01300	0.00116	0.00279	5.11	[redacted]	15
16	LSR II[2]	LGS-3T	182.00	23.00	CSF	0.61	2.87	0.67	0.19	8.59	2.00	0.56	0.04425	0.00766	0.00001	0.00066	4.30	[redacted]	16
17	LSR III[9]	LGS-XS	4,743.00	20.52	0.91	0.91	3.11	0.75	0.20	9.33	2.25	0.60	0.03591	0.01718	0.00130	0.00483	4.67	[redacted]	17
18	LSR III[9]	LGS-XP	4,743.00	86.85	1.63	1.63	3.40	0.84	0.21	10.21	2.52	0.64	0.03856	0.01300	0.00116	0.00279	5.11	[redacted]	18
19	LSR III[1,9]	LGS-XT	4,743.00	139.05	CSF	-	2.87	0.67	0.19	8.59	2.00	0.56	0.04425	0.00766	0.00001	0.00066	4.30	[redacted]	19
20	LSR I WP	LGS-2-WPS	128.70	9.75	0.80	0.80	3.87	3.87	0.15	11.59	11.59	0.45	0.00010	0.00010	0.00001	0.00002	5.80	[redacted]	20
21	LSR I WP	LGS-2-WPP	208.60	65.00	1.17	1.17	3.27	3.27	0.15	9.79	9.79	0.45	0.05587	0.09974	0.00104	0.00105	4.90	[redacted]	21
22	LSR I WP	LGS-2-WPT	169.10	-	CSF	0.61	3.53	3.53	0.19	10.60	10.60	0.56	0.05435	0.10098	0.00117	0.00117	5.30	[redacted]	22
23	LSR II WP	LGS-3-WPS	149.90	3.00	0.45	0.45	3.86	3.86	0.20	11.58	11.58	0.60	0.00010	0.00010	0.00001	0.00002	5.79	[redacted]	23
24	LSR II WP	LGS-3-WPP	234.20	76.25	0.92	0.92	4.24	4.24	0.21	12.73	12.73	0.64	0.03723	0.06984	0.00080	0.00081	6.37	[redacted]	24
25	LSR II WP	LGS-3-WPT	189.10	23.00	CSF	0.61	4.35	4.35	0.21	13.07	13.07	0.64	0.03622	0.07071	0.00089	0.00090	6.53	[redacted]	25

note: while not shown in this table, DEAA is applicable to standby service.

1. CSF = customer specific facilities charges.
2. The facilities charge for SSR-I includes all of the cost-based Rule 9 facilities costs not recovered in the applicable customer charge and 10 percent of the cost-based primary distribution costs. SSR-II facilities recover the balance of the cost-based primary distribution costs not recovered in the applicable basic service charge. For SSR-III, LSR-I, LSR-II and LSR-III the facilities charge, if applicable, is the cost-based charge under the otherwise applicable rate schedule (OAS), or the CSF (see note 1 above). For most transmission-level customers, facilities charges do not apply, as they have no primary distribution costs and have typically funded their (Rule 9) extension costs. If facilities costs do apply, then they are custome
3. This is a lower, alternative facilities charge which recovers only the cost based (primary) distribution facilities costs applicable under the OAS. This lower charge is applicable when the customer has paid for the all of the costs of their interconnection facilities. This alternative facilities charge is not applicable to SSR I and SSR II, and is not applicable when a CSF charge applies instead.
4. The contract demand charge is set at 25% of current tariff demand charges in each rating period, reflecting the 3-year average diversity factor of all standby customers.
5. The BTGR for SSR-1 and SSR-II is adjusted downward from the BTGR charge of the OAS because a greater portion of facilities costs are being recovered from these customers on a per customer basis than is being recovered in the OAS. See note
6. Other than as explained in note 5, the BTGR rates are those of the otherwise applicable class including the IRR.
7. Energy rates in maintenance periods are the same as those during non-maintenance periods -- see BTGR and BTER columns for applicable rates.
8. SSR-I and SSR-II charges are the incremental cost based customer and meter charges associated with this standby service. For all other classes the charge is a per meter charge and recovers the cost-based meter costs and other associated cost
9. For the LGS-XS and LGS-XP customers, in addition to the per kW charges shown, they will also continue to pay the CSF charges that are currently applicable under the otherwise applicable LGS-X schedule. For the LGS-XT class, only CSF charge

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Proposed Distribution Only Service (DOS) Rates

Class	Note	Distribution Charge, per Customer	Total Facilities Charge, per kW (1)	Additional Meter Charge, per Meter	LGSX CSF Charges (monthly dollar charge for entire class)	Non-Bypassable Energy Charges Interclass Rate Rebalancing (IRR)
GS	1	$ 25.50		$ 2.50		$ 0.01131
LGS-1	1	15.80	$ 3.68	6.25		0.00178
LGS-2S		122.40	2.68	9.75		0.00110
LGS-2P		207.70	2.34	65.00		0.00001
LGS-2T	2	182.00	0.61	23.00		0.00178
LGS-3S		122.00	2.82	3.00		0.00066
LGS-3P		214.10	2.73	76.25		0.00001
LGS-3T	2	182.00	0.61	23.00		0.00001
LGS-XS	3	4,743.00	0.91	20.52	$ 1,608.00	0.00001
LGS-XP	3	4,743.00	1.63	86.85	$ 49,797.00	0.00131
LGS-XT	3	4,743.00	-	139.05	$ 29,105.00	0.00090
LGS-2S-WP		128.70	0.80	9.75		0.00001
LGS-2P-WP		208.60	1.17	65.00		0.00001
LGS-2T-WP	2	169.10	0.61	-		0.00001
LGS-3S-WP		149.90	0.45	3.00		0.00001
LGS-3P-WP		234.20	0.92	76.25		0.00001
LGS-3T-WP	2	189.10	0.61	23.00		0.00001
SL	4					
GS-Pal	4					

Additional Charges:

Separate Billing			
DOS LGS-X & LGS-WP-X:	$	93.50	Per additional bill
Power Factor Charges ($/kVarh)[5]:			
Summer:	$	0.00200	$/kVarh
Winter:		0.00100	$/kVarh
Non-X class Customer Specific Facilities:		0.00313	Per $ of Utility Investment
		0.00057	$ per Customer Contributed Investment
R-BTER - 2016 charge ($/kWh)[6]:		-	
R-BTER - 2017 charge ($/kWh)[6]:		-	

(1) The facilities charge is included in the per customer charge for the GS classes. For LGS-1, the charge is based on the kW monthly demand per meter. For all other customers, it is based on the highest measured demand in the billing period and the prior twelve billing periods. For non-transmission level customers and the non-LGSX customers, the facilities charges recover both the Rule 9 facility and primary distribution facilities costs.

(2) The non-LGSX transmission-level customers have customer specific facilities (CSF) charges, with the rate applied on per dollar of investment. CSF charges may apply to either the investment made by NPC in the customers facilities or the customer's contributed investment (for O&M recovery). The per kW rate shown in this table is the average per kW facility rate for the class as a whole for NPC-related facilities. This average per kW rate may be applied only to new customers on a temporary basis should the details of the facility calculations be incomplete at the start of service. All new, permanent customers served under these tariffs will be placed on a CSF charges as soon as reasonably practical.

(3) As in present rates, for the LGS-X class, the per kW distribution facility charge applies to only the LGSX-S and LGSX-P customers, who pay for their share of the primary distribution system through this charge. In addition to this charge, these customers continue to pay a CSFC based upon the cost of the facilities identified to serve them.

(4) RS-Pal is not eligible for DOS service. The Streetlights and GS-PAL proposed DOS rates are shown on pages 14 and 16 of Statement O.

(5) This charge is per kvarh in excess of 90% Power Factor (PF) for all classes except OLGS-3P HLF and LGS-X, which uses a 95% threshold. For all other classes the PF threshold is 90%.

(6) Rates do not apply to all DOS customers and are charged only to applicable customers.

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Summary of Incremental Price (IP) Generation Capacity Rates

Line No.		Class[1]	Sales (kWh)	Marginal Generation Revenue	Reconciled Generation Cost per kWh[2]	Line No.
8	**Bundled Service**					8
9		GS	584,168,954	$ 11,425,330	$ 0.01956	9
10		LGS-1	3,897,463,666	85,606,862	0.02196	10
11		LGS-2S	2,365,736,287	46,945,234	0.01984	11
12		LGS-2P	67,742,230	1,239,007	0.01829	12
13		LGS-2T	no customers	(set @ LGS-3T)	0.02373	13
14		LGS-3S	800,640,755	15,055,569	0.01880	14
15		LGS-3P	1,296,176,562	30,830,553	0.02379	15
16		LGS-3T	291,915,629	6,926,167	0.02373	16
17		LGS-XS	0	(set @ LGS-3S)	0.01880	17
18		LGS-XP	0	(set @ LGS-3P)	0.02379	18
19		LGS-XT	0	(set @ LGS-3T)	0.02373	19
20		LGS-2S-WP	6,831,160	161,762	0.02368	20
21		LGS-2P-WP	12,228,600	167,973	0.01374	21
22		LGS-2T-WP	no customers	(set @ LGS-3T)	0.02373	22
23		LGS-3S-WP	5,751,817	20,520	0.00357	23
24		LGS-3P-WP	17,504,868	188,297	0.01076	24
25		LGS-3T-WP	no customers	(set @ LGS-3T)	0.02373	25
26		SL	150,361,312	1,894,319	0.01260	26
27		GS-Pal	2,337,372	27,312	0.01168	27
28		IAIWP	no customers	(set @ LGS-3S)	0.02196	28
29						29
30	**Current LSR & Optional/Trial TOU Classes with Customers:**					30
31		LSR-1: LGS-2S		(set @ LGS-2S)	0.01984	31
32		LSR-1: LGS-2P		(set @ LGS-2P)	0.01829	32
33		LSR-1: LGS-2T		(set @ LGS-2T)	0.02373	33
34		LSR-2: LGS-3P		(set @ LGS-3P)	0.01880	34
35		LSR-2: LGS-3T		(set @ LGS-3T)	0.02373	35
36		LSR-2: LGS-3S-WP		(set @ LGS-3S-WP)	0.00357	36
37		LSR-2: LGS-3P-WP		(set @ LGS-3P)	0.01076	37
38		LSR-2: LGS-2S-WP		(set @ LGS-2S)	0.02368	38
39		OGS-TOU		(set @ GS)	0.01956	39
40		OLGS-1-TOU		(set @ LGS-1)	0.02196	40
41						41
42	**DOS Classes:**					42
43		DOS: GS		(set @ GS)	0.01956	43
44		DOS: LGS-1		(set @ LGS-1)	0.02196	44
45		DOS: LGS-2S		(set @ LGS-2S)	0.01984	45
46		DOS: LGS-3S		(set @ LGS-3S)	0.01880	46
47		DOS: LGS-3P		(set @ LGS-3P)	0.02379	47
48		DOS: LGS-3T		(set @ LGS-3T)	0.02373	48
49		DOS: LGS-2S-WP		(set @ LGS-2S-WP)	0.02368	49
50		DOS: LGS-2T-WP		(set @ LGS-2T-WP)	0.02373	50
51		DOS: LGS-3S-WP		(set @ LGS-3S-WP)	0.00357	51
52		DOS: LGS-3P-WP		(set @ LGS-3P-WP)	0.01076	52
53		DOS: LGS-3T-WP		(set @ LGS-3T-WP)	0.02373	53

54 54

55 1. Rates are shown only for classes containing customers with the potential of going open access under AB 661 or SB 211 provisions. 55

56 For customer served under DOS, LSR, OGS-TOU and OLGS-1-TOU, the applicable generation capacity rates will be set at those of an otherwise 56

57 applicable schedule (OAS). For these classes that presently have customers served, the applicable OAS is shown in the table. 57

58 2. This rate is the marginal generation cost reconciled to the generation revenue requirement stated on a per kWh basis for the class. 58

59 Reconciliation factor is: 100.0% 59

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Calculation of Customer Specific Facilities Charges

Line No.	Customer Specific Facility Investment & Revenue Requirement	Total	Line No.
7	Investment Cost for all Transmission level customers	$ 34,982,146	7
8	Total Annual Marginal Cost Revenue Requirement associated with the T-level customer specific investment	$ 1,155,018	8
9	Marginal Cost: $ of Revenue Req. per $ of Marginal Investment (line 8/line 7)	$ 0.03302	9
10	Distribution Reconciliation Factor	100.0%	10
11	Reconciled: Annual $ of Reconciled Revenue Req. per $ of Investment (line 9 * line 10)	$ 0.03754	11
12			12

Line No.	Individual CSFC	Class	Group	NVE Investment	Annual $ Per $ of Facility Investment	Annual Fac Rev By Customer	Monthly Per $ of Fac Invest. Factor	Monthly Fac Revenue By Customer	Line No.
13	**CSF Charges By Customer Per Dollar of Facilities Investment Factor Developed above**								13
17	LHOIST	LGS-3T	Bundled	$ 683,793	$ 0.03754	$ 25,683	$ 0.00313	$ 2,140.27	17
18	SA RECYCLING	LGS-3T	Bundled	1,255,444	0.03754	47,154	0.00313	3,929.54	18
19	VENETIAN	LGS-3T	Bundled	6,070,698	0.03754	228,015	0.00313	19,001.28	19
20	HOLDER	LGS-3T	Bundled	168,370	0.03754	6,324	0.00313	527.00	20
21	SNWA LAMB	LGS-3T	DOS	226,610	0.03754	8,511	0.00313	709.29	21
22	SNWA LAMB	LGS-3T	DOS	226,610	0.03754	8,511	0.00313	709.29	22
23	SNWA SLOAN	LGS-3T	DOS	573,573	0.03754	21,543	0.00313	1,795.28	23
24	CITY OF HENDERSON2	LGS-3T	DOS	474,810	0.03754	17,834	0.00313	1,486.16	24
25	CITY OF HENDERSON2	LGS-3T	DOS	474,810	0.03754	17,834	0.00313	1,486.16	25
26	CCWRD2	LGS-3T	DOS	71,248	0.03754	2,676	0.00313	223.01	26
27	CCWRD2	LGS-3T	DOS	40,278	0.03754	1,513	0.00313	126.07	27
28	CCWRD2	LGS-3T	DOS	446,751	0.03754	16,780	0.00313	1,398.33	28
29	MGM	LGS-3T	DOS	19,417,260	0.03754	729,312	0.00313	60,776.02	29
30	MGM	LGS-3T	DOS	1,317,659	0.03754	49,491	0.00313	4,124.27	30
31	CAESAR'S	LGS-3T	DOS	942,390	0.03754	35,396	0.00313	2,949.68	31
32	SNWA PP4	LGS-3T-WP	DOS	27,742	0.03754	1,042	0.00313	86.83	32
33	SNWA PP5	LGS-3T-WP	DOS	1,259,170	0.03754	47,294	0.00313	3,941.20	33
34	SNWA PP6	LGS-3T-WP	DOS	617,642	0.03754	23,199	0.00313	1,933.22	34
35	SNWA HACIENDA	LGS-3T-WP	DOS	300,574	0.03754	11,290	0.00313	940.80	35
36	SNWA PP3	LGS-2T-WP	DOS	386,714	0.03754	14,525	0.00313	1,210.41	36
37	CLEARWATER PAPER CORPORATION	OLGS-3P HLF	Bundled	1,478,462	0.03754	55,531	0.00313	4,627.59	37
38	NP RED ROCK LLC	OLGS-3P HLF	Bundled	636,335	0.03754	23,901	0.00313	1,991.73	38
39	POLY-WEST INC	OLGS-3P HLF	Bundled	204,283	0.03754	7,673	0.00313	639.41	39
40	STATION GVR ACQUISITION LLC	OLGS-3P HLF	Bundled	288,821	0.03754	10,848	0.00313	904.01	40
41	TRUMP RUFFIN COMMERCIAL LLC	OLGS-3P HLF	Bundled	921,045	0.03754	34,594	0.00313	2,882.87	41
42	SUNSET STATION 1641830	OLGS-3P HLF	Bundled	398,394	0.03754	14,964	0.00313	1,246.97	42
43	STRATOSPHERE CORPORATION	OLGS-3P HLF	Bundled	538,517	0.03754	20,227	0.00313	1,685.56	43
44	STRATOSPHERE CORPORATION	OLGS-3P HLF	Bundled	447,097	0.03754	16,793	0.00313	1,399.42	44
45	POLY-WEST 2089379	OLGS-3P HLF	Bundled	204,283	0.03754	7,673	0.00313	639.41	45
46									46
47									47
48									48
49									49
50	Subtotals by Class and Service								50
51	LGS-3T - Bundled	LGS-3T	Bundled	$ 6,178,305	0.03754	307,177	0.00313	25,598	51
52	LGS-3T - DOS	LGS-3T	DOS	24,211,999	0.03754	909,403	0.00313	75,784	52
53	LGS-2T-WP - Bundled	LGS-2T-WP	Bundled	-	0.03754	-	0.00313	-	53
54	LGS-2T-WP - DOS	LGS-2T-WP	DOS	386,714	0.03754	14,525	0.00313	1,210	54
55	LGS-3T-WP - Bundled	LGS-3T-WP	Bundled	-	0.03754	-	0.00313	-	55
56	LGS-3T-WP - DOS	LGS-3T-WP	DOS	2,205,128	0.03754	82,825	0.00313	6,902	56
57	OLGS-3P-HLF Bundled	OLGS-3P HLF	Bundled	5,117,238	0.03754	192,203	0.00313	16,017	57
58					avg.		avg.		58
59	Total			$ 40,099,384	0.03756	$ 1,506,133	0.00313	$ 125,511	59
60					rounding>>	$ 0		$ 0	60

Line No.	Temporary Transmission level per kW Facility Charge (Charged until CSF charge is developed)			Line No.
61			^^^^^^^^^^^^	61
62			Proposed	62
63	Investment Cost for Transmission level customers:	$ 34,982,146	Tariff Recovery	63
64	Total Annual Marginal Cost Revenue Requirement associated with the customer specific investment (line 63 * line 11):	$ 1,155,018	Rate per Dollar	64
65	Distribution Reconciliation Factor (line 11):	100.0%	of Facility	65
66	Reconciled Investment Cost (line 65 * line 64):	$ 1,155,018	Investment	66
67	Annual facility kW determinants	1,560,404		67
68	Per kW facilty rate (line 66 / Line 67)	$ 0.61		68

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Calculation of Transmission Level Customer Specific Facilities O&M and A/G Customer Specific Rates Relating to Contributed (CIAC) Investment

Development of Annual & Monthly Per Dollar of Investment Recovery Rate

	(a)		(b)		(c)
Annual: Dist Reconciliation Factor	x	Dollar O&M/A&G Recovery Per Dollar of Contributed Investment			
100.0%	x		$0.00992	=	$ 0.00992
Monthly: (annual rate divided by 12)				=	$ 0.00057

CIAC Investment & O&M and A&G Revenue Requirement

Customer	Class	Group	Contributed Investment	Annual Revenue Requirement	Dollar Per Dollar of Investment $ (cost based -- before reconciliation) [(b) / (a)]	Per Dollar O&M/A&G Recovery Per Dollar of CIAC'd Facility Investment & Charges by Customer: Original CIAC Investment	Monthly Per $ of CIAC'd Investment	Monthly Payment [(d) * (e)]	Annual Payment
LHOIST	LGS-3T	Bundled	-	$ -	$0.00992	$ -	$ 0.00057	$ -	$ -
SA RECYCLING	LGS-3T	Bundled	-	-	$0.00992	-	0.00057	-	-
VENETIAN	LGS-3T	Bundled	-	-	$0.00992	-	0.00057	-	-
HOLDER	LGS-3T	Bundled	11,791,553	117,025	$0.00992	11,791,553	0.00057	6,721.19	80,654.28
SNWA LAMB	LGS-3T	DOS	453,810	4,504	$0.00992	453,810	0.00057	258.67	3,104.04
SNWA LAMB	LGS-3T	DOS	453,810	4,504	$0.00992	453,810	0.00057	258.67	3,104.04
SNWA SLOAN	LGS-3T	DOS	826,580	8,203	$0.00992	826,580	0.00057	471.15	5,653.80
CITY OF HENDERSON2	LGS-3T	DOS	1,191,000	11,820	$0.00992	1,191,000	0.00057	678.87	8,146.44
CITY OF HENDERSON2	LGS-3T	DOS	1,191,000	11,820	$0.00992	1,191,000	0.00057	678.87	8,146.44
CCWRD2	LGS-3T	DOS	374,615	3,718	$0.00992	374,615	0.00057	213.53	2,562.36
CCWRD2	LGS-3T	DOS	211,779	2,102	$0.00992	211,779	0.00057	120.71	1,448.52
CCWRD2	LGS-3T	DOS	2,348,976	23,312	$0.00992	2,348,976	0.00057	1,338.92	16,067.04
MGM	LGS-3T	DOS	-	-	$0.00992	-	0.00057	-	-
MGM	LGS-3T	DOS	-	-	$0.00992	-	0.00057	-	-
CAESAR'S	LGS-3T	DOS	-	-	$0.00992	-	0.00057	-	-
SNWA PP4	LGS-3T-WP	DOS	-	-	$0.00992	-	0.00057	-	-
SNWA PP5	LGS-3T-WP	DOS	-	-	$0.00992	-	0.00057	-	-
SNWA PP6	LGS-3T-WP	DOS	-	-	$0.00992	-	0.00057	-	-
SNWA HACIENDA	LGS-3T-WP	DOS	-	-	$0.00992	-	0.00057	-	-
SNWA PP3	LGS-2T-WP	DOS	-	-	$0.00992	-	0.00057	-	-
CLEARWATER PAPER CORPORATION	OLGS-3P HLF	Bundled	-	-	$0.00992	-	0.00057	-	-
NP RED ROCK LLC	OLGS-3P HLF	Bundled	-	-	$0.00992	-	0.00057	-	-
POLY-WEST INC	OLGS-3P HLF	Bundled	51,773	514	$0.00992	51,773	0.00057	29.51	354.12
STATION GVR ACQUISITION LLC	OLGS-3P HLF	Bundled	-	-	$0.00992	-	0.00057	-	-
TRUMP RUFFIN COMMERCIAL LLC	OLGS-3P HLF	Bundled	-	-	$0.00992	-	0.00057	-	-
SUNSET STATION 1641830	OLGS-3P HLF	Bundled	-	-	$0.00992	-	0.00057	-	-
STRATOSPHERE CORPORATION	OLGS-3P HLF	Bundled	-	-	$0.00992	-	0.00057	-	-
STRATOSPHERE CORPORATION	OLGS-3P HLF	Bundled	-	-	$0.00992	-	0.00057	-	-
POLY-WEST 2089379	OLGS-3P HLF	Bundled	51,773	514	$0.00992	51,773	0.00057	29.51	354.12
Subtotals by Class and Service									
LGS-3T - Bundled	LGS-3T	Bundled	11,791,553	117,025	$0.00992	11,791,553	0.00057	6,721.19	80,654.28
LGS-3T - DOS	LGS-3T	DOS	7,051,570	69,983	$0.00992	7,051,570	0.00057	4,019.39	48,232.68
LGS-2T-WP - Bundled	LGS-2T-WP	Bundled	-	-	$0.00992	-	0.00057	-	-
LGS-2T-WP - DOS	LGS-2T-WP	DOS	-	-	$0.00992	-	0.00057	-	-
LGS-3T-WP - Bundled	LGS-3T-WP	Bundled	-	-	$0.00992	-	0.00057	-	-
LGS-3T-WP - DOS	LGS-3T-WP	DOS	-	-	$0.00992	-	0.00057	-	-
OLGS-3P-HLF Bundled	OLGS-3P HLF	Bundled	103,546	1,028	$0.00992	103,546	0.00057	59.02	708.24
Total			$ 18,946,669	$ 188,036	$0.00992	$ 37,893,338		$ 10,799.60	$ 129,595.20
					Marginal O&M from MCS $188,036				

Nevada Power Company
Statement O

Settlement Statement O
Docket No. 20-06003

Calculation of LGS-X Specific Charges

Line No.		Basic Service Charge			Additional Meter Charge			Separate Bill			Line No.
7	**Basic Service, Additional Meter and Separate Billing Charges**										7
8											8
9		Basic Service Charge			Additional Meter Charge			Separate Bill			9
10		Billing Units	Cost-Based Revenue	Rate	Billing Units	Cost-Based Revenue	Rate	Billing Units	Cost-Based Revenue	Rate	10
11	LGS-XS	-	$ -		60	$ 1,362.75	$ 22.70	-	$ -		11
12	LGS-XP	24	$ 1,244,282.46	$ 51,845.10	156	$ 6,262.71	$ 40.10	24	$ 630.43	$26.27	12
13	LGS-XT	12	$ 363,617.42	$ 30,301.45	36	$ 756.91	$ 21.00	12	$ 157.61	$13.13	13
14	Total	36	$ 1,607,899.88	$4,743.00	252	$ 8,382.37	$33.30	36	$ 788.03	$93.50	14
15			Present DOS Rate:	$5,580.00					Present Rate:	$110.00	15
16			Percent Change:	-15.0%					Percent Change:	-15.0%	16
17											17

Line No.	Customer	Premise	Rate Schedule	Current Charges: Monthly Facilities Charge	Current Charges: Annual Facilities Revenue	Current Charges: Investment	Proposed Charges: Monthly Facilities Charge	Proposed Charges: Annual Facilities Revenue	Proposed Charges: Investment	Line No.
18	**LGS-X Customer Specific Facilities**									18
19										19
20				Current Charges			Proposed Charges			20
21	Customer	Premise	Rate Schedule	Monthly Facilities Charge	Annual Facilities Revenue	Investment	Monthly Facilities Charge	Annual Facilities Revenue	Investment	21
22	Bally	1231089	LGS-XP DOS	$ 4,228	$ 50,736		$ 3,740	$ 44,880		22
23	Bally	1231091	LGS-XS DOS	1,818	21,816		1,608	19,296		23
24	Paris	1735149	LGS-XP DOS	5,729	68,748		5,068	60,816		24
25	Paris	1735152	LGS-XP DOS	5,729	68,748		5,068	60,816		25
26				$ 17,504	$ 210,048	$ 2,020,383	$ 15,484	$ 185,808	$ 2,066,291	26
27										27
34	New Castle Corp (Excalibur)	1398169	LGS-XP DOS	$ 5,257	$ 63,084		$ 4,710	$ 56,520		34
35	New Castle Corp (Excalibur)	1396170	LGS-XP DOS	5,232	62,784		4,687	56,244		35
36	New Castle Corp (Excalibur)	1415346	LGS-XS DOS	-	-		-	-		36
37	New Castle Corp (Excalibur)	1415347	LGS-XS DOS	-	-		-	-		37
38	Luxor	1500684	LGS-XP DOS	6,295	75,540		5,640	67,680		38
39	Luxor	1500685	LGS-XP DOS	7,820	93,840		7,006	84,072		39
40	Luxor	1511139	LGS-XS DOS	-	-		-	-		40
41	Luxor	1652129	LGS-XP DOS	1,895	22,740		1,698	20,376		41
42	Mandalay Bay	1714502	LGS-XP DOS	6,798	81,576		6,090	73,080		42
43	Mandalay Bay	1714503	LGS-XP DOS	6,798	81,576		6,090	73,080		43
44	New Castle Corp (Excalibur)	1758368	LGS-XP DOS	-	-		-	-		44
45				$ 40,095	$ 481,140	$ 4,885,159	$ 35,921	$ 431,052	$ 4,885,159	45
46										46
47	Monte Carlo	1607748	LGS-XT DOS	$ -	$ -		$ -	$ -		47
48	Monte Carlo	1607750	LGS-XT DOS	10,739	128,868		9,790	117,480		48
49	Bellagio	1656755	LGS-XP DOS	-	-		-	-		49
50	Bellagio	1656777	LGS-XP DOS	-	-		-	-		50
51	Bellagio	1693991	LGS-XT DOS	21,186	254,232		19,315	231,780		51
52	Monte Carlo	1782548	LGS-XP DOS	-	-		-	-		52
53				$ 31,925	$ 383,100	$ 3,727,626	$ 29,105	$ 349,260	$ 3,727,626	53
54										54
55		Subtotals by Class and Service	LGS-XS	$ -	$ -	$ -	$ -	$ -	$ -	55
56			LGS-XP	-	-	-	-	-	-	56
57			LGS-XT	-	-	-	-	-	-	57
58			LGS-XS DOS	**1,818**	**21,816**	-	**1,608**	**19,296**	-	58
59			LGS-XP DOS	**55,781**	**669,372**	-	**49,797**	**597,564**	-	59
60			LGS-XT DOS	**31,925**	**383,100**	-	**29,105**	**349,260**	-	60
61			Total for Class	$ 89,524	$ 1,074,288	$ -	$ 80,510	$ 966,120	$ -	61
62										62

63 Note: The allocation of CSFC's among accounts was done by keeping the Transmission & Secondary charges the same as Current (Since the underlying investment has remained the same), and allocating the Primary Charges in proportion to the current 63
64 Primary charges. 64

NVEnergy

September 24, 2020

Ms. Trisha Osborne, Assistant Commission Secretary
Public Utilities Commission of Nevada
Capitol Plaza
1150 East William Street
Carson City, Nevada 89701-3109

RE: Docket No. 20-06003: Application of Nevada Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto.

Dear Ms. Osborne:

Pursuant to the filing made this afternoon by Nevada Power Company d/b/a NV Energy, attached is Mr. Lucas Foletta's signature page.

Should you have any questions regarding this filing, please contact me at (775) 834-4261 or ldinnocenti@nvenergy.com.

Respectfully submitted,

/s/Lynn D'Innocenti
Lynn D'Innocenti
Sr. Legal Administrative Assistant

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

This Stipulation is entered into by each Signatory as of the date entered below:

NEVADA POWER COMPANY
d/b/a NV ENERGY

Date

By: Michael Greene, Esq.
Deputy General Counsel

REGULATORY OPERATIONS STAFF OF THE PUBLIC UTILITIES COMMISSION OF NEVADA

Date

By: Shelly Cassity, Esq.
Assistant Staff Counsel
Jesse Panoff, Esq.
Assistant Staff Counsel

BUREAU OF CONSUMER PROTECTION

Date

By: Michael Saunders, Esq.
Senior Deputy Attorney General

MGM RESORTS INTERNATIONAL

9-24-20
Date

By: Fred Schmidt, Esq.
Austin Jensen, Esq.

CAESARS ENTERPRISE SERVICES

9-24-20
Date

By: Fred Schmidt, Esq.
Austin Jensen, Esq.

SOUTHERN NEVADA GAMING GROUP

9-24-20
Date

By: Lucas Foletta, Esq.

Appendix 7a

NV Energy Supporting Documentation (01/30/2023)

NV Energy

January 30, 2023

Mr. Ted Lendis
Permitting Manager
Clark County Department of Environmental and Sustainability, Division of Air Quality
4701 W. Russel Road, Suite 200
Las Vegas, Nevada 89118

RE: RACT Analyses Request for Supporting Documentation
Clark Generating Station (Source: 7) & Sun Peak Generating Station (Source: 423)

Dear Mr. Lendis:

Per the email dated December 21, 2022, from Rob Barton of RTP, Air Quality's consultant, to NV Energy (NVE) requesting response to additional questions and supporting documentation related to the Reasonably Available Control Technology Analyses for the Clark Generating Station (Source: 7) and Sun Peak Generating Station (Source: 423) previously submitted by NVE on October 3, 2022, NVE hereby submits the attached supplemental information.

NVE anticipates further communication from DAQ on this topic in the near future. If you require additional information or have any questions, please contact Sean Spitzer at (702) 402-5132, or via email at sean.spitzer@nvenergy.com.

I certify that, based on the information and belief formed after reasonable inquiry, the statements and information in this document are true, accurate, and complete.

Sincerely,

Jason Hammons
Vice President, Generation
NV Energy
Responsible Official

Q1: Provide documentation for the vendor cost estimates provided in Table 4-1 of the RACT Analysis for NOx control options for Clark Generating Station Unit 4.

A1: Table 4-1 of the RACT Analysis summarizes the estimated economic impact of three nitrogen oxide (NOx) control alternatives for Clark Generating Station Unit 4: selective catalytic reduction (SCR) plus dry low NOx (DLN) combustors, SCR alone, and DLN combustors alone. Detailed information about the cost of each alternative was provided in Appendix B of the analysis. The cost information presented in Appendix B and summarized in Table 4-1 is based on equipment quotations received from CECO/Peerless (for SCR) and General Electric (for DLN combustors). Copies of the vendor quotations that were received are provided with this letter in Attachment 1: Vendor Cost Information. Also included in Attachment 1 are copies of the response that was received from CECO/Peerless when NVE requested clarification about certain aspects of their equipment quotations, and an explanation about how the various cost elements used in Appendix B were derived from the information provided by CECO/Peerless and GE.

"Unit A" in the Budgetary Price Summary provided by CECO/Peerless corresponds to Clark Station Unit 4. Note that the emission control system that the vendor quoted is a combined SCR/oxidation catalyst system. Equipment and installation costs for a stand-alone SCR system were subsequently derived using the budgetary price summary and clarifications to it that the vendor provided. Items 1 and 2 of Attachment 2: Workup of Vendor Cost Information show how the SCR equipment and installation costs were derived from the vendor's budget quote and other information provided. Item 3 of this attachment shows how the annual SCR catalyst replacement cost estimate was developed.

GE provided a total installed cost estimate for retrofitting Clark Station Unit 4 with DLN combustors. Item 4 of Attachment 2 shows that the midpoint of the range of GE's estimated costs was used for the total installed cost estimate for the DLN combustor alternative for Unit 4.

Q2: Provide documentation for the vendor cost estimates provided in Table 5-1 of the RACT Assessment for VOC control options for Clark Generating Station Unit 4.

A2: Table 5-1 of the RACT analysis summarizes the estimated economic impact associated with controlling VOC emissions from Clark Generating Station Units 4 – 8 by retrofitting them with oxidation catalyst systems. Cost estimate details for each unit were provided in Appendix B to the RACT analysis. The basis for this cost information was the quotation received from CECO/Peerless and has been provided in Attachment 1.

"Unit C" in the vendor's Budgetary Price Summary corresponds to Clark Station Units 5 - 8. "Unit A" in the vendor's price summary corresponds to Clark Station Unit 4, although as described above the vendor did not supply a stand-alone equipment cost estimate for retrofitting an oxidation catalyst system onto Unit 4. Accordingly, an equipment cost estimate for Unit 4 was developed using the cost information that was supplied for Units 5 – 8, as detailed in Item 5 of Attachment 2. For this estimate the "six-tenths" scaling factor methodology described on page 25-16 of Perry

& Chilton's Chemical Engineer's Handbook (fifth edition) was used to estimate the cost of an oxidation catalyst system for Unit 4 based on the cost estimate provided for the slightly larger Units 5 – 8.

Items 6 and 7 of Attachment 2 show how the oxidation catalyst system installation cost estimate and annual catalyst replacement cost estimate for Clark Unit 4 were derived.

Q3: Provide information about the technical feasibility of Clark Generating Station Unit 4 meeting a VOC emission limit in the range of 1 – 3 ppmvd @ 15% O_2 based on good combustion practices.

A3: NVE asked GE about the technical feasibility of Clark Station Unit 4 meeting a VOC emission limit in the range of 1 – 3 ppmvd @ 15% O_2 without utilizing an oxidation catalyst system. We were informed that this emission level is not feasible with the combustor that is currently installed on the unit, and that because of its age (Unit 4 went into service in 1973) an engineering study would need to be performed to ascertain whether a VOC emissions limit lower than the current emissions level (0.024 lb/MMBtu) would be feasible.

Q4: Provide the equivalent stack concentration (expressed as ppmvd @ 15% O_2) used to derive the VOC emission limit of 5.01 lb/hr for Clark Generating Station Units 5 – 8.

A4: The operating permit for Clark Station contains no concentration-based VOC emission limits for Units 5 – 8. Rather, the mass emission limit of 5.01 lb/hr for each unit shown in Table III-C-2 of the facility's permit represents their only short-term limitation on VOC emissions. Documentation as to the concentration basis of this mass limit is not available. Nonetheless, using the maximum heat input rate of each unit (1,081 MMBtu/hr) and EPA's published F-factor for natural gas firing (8,710 dscf/MMBtu, per 40 CFR 60 Appendix A, Method 19), a mass limit of 5.01 lb/hr converts to a stack concentration of 1.3 ppmvd @ 15% O_2, as propane or 3.6 ppmvd @ 15% O_2, as methane.

Q5: Provide documentation for the vendor performance estimates provided in Appendix B for selective catalytic reduction (2 ppm @ 15% O_2) and dry low NOx combustors (9 ppm @ 15% O_2) for Sun Peak Generating Station Units 3 – 5.

A5: As summarized in Section 4-4 of the RACT Analysis, the results of the RACT/BACT/LAER Clearinghouse (RBLC) search that was conducted for this effort show that natural gas-fired simple-cycle combustion turbines equipped with SCR and DLN combustors have NOx emission limits in the range of 2 – 5 ppmv @ 15% O_2. Accordingly, NVE requested that the vendor's SCR equipment cost quote be based on a system sized to provide a stack concentration of 2 ppmv NOx @ 15% O_2. The RBLC search found that units equipped with DLN combustors alone have limits in the range of 9 – 30 ppmv @ 15% O_2, and accordingly 9 ppm NOx @ 15% O_2 was used as the equipment performance basis in the cost effectiveness calculations for this alternative.

Q6: Provide documentation for the vendor cost estimates provided in Tables 4-2 through 4-4 for the NOx control options for the Sun Peak Generating Station Units 3-5.

A6: Tables 4-2 through 4-4 of the RACT analysis summarize the estimated economic impact of alternative NOx controls for the Sun Peak Generating Station Units 3 - 5; detailed cost information about each alternative was provided in Appendix B of the analysis. Like the cost estimates for Clark Station Unit 4, the basis of the cost information presented in Appendix B and summarized in these tables for Sun Peak Units 3 – 5 are the SCR equipment quotation received from CECO/Peerless and the dry low NOx combustor cost information received from GE; copies of the vendor information received are provided in Attachment 1 to this letter. "Unit B" in the Budgetary Price Summary provided by CECO Peerless corresponds to Sun Peak Station Units 3- 5, and Items 8, 9 and 10 on Attachment 2 describe how the SCR equipment cost, installation cost, and SCR catalyst replacement cost (respectively) were derived from the vendor-provided information. Item 11 describes how the midpoint of the range of GE's estimated costs was used for the total installed cost estimate for the DLN combustor alternative for Units 3 – 5.

Q7: Provide information about the technical feasibility of Sun Peak Generating Station Units 3 – 5 meeting a NOx emission limit of 25 ppmvd @ 15% O_2 based on water injection and good combustion practices.

A7: NVE asked GE whether it would be technically feasible for the Sun Peak Units 3 – 5 to meet a NOx emission limit of 25 ppmv @ 15% O_2 using water injection and good combustion practices. We were informed that the combustors that are currently installed on these units are not capable of meeting this emission level. GE stated that these units would need to be retrofitted with new combustors for them to achieve 25 ppmv NOx @ 15% O_2 using water injection and that operating them at the water injection rate needed to meet this emission level could be expected to cause the units to emit carbon monoxide at a much higher level than they do currently.

Attachment 1:
Vendor Cost Information

CECO ENVIRONMENTAL
Peerless

Peerless Manufacturing Co (PMC)
CECO SCR Technologies
14651 North Dallas Parkway
Suite 500
Dallas, TX 75254
Ph. (214) 357-6181
Fax. (214) 351-0194

August 31, 2022

Steve Jelinek, PE
Senior Process Engineer
Steve.jelinek@aecom.com
AECOM
Office: (978) 905-2256

Subject: Budgetary Cost Estimate for SCR/CO Systems for a 60 and 85 MW Simple Cycle Combustion turbine

Dear Steve,

We are pleased to provide this proposal for the design and supply of various retrofit options for your client's Simple-Cycle and Combined-Cycle gas turbine exhaust systems in located in Nevada.

Best Regards,

Vaughn Watson
Director, Power Retrofit
(214) 668-1014
vwatson@onececo.com

I. BUDGETARY PRICE SUMMARY/SCOPE OF SUPPLY:

A. COMPLETE SIMPLE CYCLE SCR & CO/VOC EXHAUST SYSTEM FOR "UNIT A": A 1974 GENERAL ELECTRIC 7B (7000) TURBINE (60 MW) OPERATING IN SIMPLE-CYCLE PEAKING SERVICE (PRESSURE DROP GUARANTEE = 12" W.C.)

ITEM	QUANTITY	DESCRIPTION	PRICE
A	1	GT Outlet Expansion Joint	
B	1	Reactor Housing (includes access ladders and platforms)	
C	1	Flow Distribution/Mixing Device	
D	1	Outlet transition ductwork	
E	1	Expansion joint at stack	
F	1	Aqueous Ammonia Flow Control Unit	
G	1	Interconnecting piping from AFCU to manifold, manifold to AIG	
H	1	Ammonia Distribution Manifold	
I	1	Peerless EDGE™ - Ammonia Injection Grid	
J	1	SCR Catalyst – 120ppm > 4ppm - 96% NOx reduction; 10ppm NH3 slip	
K	1	SCR Catalyst Support Structure and Seals	
L	1	CO/VOC Catalyst	
M	1	CO Catalyst Support Structure and Seals	
N	1	Stack	
O	1	Acoustical Stack Silencer Baffles	
P	1	Stack Expansion Joint	
Q	1	Ammonia Storage Tank	
R	1	Ammonia Forwarding Pump Skid	
S	1	Ammonia Truck Unloading Skid	
T	Lot	Interconnecting Piping	
U	-	Engineering	
V	1	Computational fluid dynamics modeling	
W	1	Start-up and commissioning spares	
X	1	2 X 100% Tempering air / purge fan system	
Y	1	Freight	
		TOTAL BUDGET PRICE FOR ONE (1) SCR/CO/VOC SYSTEM	$ 11,000,000
O1	**1**	Budget Estimate for Mechanical Installation and Erection of Exhaust System (Excluding Civil, Electrical/Controls Integration & Piping Insulation)	**$7,625,000**

B. COMPLETE SIMPLE CYCLE SCR EXHAUST SYSTEM FOR "UNIT B": A 1991 GENERAL ELECTRIC PG7111-EA (84.5 MW) OPERATING IN SIMPLE CYCLE PEAKING SERVICE (PRESSURE DROP GUARANTEE = 12" W.C.)

ITEM	QUANTITY	DESCRIPTION	PRICE
A	1	GT Outlet Expansion Joint	
B	1	Reactor Housing (includes access ladders and platforms)	
C	1	Flow Distribution/Mixing Device	
D	1	Outlet transition ductwork	
E	1	Expansion joint at stack	
F	1	Aqueous Ammonia Flow Control Unit	
G	1	Interconnecting piping from AFCU to manifold, manifold to AIG	
H	1	Ammonia Distribution Manifold	
I	1	Peerless EDGE™ - Ammonia Injection Grid	
J	1	SCR Catalyst – 42ppm > 2ppm - 95% NOx reduction; 5ppm NH3 slip	
K	1	SCR Catalyst Support Structure and Seals	
L	1	Stack	
M	1	Acoustical Stack Silencer Baffles	
N	1	Stack Expansion Joint	
O	1	Ammonia Storage Tank	
P	1	Ammonia Forwarding Pump Skid	
Q	1	Ammonia Truck Unloading Skid	
R	Lot	Interconnecting Piping	
S	-	Engineering	
T	1	Computational fluid dynamics modeling	
U	1	Start-up and commissioning spares	
V	1	2 X 100% Tempering air / purge fan system	
W	1	Freight	
		TOTAL BUDGET PRICE FOR ONE (1) SCR SYSTEM	$ 12,500,000
O1	1	Budget Estimate for Mechanical Installation and Erection of Exhaust System (Excluding Civil, Electrical/Controls Integration & Piping Insulation)	**$8,500,000**

C. COMBINED-CYCLE RETROFIT CO/VOC CATALYST SYSTEM FOR UNIT C: A LATE 1970S WESTINGHOUSE MODEL 501B6 (85 MW) COMBINED CYCLE TURBINE

ITEM	QUANTITY	DESCRIPTION	PRICE
A	1	Reactor Housing (includes access ladders and platforms)	
B	1	Flow Distribution/Mixing Device/Transitions (As Required)	
C	1	CO/VOC Catalyst	
D	1	CO Catalyst Support Structure and Seals	
E	-	Engineering	
F	-	Computational fluid dynamics modeling	
G	1	Start-up and commissioning spares	
H	1	Freight	
		TOTAL BUDGET PRICE FOR ONE (1) RETROFIT CO/VOC SYSTEM	$ 2,500,000
01	1	Budget Estimate for Mechanical Installation and Erection of Exhaust System ***ASSUMES ADEQUATE SPACE BETWEEN SUPERHEATER/EVAPORATOR SECTION (TEMP RANGE OF 700-1000F.***	**$1,500,000**

All Purchase Orders based on this Quote, which is not an offer, are subject to acceptance by Seller at its principal office in Dallas, Texas. Unless otherwise expressly provided in Seller's acceptance, the terms and conditions set forth herein shall constitute a part of any agreement resulting from Seller's acceptance of an order for all or part of the goods covered by this Quote. This Quote serves as notice to Buyer of Seller's objection to any terms and conditions of Buyer that in any way conflict with, modify, condition, add to, or differ from the terms and conditions specified herein, unless such terms and conditions of Buyer are expressly included in Seller's acceptance of Buyer's order. Silence on the part of Seller shall not be construed, under any circumstances, as acceptance of Buyer's terms and conditions. If not previously revoked or otherwise provided herein, this Quote shall terminate and cease to exist thirty (30) days from the date of this Quote.

D. COMMERCIAL TERMS

A. PROPOSAL PRICE: The price proposed is for the design, materials, or components listed. If specific design conditions differ from the inquiry, the specifications shall be modified and an equitable adjustment shall be made in the contract price or delivery schedule, or both. Any changes in this quotation will be submitted and approved in writing.

B. DELIVERY: Typical delivery for all equipment is within FIFTY (50) weeks from the order date, contingent upon the timely return of approved drawings/documents. Storage fees will be charged if delivery is delayed beyond the project schedule for delays not caused by Peerless Mfg. Co. (Peerless). These charges will be imposed at the time of the delay.

C. TRANSPORTATION: Shipment of the equipment shall be via Motor Freight, DAP Job Site.

D. EXCLUDED ITEMS: The quoted price does not include any custom duties, tariffs, import fees, income tax, nor any other taxes, duties, levies, etc., imposed by governmental organizations. Equipment delivered to the following states will require a Tax Exemption Certificate to exclude those current state taxes from our invoice: Arizona, California, Georgia, Kentucky, Tennessee, and Texas.

E. VALIDITY: The offered price is valid for thirty (30) days from the proposal date, and thereafter, is subject to our acceptance. Due to the current fluctuation in steel prices, all pricing in this proposal must be confirmed at time of purchase order.

F. PAYMENT TERMS: Payment shall be made, net 30 days, per the following schedule:

25% - upon receipt of order
25% - upon submittal of approval drawings
25% - upon Peerless' Release for Procurement
15% - upon Delivery of Equipment
10% - upon Final Acceptance

G. CHANGES / CANCELLATION SCHEDULE: Any changes to or cancellation of the Agreement, once accepted, are subject to written approval by Peerless under conditions that shall include, among other things, protection against any loss to Peerless.

Cancellation Schedule:
25% - after receipt of purchase order
50% - after submittal of general arrangement drawings
90% - after release to purchase materials
100% - upon release to fabricate

H. WARRANTY: All hardware is under warranty for eighteen (18) months from contracted delivery or twelve (12) months from scheduled start-up, whichever occurs first. The extent of the warranty includes replacement of defective components and is limited to material only.

Peerless is not responsible for any damage resulting from mis-operation or improper maintenance of the unit as described in the Peerless Operation & Maintenance Manuals for this project. Warranty is voided if the system is not operated and maintained in accordance with the Operation & Maintenance Manual.

The aqueous ammonia must be reagent grade, diluted with fully de-ionized water to 19% by weight.

I. **PROPRIETARY RIGHTS:** All engineering and application information given in Peerless' Proposal is proprietary. Such information is to be used only in the evaluation of this offer. If an order does not result from this Proposal, such proprietary information must be held in confidence, and never used in any manner by the prospective purchaser.

If an order results from the Proposal, such proprietary information becomes the property of the Purchaser for use in the design, manufacture, and operation of the specific unit proposed, and cannot be used on any other item or in any other manner without approval from Peerless.

K. **NON-UNION LABOR:** Peerless labor facilities are non-union. Non-union craft will complete all fabrication work.

DESIGN CRITERIA

A. Design Conditions: The proposed SCR System design is based on the following design conditions; the data is for one (1) unit. Should the actual gas conditions be different from the design data, the performance shall be re-evaluated, based on the corrected design data.

Unit A: A 1974 General Electric 7B (7000) turbine (60 MW) operating in simple-cycle peaking service

- **We'll need cost information for both SCR and Oxidation Catalyst**
- Current NOx performance: assume 120 ppm NOx at 15% O2. (0.44 lb/mmbtu)
- Desired SCR performance of 4 ppm NOx with < 5 ppm ammonia slip
- Current VOC performance 0.024 lb/mmbtu. Desired OC performance 80% control.
- Typical exhaust temperature range 950F to 1080F.
- Maximum Exhaust mass flow rate 2,353,000 lb/hr
- Elevation 1700 ft.

Unit B: A 1991 General Electric PG7111-EA (84.5 MW) operating in simple cycle peaking service

- **Cost for SCR only (not Ox. Catalyst)**
- Current performance with water injection about 42 ppm NOx at 15% O2
- Desired SCR performance of 2 ppm with < 5 ppm ammonia slip
- Exhaust Temperature range 970 – 1010°F
- Maximum Exhaust mass flow Rate. 2,350,000 lb/hr
- Elevation 1700 ft.

Unit C: A late 1970s Westinghouse Model 501B6 (85 MW) combined cycle turbine

- **Cost for Oxidation Catalyst Only (not SCR)**
- Current VOC performance 0.0046 lb/mmbtu. Desired OC performance 2 ppm at 5% O2.
- Exhaust (stack) temperature ~270 - 280°F.
- Exhaust (stack) volumetric flow rate 1,010,000 acfm (685,000 wscfm).
- Assume the HRSG contains sufficient space for the catalyst grid.
- Elevation 1700 ft.

Jelinek, Steve

From:	Vaughn Watson <vwatson@OneCECO.com>
Sent:	Monday, September 12, 2022 12:20 PM
To:	Jelinek, Steve; Jake Moses
Cc:	Royer, Todd
Subject:	[EXTERNAL] RE: [EXT] RE: Peerless P2213323 - Budgetary Proposal for Installation of SCR/CO Systems on Three Turbines

Steve,

Thanks for your patience on this response. I was unfortunately out all last week with Covid.

1. For each of the three options, we need to estimate an annualized cost for period catalyst replacement. Can you tell us:
   a. The expected catalyst life (years)? The guaranteed catalyst performance life is 3 years, that said we typically see catalyst replacement intervals greater than 5-6 years.
   b. The approximate percentage of the total equipment cost for each option that the catalyst represents?

      1. For Unit A: The SCR Catalyst cost for replacement is roughly $900,000. The CO Catalyst cost for replacement is roughly $750,000.
      2. For Unit B: The SCR Catalyst cost for replacement is roughly $900,000.
      3. For Unit C: The CO Catalyst cost for replacement is roughly $750,000.

2. Regarding Option A (the system for the GE 7B CT), we're evaluating economic feasibility on a pollutant-specific basis. Recognizing that you've given us equipment and installation costs for the "total" system (SCR and oxidation catalyst combined)
   a. Are you quoting a single catalyst reactor that would house both catalyst grids?
   b. Can you provide an approximate break out the equipment cost as follows:
      i. SCR catalyst & catalyst support The SCR Catalyst cost for Frame and Catalyst is roughly $1,100,000.
      ii. Oxidation catalyst & catalyst support The SCR Catalyst cost for Frame and Catalyst is roughly $900,000.
      iii. Ammonia storage, handling, distribution and controls, The approximate costs of this is $2,500,000
      iv. Balance of equipment (tempering air fans, expansion joints, catalyst housing, stack, engineering, freight, etc.) The approximate costs of this is $6,500,000

Let us know if you have any further questions.

Vaughn R. Watson | Director, Power Retrofit
CECO Peerless

CECO Environmental
14651 North Dallas Pkwy, Ste. 500 | Dallas, TX 75254
M: 214.668.1014 |**E:** vwatson@onececo.com

CECO Peerless

From: Jelinek, Steve <Steve.Jelinek@aecom.com>
Sent: Friday, September 9, 2022 1:42 PM
To: Vaughn Watson <vwatson@OneCECO.com>; Jake Moses <DMoses@OneCECO.com>
Cc: Royer, Todd <todd.royer@aecom.com>
Subject: RE: [EXT] RE: Peerless P2213323 - Budgetary Proposal for Installation of SCR/CO Systems on Three Turbines

Sorry to hear that, Vaughn. A reply next week will be fine; I just didn't want this to fall through the cracks as the timeline for things on our end is pretty tight.

Thanks!

From: Vaughn Watson <vwatson@OneCECO.com>
Sent: Friday, September 9, 2022 2:38 PM
To: Jelinek, Steve <Steve.Jelinek@aecom.com>; Jake Moses <DMoses@OneCECO.com>
Cc: Royer, Todd <todd.royer@aecom.com>
Subject: [EXTERNAL] Re: [EXT] RE: Peerless P2213323 - Budgetary Proposal for Installation of SCR/CO Systems on Three Turbines

Steve,

My apologies, I've been out all week with Covid. Ill get you a response early next week.

Thanks for your patience.

Vaughn R. Watson | Director, Power Retrofit & Refinery Services

CECO Peerless
CECO Environmental
14651 North Dallas Pkwy, Ste. 500 | Dallas, TX 75254
M: 214.668.1014 |**E:** vwatson@onececo.com

From: Jelinek, Steve <Steve.Jelinek@aecom.com>
Sent: Friday, September 9, 2022 1:30:55 PM
To: Jake Moses <DMoses@OneCECO.com>
Cc: Vaughn Watson <vwatson@OneCECO.com>; Royer, Todd <todd.royer@aecom.com>
Subject: [EXT] RE: Peerless P2213323 - Budgetary Proposal for Installation of SCR/CO Systems on Three Turbines

Hi Jake –

I don't believe I've seen answers to these questions yet; can you give me an idea of when you folks might be able to get back to us on these?

Thanks,
Steve

From: Jelinek, Steve
Sent: Friday, September 2, 2022 10:15 AM
To: Jake Moses <DMoses@OneCECO.com>
Cc: Vaughn Watson <vwatson@OneCECO.com>; Royer, Todd <todd.royer@aecom.com>
Subject: RE: Peerless P2213323 - Budgetary Proposal for Installation of SCR/CO Systems on Three Turbines

Good morning, Jake –

After reviewing your proposal, we had a couple of followup questions.

1. For each of the three options, we need to estimate an annualized cost for period catalyst replacement. Can you tell us:
    a. The expected catalyst life (years)?
    b. The approximate percentage of the total equipment cost for each option that the catalyst represents?
2. Regarding Option A (the system for the GE 7B CT), we're evaluating economic feasibility on a pollutant-specific basis. Recognizing that you've given us equipment and installation costs for the "total" system (SCR and oxidation catalyst combined)
    a. Are you quoting a single catalyst reactor that would house both catalyst grids?
    b. Can you provide an approximate break out the equipment cost as follows:
        i. SCR catalyst & catalyst support
        ii. Oxidation catalyst & catalyst support
        iii. Ammonia storage, handling, distribution and controls, and
        iv. Balance of equipment (tempering air fans, expansion joints, catalyst housing, stack, engineering, freight, etc.)

Thanks very much for these clarifications. Feel free to give me a call if you need any clarification.

Best regards,

Steve Jelinek, PE
Senior Process Engineer

AECOM
250 Apollo Dr.
Chelmsford, MA 01824
(978) 905-2256 (office)

From: Jake Moses <DMoses@OneCECO.com>
Sent: Wednesday, August 31, 2022 10:47 AM
To: Jelinek, Steve <Steve.Jelinek@aecom.com>
Cc: Vaughn Watson <vwatson@OneCECO.com>; Royer, Todd <todd.royer@aecom.com>
Subject: [EXTERNAL] Peerless P2213323 - Budgetary Proposal for Installation of SCR/CO Systems on Three Turbines

Steve,

Peerless is pleased to submit our budgetary proposal for the installation of SCR/CO Systems on the requested units.

Please let us know if you have any questions or concerns.

Best regards,

Jake Moses | Applications Engineer
CECO Peerless
CECO Environmental
14651 North Dallas Pkwy, Ste. 500 | Dallas, TX 75254
M: 469-203-7672 | **E:** dmoses@onececo.com

CECO Peerless

Jelinek, Steve

From:	Spitzer, Sean (NV Energy) <Sean.Spitzer@nvenergy.com>
Sent:	Thursday, September 15, 2022 2:08 PM
To:	Jelinek, Steve; Royer, Todd
Cc:	Heintz, Christopher (NV Energy); Giannantonio, Anthony (NV Energy); Elkins, Sydney (NV Energy)
Subject:	[EXTERNAL] FW: NOx controls at Clark 4

Hi Steve/Todd, take a look at the reply for Clark 4 NOx controls. Let's discuss once you've had a chance to review,
Sean

From: Nell, Michael (NV Energy) <Michael.Nell@nvenergy.com>
Sent: Thursday, September 15, 2022 10:51 AM
To: Spitzer, Sean (NV Energy) <Sean.Spitzer@nvenergy.com>
Subject: NOx controls at Clark 4

Sean,

Below is the only option that is potentially available for Clark 4 according to GE:

Combustor: **7B DLN1+ Low NOx Gas Only, 25 ppmvd Nox @ 15% O2 / 25 ppm CO**

Operation / Emissions							
Fuel	Operation	Diluent	NOx (15% O2) ppmvd	CO ppmvd	UHC / VOC ppmvw (6)	Ambient Temperature Range	Mai
Natural Gas (41040)	Base & Part	dry	25	25	7 / 1.4	-20 to 120 F	No

Pre-requisites / Notes
Mark VIe Controls
Gas Only

Feasibility study $1.5-2.5M (initial requirement) – this has never been implemented before so a study would be required to confirm that its capable of being implemented.

Potential custom development Cost: $2-4M (this is an estimated value, however the SOW/final cost is driven as a result of the feasibility study)
Known needs:

- Requires new 7E/7EA S1N and Support Ring with possible rotor impacts
- Assumes: 1042F Isotherm, Requires Autotune, Combustion Dynamics Monitoring (CDM) => study could turn up option to improve performance but may require generator major upgrade or a swap due to the lack of margin on the presently installed open-ventilated generator.
- Lab testing is required
- Fleet leader inspections will be required

Background:
The model 71B gas turbines were sold (in the early 1970's) with 1840 F firing temperature. The 1840 F firing temperature is substantially colder than the 2020 F firing temperature on production 7EA turbines when DLN was developed (in the early 1990's). Uprating the 71B turbines to a substantially higher firing temperature is not an option without further custom evaluation.
Therefore, NPI development is needed to adapt the 7E/7EA DLN product to the colder firing temperature of the 71B turbines at minimum. The most critical design parameter is that the radial temperature distribution into the nozzles and buckets does not have a hot spot. The second design parameter is dynamics, with the dynamics required to be low enough for a reasonable combustion inspection interval, and for the flame to be evenly distributed and stable enough for CO to be in control.

Upgrade estimated cost could range from $15M -23M

Thanks,
Mike Nell

From: Nell, Michael (NV Energy)
Sent: Tuesday, September 13, 2022 12:41 PM
To: Spitzer, Sean (NV Energy) <Sean.Spitzer@nvenergy.com>
Cc: Jelinek, Steve <steve.jelinek@aecom.com>; Royer, Todd <todd.royer@aecom.com>
Subject: RE: Ballpark quote for NOx controls at Sun Peak

Sean,

I received two options from GE for the Sun Peak units – breakdown below:

Option 1

Model:	**PG7121 (Generator), New Unit Cycle (PIP)**
Combustor:	**7EA.03 DLN1+ Low NOx 9/15/25 ppmvd NOx @ 15% O2 without Late Fuel Staging**

Operation / Emissions					
Fuel	**Operation**	**Diluent**	**NOx (15% O2) ppmvd**	**CO ppmvd**	**UHC / V(ppmvw (**
Natural Gas (GEI41040)	Base & Part	dry	9	25	7 / 1.4
	Base & Part	dry	15	25	7 / 1.4

	Base & Part	dry	25	15	7 / 1.4
	+65F Tfire Peak	dry	25 (for 9 ppm NOx) 40	15	7 / 1.4

Budgetary range ~8M to 10M + Install (per GE, install roughly 1.5 million)

Option 2

Model: **PG7121 (Generator), New Unit Cycle (PIP and AO)**

Combustor: **7EA.03 DLN1+ Ultra Low NOx 4/5 ppmvd NOx @ 15% O2 without Late Fuel Staging**

Operation / Emissions					
Fuel	**Operation**	**Diluent**	**NOx ppmvd (15% O2 Corrected)**	**CO ppmvd (15% O2 Corrected)**	**UHV / V(ppmvw (**
Natural Gas (41040)	Base & part	dry	4	25	7 / 1.4
	Base & part	dry	5	25	7 / 1.4
	Emissions Limited Peak	dry	7.5	25	7 / 1.4

Budgetary range ~10M to 13M + Install (per GE, install roughly 1.5 million)

Pre-requisites / Notes

Mark VIe Controls

Gas Only

GT output will be adversely affected if not off-set with other performance enhancements. This is due to the additional pressure drop through the venturi of the DLN liner. For cases where the unit currently utilizes water or steam injection, the reduction in output will be more significant.

Thanks,

Mike Nell
Turbine Maintenance Manager
Office (702) 402-5764
Mobile (725) 210-2569
Email: michael.nell@nvenergy.com

NVEnergy
a subsidiary of Berkshire Hathaway Energy

From: Spitzer, Sean (NV Energy) <Sean.Spitzer@nvenergy.com>
Sent: Thursday, September 8, 2022 9:46 AM
To: Nell, Michael (NV Energy) <Michael.Nell@nvenergy.com>
Cc: Jelinek, Steve <steve.jelinek@aecom.com>; Royer, Todd <todd.royer@aecom.com>
Subject: RE: Ballpark quote for NOx controls at Sun Peak

Mike, one more addition to this request. We are also performing an analysis on Unit 4 at the Clark Station, which is a GE 7B (7000) from 1973. Can you also ask GE to confirm that there is no DLN retrofit available for this unit due to age of technology? If there is, then the request would be a ballpark estimate for cost as well as expected emission rates with the new burners. Currently they are permitted at 0.44 lb/mmbtu NOx rate and 0.024 lb/mmbtu VOC.

Thanks again in advance,
Sean

From: Spitzer, Sean (NV Energy)
Sent: Thursday, September 1, 2022 2:02 PM
To: Nell, Michael (NV Energy) <Michael.Nell@nvenergy.com>
Cc: Jelinek, Steve <steve.jelinek@aecom.com>; Royer, Todd <todd.royer@aecom.com>
Subject: Ballpark quote for NOx controls at Sun Peak

Hi Mike,
Per our conversation, we are required to perform an emission control technology analysis on the Sun Peak units and are looking to get some ballpark quotes of potential NOX/VOC controls to use in our cost effectiveness calculations. For reference, the Sun Peak units are simple cycle GE PG7111-EA gas fired turbines, 1991 vintage. Their current NOx emission rate is 42 ppmvdc, and 143 lb/hr at that rate. The VOC emission rate is permitted at 1.8 lb/hr.

We're looking for any potential options for NOx reduction such as Dry Low NOx burner retrofit or otherwise. We're interested in how any controls affect the VOC emission rate as well, if that can also be specified in any responses. Our analysis is due at the end of the month so getting a budgetary estimate in the next week or two would be ideal to give us time to incorporate the findings.

I've included our consultants from Aecom, Steve Jelinek and Todd Royer, in the cc of this email as they are the lead authors of our analysis. Please include them in any responses you get. Thanks so much in advance for your help,

Sean Spitzer
Environmental Services Supervisor
NV Energy
6226 W Sahara ave M/S 30
Las Vegas, NV 89146
(702) 513-5010 (cell)

Jelinek, Steve

From: Nell, Michael (NV Energy) <Michael.Nell@nvenergy.com>
Sent: Tuesday, September 13, 2022 3:41 PM
To: Spitzer, Sean (NV Energy)
Cc: Jelinek, Steve; Royer, Todd
Subject: [EXTERNAL] RE: Ballpark quote for NOx controls at Sun Peak

Sean,

I received two options from GE for the Sun Peak units – breakdown below:

Option 1

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	Operation / Emissions				
Fuel	Operation	Diluent	NOx (15% O2) ppmvd	CO ppmvd	UHC / V(ppmvw (
Natural Gas (GEI41040)	Base & Part	dry	9	25	7 / 1.4
	Base & Part	dry	15	25	7 / 1.4
	Base & Part	dry	25	15	7 / 1.4
	+65F Tfire Peak	dry	25 (for 9 ppm NOx) 40	15	7 / 1.4

Budgetary range ~8M to 10M + Install (per GE, install roughly 1.5 million)

Option 2

Model: **PG7121 (Generator), New Unit Cycle (PIP and AO)**

Combustor: **7EA.03 DLN1+ Ultra Low NOx 4/5 ppmvd NOx @ 15% O2 without Late Fuel Staging**

			Operation / Emissions		
Fuel	**Operation**	**Diluent**	**NOx ppmvd (15% O2 Corrected)**	**CO ppmvd (15% O2 Corrected)**	**UHV / V(ppmvw (**
Natural Gas (41040)	Base & part	dry	4	25	7 / 1.4
	Base & part	dry	5	25	7 / 1.4
	Emissions Limited Peak	dry	7.5	25	7 / 1.4

Budgetary range ~10M to 13M + Install (per GE, install roughly 1.5 million)

Pre-requisites / Notes

Mark VIe Controls

Gas Only

GT output will be adversely affected if not off-set with other performance enhancements. This is due to the additional pressure drop through the venturi of the DLN liner. For cases where the unit currently utilizes water or steam injection, the reduction in output will be more significant.

Thanks,

Mike Nell
Turbine Maintenance Manager
Office (702) 402-5764
Mobile (725) 210-2569
Email: michael.nell@nvenergy.com

NVEnergy

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Cc: Jelinek, Steve <steve.jelinek@aecom.com>; Royer, Todd <todd.royer@aecom.com>
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Thanks again in advance,
Sean

From: Spitzer, Sean (NV Energy)
Sent: Thursday, September 1, 2022 2:02 PM
To: Nell, Michael (NV Energy) <Michael.Nell@nvenergy.com>

Cc: Jelinek, Steve <steve.jelinek@aecom.com>; Royer, Todd <todd.royer@aecom.com>
Subject: Ballpark quote for NOx controls at Sun Peak

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We're looking for any potential options for NOx reduction such as Dry Low NOx burner retrofit or otherwise. We're interested in how any controls affect the VOC emission rate as well, if that can also be specified in any responses. Our analysis is due at the end of the month so getting a budgetary estimate in the next week or two would be ideal to give us time to incorporate the findings.

I've included our consultants from Aecom, Steve Jelinek and Todd Royer, in the cc of this email as they are the lead authors of our analysis. Please include them in any responses you get. Thanks so much in advance for your help,

Sean Spitzer
Environmental Services Supervisor
NV Energy
6226 W Sahara ave M/S 30
Las Vegas, NV 89146
(702) 513-5010 (cell)

Attachment 2: Workup of Vendor Cost Information

Workup of Vendor Cost Information

Basis: Quotations received from Peerless Manufacturing Co (PMC), 8/31/2022 and esimated costs from General Electric 9/13/2022 and 9/15/2022

1. SCR equipment cost estimate for Clark Generating Station Unit 4

PMC Quotation dated August 31, 2022, Item I A:
- Complete Simple Cycle SCR & CO/VOC Exhaust System for "Unit A": A 1974 General Electric 7B (7000) Turbine (60 MW) Operating in Simple-Cycle Peaking Service

Budget Price for One (1) SCR/CO/VOC System:	$11,000,000

Equipment cost breakdown (email from PMC 9/12/2022)

SCR catalyst plus SCR catalyst support:	$1,100,000
SCR catalyst cost:	$900,000
Ammonia storage and handling equipment:	$2,500,000
Oxidation catalyst and catalyst support:	$900,000
Oxidation catalyst cost:	$750,000
Other system components:	$6,500,000
SCR catalyst support cost (by difference):	$200,000

Estimated equipment cost for SCR system alone:

SCR catalyst :	$900,000
SCR catalyst support:	$200,000
Ammonia storage and handling equipment:	$2,500,000
Other system components:	$6,500,000
Total SCR system equipment cost:	**$10,100,000**

2. Direct SCR installation cost estimate for Clark Unit 4

PMC Quotation dated August 31, 2022, Item I A:
- Complete Simple Cycle SCR & CO/VOC Exhaust System for "Unit A": A 1974 General Electric 7B (7000) Turbine (60 MW) Operating in Simple-Cycle Peaking Service

Budget Estimate for System Mechanical Installation:	$7,625,000

Estimated direct installation cost for SCR system alone:
(installation cost assumed to be proportional to equipment cost)

Combined system equipment cost estimate:	$11,000,000
Estimated cost for SCR system alone:	$10,100,000
Ratio, estimated SCR system cost/total system cost:	0.9182

Estimated direct installation cost for SCR system:

(0.9182)*(7625000) =	$7,001,275
say:	**$7,000,000**

3. SCR catalyst replacement cost for Clark Unit 4

SCR catalyst cost per PMC email 9/12/2022:	\$900,000
Estimated catalyst life (n):	5 years
Allowable NVE return on capital (i):	7.14%
Capital recovery factor: CRF = $(i*(1/((1+i)^n-1)$	0.1734
Annual catalyst replacement charge:	
(0.1734)*(900000) =	\$156,060 /yr
say:	**\$156,100** /yr

4. Total installed cost for Dry Low NOx combustors for Clark Unit 4

Email from Michael Nell (NV Energy) to Sean Spitzer (NV Energy) September 15, 2022 summarizing information from General Electric about the feasibility and estimated cost of Dry Low NOx Equipment for Clark Unit 4

Budgetary range for total installed cost: \$15 MM to \$23 MM
use midpoint of estimated cost range; say: **\$19,000,000**

5. Oxidation catalyst equipment cost estimate for Clark Unit 4

PMC Quotation dated August 31, 2022, Item I C:
- Combined-Cycle Retrofit CO/VOC Catalyst System for "Unit C": A late 1970s Westinghouse Model 501B6 (85 MW) Combined Cycle Turbine

Budget Price for One (1) Retrofit CO/VOC System: \$2,500,000

Clark Generating Station Unit 4 Output:	60 MW
Vendor Quotation Output Basis:	85 MW

Estimated CO/VOC system equipment cost for CGS Unit 4:
(scaled using "six-tenths" factor; Chemical Engineer's Handbook (fifth edition) equation 25-9: $C_2 = r^{0.6} * C_1$)

C_1 = Equipment cost for Unit 1 (i.e., "Unit C" from PMC Quotation)
= \$2,500,000

r = ratio of capacities; Unit 2/Unit 1 (i.e., 60 MW/85 MW)
= 0.706

C_2 = Equipment cost for Unit 2 (i.e., CGS Unit 4)
= $(0.706)^{0.6}$ * \$2,500,000 = \$2,028,521
say: **\$2,030,000**

6. Direct oxidation catalyst installation cost estimate for Clark Unit 4

PMC Quotation dated August 31, 2022, Item I C:
- Combined-Cycle Retrofit CO/VOC Catalyst System for "Unit C": A late 1970s Westinghouse Model 501B6 (85 MW) Combined Cycle Turbine

Budget Estimate for System Mechanical Installation: $1,500,000

Assume equivalent installation cost for Clark Generating Station Unit 4

$1,500,000

7. Oxidation catalyst replacement cost for Clark Unit 4

Oxidation catalyst cost per PMC email 9/12/2022:	$750,000	
Estimated catalyst life (n):	5	years
Allowable NVE return on capital (i):	7.14%	
Capital recovery factor: CRF = $(i*(1/((1+i)^n-1)$	0.1734	
Annual catalyst replacement charge:		
(0.1734)*(750000) =	$130,050	
say:	**$130,100**	

8. SCR equipment cost estimate for Sun Peak Generating Station Units 3 -5

PMC Quotation dated August 31, 2022, Item I B:
- Complete Simple Cycle SCR Exhaust System for "Unit B": A 1991 General Electric PG-7111-EA (84.5 MW) Operating in Simple Cycle Peaking Service

Budget Price for One (1) SCR System: **$12,500,000**

9. Direct SCR installation cost estimate for Sun Peak Units 3 - 5

PMC Quotation dated August 31, 2022, Item I B:
- Complete Simple Cycle SCR Exhaust System for "Unit B": A 1991 General Electric PG-7111-EA (84.5 MW) Operating in Simple Cycle Peaking Service

Budget Estimate for System Mechanical Installation: **$8,500,000**

10. SCR catalyst replacement cost for Sun Peak Units 3 - 5

Assume equivalent to catalyst replacement cost for Clark Generating Station Unit 4

$156,100 /yr

11. Equipment cost for Dry Low NOx combustors for Sun Peak Units 3 - 5

Email from Michael Nell (NV Energy) to Sean Spitzer (NV Energy) September 13, 2022
summarizing General Electric Dry Low NOx Equipment Estimates for the Sun Peak Units
Option 1 - Model: PG7121
Combustor: 7EA.03 DLN1+Low NOx 9/15/25 ppmvd NOx @15% O2 without Late Fuel

Budgetary range: $8 MM to $10 MM
use midpoint of estimated cost range; say: **$9,000,000**

12. Direct Dry Low NOx combustors installation cost estimate for Sun Peak Units 3 - 5

Email from Michael Nell (NV Energy) to Sean Spitzer (NV Energy) September 13, 2022
summarizing General Electric Dry Low NOx Equipment Estimates for the Sun Peak Units
Option 1 - Model: PG7121
Combustor: 7EA.03 DLN1+Low NOx 9/15/25 ppmvd NOx @15% O2 without Late Fuel

Installation (per GE, install roughly $1.5 MM) **$1,500,000**

Case-by-Case Major Source RACT Analyses for Clark County, NV: Appendices

Appendix7b

NV Energy Supporting Documentation (03/30/2023)

NVEnergy

March 30, 2023

Mr. Ted Lendis
Permitting Manager
Clark County Department of Environmental and Sustainability, Division of Air Quality
4701 W. Russel Road, Suite 200
Las Vegas, NV 89118

Subject: Response to Additional RACT Analysis Questions – NV Energy Clark and Sun Peak Generating Stations

Dear Mr. Lendis:

NV Energy (NVE) is pleased to provide you with the following information to augment the Reasonably Available Control Technology (RACT) Analysis that was submitted to you on October 3, 2022 for our Clark and Sun Peak Generating Stations. This information is being provided in response to the questions raised by your consultant (RTP Environmental Associates) in their two email transmittals to us on February 6, 2023 and our subsequent conference call with them on February 21. The information that RTP has requested, along with our responses to those information requests, is presented on the following pages.

NV Energy anticipates further communication from DAQ on this topic in the near future. If you require additional information or have any questions, please contact Chris Heintz at (702) 402-2048 or Christopher.Heintz@nvenergy.com.

I certify that, based on the information and belief formed after reasonable inquiry, the statements and information in this document are true, accurate, and complete.

Sincerely,

Jason Hammons
Vice President, Generation
NV Energy
Responsible Official

Cc: Rob Barton – RTP Environmental Associates

Q1: What is the source of the current Clark Generating Station Unit 4 VOC limit (0.024 lb/MMBtu)? Does this represent design specifications?

A1: As was explained during our conference call on February 21, the baseline VOC emission rate for Clark Generating Station Unit 4 of 0.024 lb VOC/MMBtu is not an emission limit or design specification. Rather, this figure is back calculated based on the originally established potential-to-emit emission rate for the unit. This unit was installed in 1973 and none of the unit's original design specifications are available.

Q2: What is the source of the current Clark Generating Station Unit 4 NOx performance (120 ppm)? Does this represent design specifications?

A2: As in the response to the previous question, none of Unit 4's original design specifications are available. 120 ppm NOx @15% O2 (0.44 lb/MMBtu) is the emission rate that has historically been used to quantify actual NOx emissions from this unit.

Q3: The 'Design Criteria' section of the CECO cost estimate shows 'Desired OC performance 80% control' for Unit A (Clark Generating Station Unit 4), whereas the OC performance for Unit C (Clark Generating Station Units 5 – 8) is 2 ppm. What is the reason for the lower control efficiency for Unit 4? Temperature?

A3: The rationale for requesting different performance specifications for the oxidation catalyst system quotations for Clark Generating Station Units 4 and 5 – 8 is the different VOC concentrations in the turbine exhausts for these units. For Unit 4, the current VOC exhaust concentration based on an emission rate of 0.024 lb/MMBtu is approximately 85 ppm @ 15% O_2 on an as-propane basis. For Units 5 - 8, the VOC exhaust concentration is much lower; based on an emission rate of 0.0046 lb/MMBtu it is approximately 16 ppm @ 15% O_2 on an as-propane basis.

Regardless of whether the oxidation catalyst system quoted for Clark Unit 4 can achieve the marginally higher VOC control performance specified for Units 5 - 8, an oxidation catalyst system is unrepresentative of RACT for Unit 4 based on unreasonable cost effectiveness given this unit's historically low utilization rate and the low rate that it is projected to be utilized in the future. As presented in Table 5-1 of our original RACT assessment, an oxidation catalyst system that achieves 80% reduction in VOC emissions from Unit 4 would reduce annual VOC emissions from the unit by 1.64 tons/yr and have a cost effectiveness of over $376,000 per ton removed. If, however, the system that was quoted could achieve the VOC control performance specified for Units 5 - 8 (approximately 87.5%), it would reduce annual VOC emissions from Unit 4 by an only very slightly greater amount (1.79 tons/yr) and have a cost effectiveness of $344,900 per ton removed.

Q4: The 'Design Criteria' section of the CECO cost estimate for Unit C (CCUs) shows VOC performance of '2 ppm @ 5% O_2'. Is this correct or is the O_2 correction 15%?

A4: The correct turbine exhaust oxygen concentration for the CECO cost estimate for Unit C should be 15% O_2, not 5% O_2.

Q5: The 'Design Criteria' section of the CECO cost estimate for Unit A (Clark Generating Station Unit 4) shows selective catalytic reduction (SCR) system performance of 4 ppm NOx with < 5 ppm slip, whereas SCR performance for Unit B (SPGS) is 2 ppm NOx with < 5 ppm slip. Is 2 ppm achievable for Clark Generating Station Unit 4? If not, what is the technical basis for not lowering the target to 2 ppm?

A5: The rationale for the higher outlet concentration specification for the SCR system for Clark Generating Station Unit 4 compared to the system for Sun Peak Generating Station Units 3 - 5 was the higher inlet NOx concentration (120 ppm vs 42 ppm). In both quotations, the basis for CECO's quotation was a single stage of SCR catalyst, capable of approximately 95% NOx conversion. Achieving an outlet NOx emission rate of 2 ppm for Clark Unit 4 would require approximately 98% NOx conversion, which would not be achievable with the catalyst system design quoted. CECO subsequently explained that a system containing approximately twice as much catalyst as originally quoted would be required to achieve 98% conversion. In addition to the cost considerations, an SCR catalyst system imposes backpressure on a turbine exhaust system that has the effect of reducing the system's output capacity. CECO stated that a single stage of SCR catalyst typically imposes an exhaust system backpressure of between 3 and 4 inches of water, which can reduce the output of a simple cycle turbine by approximately 2%. Consequently, providing sufficient catalyst to achieve an outlet concentration of 2 ppm on Unit 4 may reduce the output of this unit by approximately 4%.

Q6: Is it technically feasible to add water injection for Clark Generating Station Units 5-8 or is that limited by combustor design?

A6: NV Energy was required by the terms of a Consent Decree issued on August 9, 2007 by the United States Environmental Protection Agency to replace the original combustors on Clark Generating Station Units 5 – 8 with Ultra Low NOx Burner (ULNB) combustors. These UNLB combustors employ lean premixed combustion principles that enable the units to comply with an emission limit of 5 ppm @ 15% O_2. The combustors on Units 5 – 8 are designed to operate without the use of water or steam injection, thus further reduction of NOx emissions using water injection is not a technically feasible alternative for these units.

Q7: Is it technically feasible to increase ammonia injection on Clark Generating Station Units 11-28 to achieve 2 ppmvd? If so, what is the expected slip?

A7: Units 11 – 28 at Clark Generating Station are equipped with SCR systems designed to achieve an emission limit from each unit of 5 ppm @ 15% O2. The SCR system supplier stated that these systems are designed with sufficient catalyst to achieve compliance with the NOx emission limit while minimizing emissions of unreacted ammonia. The supplier noted that it is not feasible to simply raise the rate of ammonia injection to achieve a lower NOx emission target with the same amount of catalyst, which is an operational measure that the supplier referred to as "spray and pray." The supplier stated that adding an excess of ammonia beyond the stoichiometric amount needed to achieve the design NOx emissions rate would have the effect of flooding the catalyst with ammonia, thereby reducing its NOx reduction effectiveness. The supplier explained that injecting too much reagent into the catalyst causes the active catalyst sites to become blinded with ammonia, thereby precluding their ability to be available to allow the NOx reduction reactions to occur.

Q8: Oil-firing capability – The RACT analysis indicates that #2 oil was not fired in the Sun Peak Generating Station units during the baseline period and is not expected to be used in the future. Is NV Energy planning to remove oil combustion capability from the permit?

A8: Although distillate oil has not been utilized in the Sun Peak Generating Station combustion turbines for quite some time, NV Energy has no plans to remove oil-firing capability from the facility's air permit. It is prudent for NV Energy to preserve the capability to utilize oil in these units in terms of maintaining the Station's reliability to provide power to the grid should the natural gas supply to the facility be curtailed at some point in the future.

Q9: Increased water injection – In your January 30, 2023 response to RTP's request for supplemental RACT information for the Sun Peak Generating Station, GE indicated that the water injection rate needed to meet a potential limit of 25 ppm "could be expected to cause the Sun Peak Generating Station units to emit CO at a much higher level than they do currently". Can you confirm with GE what the expected CO emissions would be if NOx were reduced with increased water injection from current 42 ppm to 25 ppm and whether it would cause the units to exceed the CO limit of 10 ppm? Do you have design specs for the system (uncontrolled/controlled NOx, WFR, efficiency, etc.)? This option will likely receive increased scrutiny because of relatively low cost. The more supporting information you can provide regarding technical feasibility the better.

A9: As we explained in our response to RTP's first set of questions, GE stated that it is not technically feasible to achieve a NOx emission level of 25 ppm @ 15% O_2 using water injection with the combustors that are currently installed on Sun Peak Units 3 – 5. To achieve this emissions level with water injection, the units would need to be retrofitted with new combustors. GE estimated that the new combustors would have an equipment cost of between $4 and $6 million per unit, plus another $2 million per unit in combustor process control system and software upgrades. Considering that these units are limited to operate no more than 12 hours per day and typically only operate for less than 500 hours per year, the capital expenditure needed to achieve this marginal reduction in NOx emissions is not justifiable. Moreover, GE estimates that that the uncontrolled CO emission rate at the water injection rate needed to achieve a NOx emission rate of 25 ppmvd @15% O_2 would be 150 ppmvd @ 15% O_2, which is considerably higher than the current CO emission limit for these units (10 ppmvd @15% O_2).

Appendix 8

Saguaro RACT Analysis

DES DEPARTMENT OF ENVIRONMENT AND SUSTAINABILITY air quality · desert conservation PROGRAM · sustainability 4701 W. Russell Road 2nd Floor Las Vegas, NV 89118-2231 Phone: (702) 455-5942 Fax: (702) 383-9994 Marci Henson, Director	**For DAQ Use Only**

Certification Statement

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the attached document(s) are true, accurate, and complete. This certification applies to the following stationary source:

Source ID:	Source Name:
00393	SAGUARO POWER COMPANY

Certification

Name of Responsible Official:	Responsible Official's Title:	Company/Organization:
ROB MAY	PLANT MANAGER	SAGUARO POWER COMPANY

Responsible Official's Signature	Certification Date
[signature]	10-3-22

Reasonably Available Control Technology Analysis

Clark County Department of Environment and Sustainability
Division of Air Quality

Saguaro Power Company
435 Fourth Street
Henderson, NV 89015

Source ID 393

October 03, 2022

Prepared by:

BROADBENT
8 W. Pacific Avenue
Henderson, Nevada 89015

Project No. 05-01-239

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1. Background

Clean Air Act (CAA) Section 181(a) includes a classification system for areas designated nonattainment for the ozone National Ambient Air Quality Standard (NAAQS). This classification system is based on the severity of the air quality as determined by the area's ozone design value and includes five categories: marginal, moderate, serious, severe and extreme. In 2018, the U.S. Environmental Protection Agency (EPA) designated hydrographic area (HA) 212 in Clark County, Nevada as nonattainment for the 2015 ozone NAAQS and assigned a classification of marginal to the area. The area was required to reach attainment of the 2015 ozone NAAQS by August 3, 2021. In July 2022, EPA determined that HA 212 failed to meet this deadline and, in addition, proposed to reclassify HA 212's attainment status classification to moderate based on its own ozone design value.

In response to this proposed EPA action, the Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ) is required to establish emissions control requirements in its State Implementation Plan (SIP) that include Reasonably Available Control Technology (RACT) requirements. RACT is defined by the EPA as "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." A RACT analysis should, therefore, take into account the technological and economic impacts of controls. For example, if a certain type of emission control or emission limitation is determined to be too costly compared to the amount of emission reduction it achieves, that control might not be considered RACT. Also, as economic factors may vary by region, a control technology or emission limitation designated as meeting RACT in one location does not necessarily define RACT for another location.

The CAA requires moderate ozone nonattainment areas to implement RACT for sources of ozone forming emissions. Ozone forming emissions include volatile organic compounds (VOC) and nitrogen oxides (NO_x). More specifically, the DAQ is required to adopt RACT level controls for sources subject to an EPA Control Techniques Guidelines (CTG) document (addressing sources of VOC) and for any other major sources of VOC and NO_x. The major source threshold for an area classified as moderate is 100 tons per year and is applied to a stationary source's potential to emit (PTE) to determine whether RACT requirements need to be evaluated for any particular stationary source. DAQ has determined that it will use a stationary source's PTE as applied in the major New Source Review program and Title V (Part 70) operating permits program to identify the major stationary sources subject to RACT. In addition, DAQ has requested that each major stationary source located in HA 212 make a determination as to whether it is to be considered a major stationary source subject to a RACT evaluation and, if so, perform the evaluation and submit the evaluation to DAQ for review and inclusion in the SIP revisions required as a result of the EPA's attainment area status reclassification action.

This report summarizes the RACT analysis performed by the Saguaro Power Company (Saguaro) and contains its source specific recommendations for RACT.

2. RACT Applicability

Saguaro's Henderson facility is an electricity and steam generating operation located in HA 212. The facility operates two 35-MW natural gas combined cycle combustion turbine generators (CTGs); two diesel starter engines; two auxiliary natural gas-fired boilers; a three-celled cooling tower; and four 25 MMBtu/hr supplemental-firing duct burners. In addition, the facility operates a 29.1 MW extraction/condensing steam turbine generator system and an ammonia storage and injection system as insignificant activities. It currently operates as a Part 70 major stationary source according to the conditions contained in the Part 70 Operating Permit Source ID 393 issued by DAQ. A copy of the current permit is included in Appendix A. Since the Part 70 major source classification is the same as the moderate attainment area major source classification, RACT is required only if the permitted PTE for either VOC or NO_x exceeds the Part 70 major source threshold. According to Table 1 contained in the facility's current Part 70 operating permit, the PTE for NO_x emissions is 163.77 tons per year and the PTE for VOC emissions is 13.36 tons per year therefore, only NO_x emissions exceed both the Part 70 major source and moderate area major source thresholds. This analysis is limited to emissions of NO_x.

3. Emission Units Subject to RACT

In their request for individual stationary source RACT analyses, DAQ further delineated the applicability requirement to a so-called Phase 1 level that includes only those individual emission units at the major stationary source with a PTE that exceeds 5 tons per year. Table 1 lists the emission units at the Saguaro facility that exceed this threshold.

Table 1 – Emission Units Subject to RACT

<table>
<tr><th>Emission Unit ID[1]</th><th>Description</th><th>Maximum Rating</th><th>Manufacturer</th><th>Model</th><th>Fuel Type</th><th>NO_x PTE[2] (tons per year)</th></tr>
<tr><td>A01</td><td>Combustion Turbine Generator #1 with a fired HRSG[3]</td><td>35 MW</td><td>General Electric</td><td>PG6541B</td><td>Natural gas, diesel</td><td rowspan="3">69.24[4]</td></tr>
<tr><td>F05</td><td>Supplemental Duct Burner, Skid #1</td><td>25 MMBtu/hr</td><td>John Zink</td><td>LDR-11-LE</td><td>Natural gas</td></tr>
<tr><td>F05a</td><td>Supplemental Duct Burner, Skid #1</td><td>25 MMBtu/hr</td><td>John Zink</td><td>LDR-11-LE</td><td>Natural gas</td></tr>
<tr><td>A02</td><td>Combustion Turbine Generator #2 with a fired HRSG[3]</td><td>35 MW</td><td>General Electric</td><td>PG6541B</td><td>Natural gas, diesel</td><td rowspan="3">69.24[4]</td></tr>
<tr><td>F06</td><td>Supplemental Duct Burner, Skid #2</td><td>25 MMBtu/hr</td><td>John Zink</td><td>LDR-11-LE</td><td>Natural gas</td></tr>
<tr><td>F06a</td><td>Supplemental Duct Burner, Skid #2</td><td>25 MMBtu/hr</td><td>John Zink</td><td>LDR-11-LE</td><td>Natural gas</td></tr>
<tr><td>A05</td><td>Auxiliary Boiler #1</td><td>218 MMBtu/hr</td><td>Indeck/ Volcano</td><td>0-7-2000</td><td>Natural gas</td><td>13.94[5]</td></tr>
<tr><td>A06</td><td>Auxiliary Boiler #2</td><td>86 MMBtu/hr</td><td>Nebraska</td><td>NOS 2A/S-55</td><td>Natural gas</td><td>9.33[6]</td></tr>
</table>

Notes: [1] Emission Unit ID from Part 70 Operating Permit Table II-A-1: List of Emission Units.
[2] PTE from Part 70 Operating Permit Table II-D-1: Emission Unit PTE, Including Startup and Shutdowns (tons per year).
[3] Emission units F05, F05a, F06 and F06a make up the fired HRSG.
[4] Annual emissions based on worst-case scenario of 480 hours/consecutive 12-months of diesel. combustion and 8,280 hours/consecutive 12-months of natural gas combustion.

[5] Emissions based on 8,760 hours per year operation.
[6] Emissions based on 6,000 hours per year operation.

In addition, each emission unit listed in Table 1 has emission limits in pounds per hour and exhaust gas NO_x concentrations in ppm as well as limitations on the amount of fuel burned annually. These additional limitations are summarized in Tables 2 and 3.

Table 2 – Emission Unit Emissions Limitations

Emission Unit ID	Fuel Type	NO_x Emission Rate (lb/hr)	NO_x Concentration (ppm)
A01, F05, F05a	Natural gas	15.20	10 @ 15% O_2
	Diesel	26.30	17 @ 15% O_2
A02, F06, F06a	Natural gas	15.20	10 @ 15% O_2
	Diesel	26.30	17@ 15% O_2
A05	Natural gas	3.18	12 @ 3% O_2
A06	Natural gas	3.11	30 @ 3% O_2

Table 3 - Emission Unit Throughput Limitations

Emission Unit ID	Fuel Type	Fuel Use	
		Hourly	Annual
A01	Natural gas	447 MMBtu	3,915,720 MMBtu
	Diesel	3,035 gal	-
A02	Natural gas	447 MMBtu	3,915,720 MMBtu
	Diesel	3,035 gal	-
F05, F05a	Natural gas	25 MMBtu	219,000 MMBtu
F06, F06a	Natural gas	25 MMBtu	219,000 MMBtu
A05	Natural gas	218 MMBtu	1,909,680 MMBtu
A06	Natural gas	86 MMBtu	510,000 MMBtu

Actual emissions of NO_x for the entire source and each emission unit for calendar years 2019-2021 are summarized in Table 4.

Table 4 - Actual NO_x Emissions 2019-2021

Emission Unit ID	Actual NO_x Emissions[1] (tons)			Maximum Annual 2019-2021 (tons)	NO_x PTE (tons/year)	Maximum Annual/ PTE
	2019	2020	2021			
Entire Source	107.54	109.64	106.79	109.64	163.77	66.9%
A01/F05/F05a	54.45	54.35	50.70	54.45	69.24	78.6%
A02/F06/F06a	52.22	54.03	55.17	55.17	69.24	79.7%
A05	0.20	0.40	0.12	0.40	13.94	2.9%
A06	0.56	0.72	0.63	0.72	9.33	7.7%

Notes: [1] Entire source actual emissions based on 2019, 2020 and 2021 Emissions Inventories. Individual emission unit actual emissions for the EUs A01, A02 and A05 are based on actual data from continuous emissions monitors and maximum hourly emission rates and actual hours of operation for periods the continuous emissions monitors were not functioning. Emissions for EU A06 are based on maximum hourly emission rates and actual hours of operation.

As shown in Table 4, maximum actual emissions for the entire source are 66.9% of the entire sources' PTE. Individual emission units' maximum actual emissions are approximately 80% of PTE for the turbines and between 3% and 8% for the boilers.

Actual hours of operation for each emission unit for calendar years 2019-2021 are summarized in Table 5.

Table 5 - Actual Hours of Operation 2019-2021

Emission Unit ID	Actual Operation (hours)		
	2019	2020	2021
A01/F05/F05a	8387	8309	8041
A02/F06/F06a	8409	8341	8402
A05	18	326	33
A06	363	461	405

During these years, the turbines operated consistently year-round. The Volcano boiler (EU: A05) operated for tunings and Relative Accuracy Test Audits (RATAs). The Nationwide/Nebraska boiler operated to supply steam to Ocean Spray and for tunings. Future operating schedules of the equipment are uncertain at this time, however, it is not anticipated that there would be significant increases in operation of any emission unit.

4. RACT Analysis

The RACT analysis consists of various steps:

- Identification of existing equipment and baseline emissions
- Identification of available control options
- Elimination of technically infeasible control options

- Determination of the cost effectiveness of control options
- Evaluation of the benefits and disadvantages (environmental, energy and economic) associated with the technically feasible control options
- Identification of RACT control technology including emission limitations, monitoring, testing, recordkeeping and reporting requirements

RACT emissions limitations can take various forms depending on the type of source and as long as the emissions limitations achieve the required emissions reductions and are legally and practically enforceable through appropriate monitoring, recordkeeping and reporting requirements. In addition, RACT is a continuous emissions reduction requirement and must apply over the range of operations [steady-state, startup, shutdown, and malfunctions (SSM)]; however RACT can include alternative emissions limitations or work practices for SSM.

For uniformity of comparison, DAQ has requested that major sources use a 6% interest rate to compute costs. This rate was used in all cost analyses contained in this report.

Regarding the base case for emissions, DAQ has stated that, if a major source's actual emissions over three consecutive, representative years are less than 70% of the major source's PTE, then the major source can elect to use actual emissions for the base case. Since this is the case for Saguaro, the maximum actual annual emissions will be used for each emission unit evaluated for RACT in this report.

A detailed RACT analysis for each emission unit subject to RACT review identified above is included in Appendices B, C and D.

5. Results

Each RACT determination is summarized in Section 3.0 of Appendices B, C, and D.

Appendix A

Part 70 Operating Permit

DES
DEPARTMENT OF ENVIRONMENT AND SUSTAINABILITY
air quality · desert conservation program · sustainability

4701 W. Russell Rd Suite 200
Las Vegas, NV 89118-2231
Phone (702) 455-5942
Fax (702) 383-9994

PART 70 OPERATING PERMIT

SOURCE ID: 393

Saguaro Power Company
435 Fourth Street
Henderson, NV 89015

ISSUED ON: December 8, 2020 **EXPIRES ON: December 7, 2025**

REVISION ON: November 17, 2021

Current action: Reopening for Cause

Issued to:
Saguaro Power Company
PO Box 90849
Henderson, Nevada 89009

Responsible Official:
Rob May
Site Manager
Phone: (702) 558-1131 Fax: (702) 564-2753
Email: rob.may@camsops.com

NATURE OF BUSINESS:
SIC code 4931, "Electric and other Services Combined"
NAICS code 221112, "Fossil Fuel Electric Power Generation"

Issued by the Clark County Department of Environment and Sustainability, Division of Air Quality in accordance with Section 12.5 of the Clark County Air Quality Regulations.

Theodore A. Lendis, Permitting Manager

EXECUTIVE SUMMARY

Saguaro Power Company (Saguaro) is an electricity and steam generating operation located at 435 Fourth Street, Henderson, Nevada 89015, which is in Hydrographic Area 212 (the Las Vegas Valley). Hydrographic Area 212 is designated marginal nonattainment for the 2015 ozone National Ambient Air Quality Standards (NAAQS) and attainment for the remaining regulated air pollutants. All generating and support processes at the site are grouped under SIC code 4931, "Electric and Other Services," and NAICS code 221112, "Fossil Fuel Electric Power Generation."

Saguaro is a categorical stationary source, as defined by AQR 12.2.2(j)(22). The source has a combined total fossil-fuel boiler rating of more than 250 MMBtu/hr. Saguaro operates under the Part 70 Operating Permit (OP) program and is a major stationary source for NO_x, a minor source for PM_{10}, $PM_{2.5}$, CO, SO_2, VOCs, and HAPs, and a source of greenhouse gas (GHG) emissions. Saguaro operates two 35-MW natural gas combined cycle combustion turbine generators (CTGs); two diesel starter engines; two auxiliary natural gas-fired boilers; a three-celled cooling tower; and four 25 MMBtu/hr supplemental-firing duct burners. In addition, Saguaro Power Company operates a 29.1 MW extraction/condensing steam turbine generator system and an ammonia storage and injection system as insignificant activities.

This Title V OP is issued based on a renewal application submitted on January 31, 2019. Table 1 summarizes the potential to emit (PTE) for each regulated air pollutant.

Table 1: Source-wide PTE (tons per year)

Pollutant	PM_{10}	$PM_{2.5}$	NO_X	CO	SO2	VOC	HAP	GHG
PTE	38.75	38.03	163.77	90.13	13.36	13.36	9.04	551,984
Major Stationary Source Thresholds (Categorical)	100	100	100	100	100	100	100	

[1]Expressed as metric tons of CO_2e.

Pursuant to AQR 12.5, all terms and conditions in this permit and the attachment are federally enforceable unless explicitly denoted otherwise.

DAQ will continue to require sources to estimate their GHG PTEs in terms of each individual pollutant (CO_2, CH_4, N_2O, SF_6 etc.), and the TSD includes these PTEs for informational purposes.

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COMMON ACRONYMS AND ABBREVIATIONS

(These terms may be seen in the permit)

Term	Definition
APP	application
AQR	Clark County Air Quality Regulations
ATC	authority to construct
CAAA	Clean Air Act, as amended, or Clean Air Act Amendments
CEMS	continuous emissions monitoring system
CFC	chlorofluorocarbon
CFR	United States Code of Federal Regulations
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
DAQ	Division of Air Quality
dscf	dry standard cubic feet
DOM	date of manufacturer
EPA	United States Environmental Protection Agency
EU	emission unit
GHG	greenhouse gases
HAP	hazardous air pollutant
HCFC	hydrochlorofluorocarbon
HHV	high heating value
hp	horse Power
HRSG	heat recovery steam generator
MMBtu	millions of British thermal units
MW	megawatt
N_2O	nitrous oxide
NAICS	North American Industry Classification System
NESHAP	National Emission Standard for Hazardous Air Pollutants
NO_X	nitrogen oxides
NRS	Nevada Revised Statutes
NSPS	New Source Performance Standards
O_2	oxygen
OP	operating permit
$PM_{2.5}$	particulate matter less than 2.5 microns
PM_{10}	particulate matter less than 10 microns
ppmvd	parts per million, volumetric dry
psia	pounds per square inch absolute
PSD	prevention of significant deterioration
PTE	potential to emit
QA/QC	quality assurance/quality control
QAP	quality assurance plan
RATA	relative accuracy test audit
RMP	risk management plan
scf	standard cubic feet
SCR	selective catalytic reduction

Term	**Definition**
SF_6	sulfur hexafluoride
SIC	Standard Industrial Classification
SIP	state implementation plan
SO_2	sulfur dioxide
TDS	total dissolved solid
TSD	technical support document
U.S.C.	United States Code
VOC	volatile organic compound

I. GENERAL CONDITIONS

A. GENERAL REQUIREMENTS

1. The permittee shall comply with all conditions of the Part 70 OP. Any permit noncompliance may constitute a violation of the Clark County Air Quality Regulations (AQRs), Nevada law, and the Clean Air Act, and is grounds for enforcement action; for permit termination, revocation and reissuance, or revision; or for denial of a renewal application. *[AQR 12.5.2.6(g)(1)]*

2. If any term or condition of this permit becomes invalid as a result of a challenge to a portion of this permit, the other terms and conditions of this permit shall be unaffected and remain valid. *[AQR 12.5.2.6(f)]*

3. The permittee shall pay all permit fees pursuant to AQR 18. *[AQR 12.5.2.6(h)]*

4. This permit does not convey property rights of any sort, or any exclusive privilege. *[AQR 12.5.2.6(g)(4)]*

5. The permittee agrees to allow inspection of the premises to which this permit relates by any authorized representative of the Control Officer at any time during the permittee's hours of operation without prior notice. The permittee shall not obstruct, hamper, or interfere with any such inspection. *[AQR 4.1; AQR 5.1.1; AQR 12.5.2.8(b)]*

6. The permittee shall allow the Control Officer, upon presentation of credentials, to: *[AQR 4.1 & AQR 12.5.2.8(b)]*

   a. Access and copy any records that must be kept under the conditions of the permit;

   b. Inspect any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit;

   c. Sample or monitor substances or parameters for the purpose of assuring compliance with the permit or applicable requirements; and

   d. Document alleged violations using such devices as cameras or video equipment.

7. Any permittee who fails to submit relevant facts, or who has submitted incorrect information in a permit application, shall, upon becoming aware of such failure or incorrect submittal, promptly submit supplementary facts or corrected information. The permittee shall also provide any additional information necessary to address any requirements that become applicable to the source after it filed a complete application but before the release of a draft permit. A responsible official shall certify the additional information consistent with the requirements of AQR 12.5.2.4. *[AQR 12.5.2.2]*

8. Anyone issued a permit under AQR 12.5 shall post it in a location where it is clearly visible and accessible to facility employees and DAQ representatives. *[AQR 12.5.2.6(m)]*

B. MODIFICATION, REVISION, AND RENEWAL REQUIREMENTS

1. No person shall begin actual construction of a new Part 70 source, or modify or reconstruct an existing Part 70 source that falls within the preconstruction review applicability criteria, without first obtaining an Authority to Construct (ATC) from the Control Officer. *[AQR 12.4.1.1(a)]*

2. The permit may be revised, revoked, reopened and reissued, or terminated for cause by the Control Officer. The filing of a request by the permittee for a permit revision, revocation, reissuance, or termination, or of a notification of planned changes or anticipated noncompliance, does not stay any permit condition. *[AQR 12.5.2.6(g)(3)]*

3. A permit, permit revision, or renewal may be approved only if all of the following conditions have been met: *[AQR 12.5.2.10(a)]*

    a. The permittee has submitted to the Control Officer a complete application for a permit, permit revision, or permit renewal (except a complete application need not be received before a Part 70 general permit is issued pursuant to AQR 12.5.2.20); and

    b. The conditions of the permit provide for compliance with all applicable requirements and the requirements of AQR 12.5.

4. The permittee shall not build, erect, install, or use any article, machine, equipment, or other contrivance, the use of which, without resulting in a reduction in the total release of air contaminants to the atmosphere, reduces or conceals an emission that would otherwise constitute a violation of an applicable requirement. *[AQR 80.1 and 40 CFR Part 60.12]*

5. No permit revisions shall be required under any approved economic incentives, marketable permits, emissions trading, and other similar programs or processes for changes that are provided for in the permit. *[AQR 12.5.2.6(i)]*

6. Permit expiration terminates the permittee's right to operate unless a timely and complete renewal application has been submitted. *[AQR 12.5.2.11(b)]*

7. For purposes of permit renewal, a timely application is a complete application that is submitted at least six months, but not more than 18 months, prior to the date of permit expiration. If a source submits a timely application under this provision, it may continue operating under its current Part 70 OP until final action is taken on its application for a renewed Part 70 OP. *[AQR 12.5.2.1(a)(2)]*

C. REPORTING, NOTIFICATIONS, AND INFORMATION REQUIREMENTS

1. The permittee shall submit all compliance certifications to the U.S. Environmental Protection Agency (EPA) and to the Control Officer. *[AQR 12.5.2.8(e)(4)]*

2. Any application form, report, or compliance certification submitted to the Control Officer pursuant to the permit or the AQRs, shall contain a certification by a responsible official, with an original signature, of truth, accuracy, and completeness. This certification, and any other required under AQR 12.5, shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. *[AQR 12.5.2.6(l)]*

3. The permittee shall furnish to the Control Officer, in writing and within a reasonable time, any information that the Control Officer may request to determine whether cause exists for revising, revoking and reissuing, or terminating the permit, or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Control Officer copies of records that the permit requires keeping. The permittee may furnish records deemed confidential directly to the Administrator, along with a claim of confidentiality. *[AQR 12.5.2.6(g)(5)]*

4. Upon request of the Control Officer, the permittee shall provide any information or analyses that will disclose the nature, extent, quantity, or degree of air contaminants that are or may be discharged by the source, and the type or nature of control equipment in use. The Control Officer may require such disclosures be certified by a professional engineer registered in the state. In addition to this report, the Control Officer may designate an authorized agent to make an independent study and report on the nature, extent, quantity, or degree of any air contaminants that are or may be discharged from the source. An agent so designated may examine any article, machine, equipment, or other contrivance necessary to make the inspection and report. *[AQR 4.1]*

5. The permittee shall submit annual emissions inventory reports based on the following: *[AQR 18.6.1]*

   a. The annual emissions inventory must be submitted to DAQ by March 31 of each calendar year (if March 31 falls on a Saturday or Sunday, or on a Nevada or federal holiday, the submittal shall be due on the next regularly scheduled business day);

   b. The calculated actual annual emissions from each emission unit shall be reported even if there was no activity, along with the total calculated actual annual emissions for the source based on the emissions calculation methodology used to establish the potential to emit (PTE) in the permit or an equivalent method approved by the Control Officer prior to submittal; and

   c. As the first page of text, a signed certification containing the sentence: "I certify that, based on information and belief formed after reasonable inquiry, the statements contained in this document are true, accurate, and complete." This statement shall be signed and dated by a responsible official of the company (a sample form is available from DAQ).

6. Stationary sources that emit 25 tons or more of nitrogen oxide (NOx) and/or 25 tons or more of volatile organic compounds (VOCs) during a calendar year from emission units, insignificant activities, and exempt activities shall submit an annual emissions statement for both pollutants. This statement must include actual annual NOx and VOC emissions from all activities, including emission units, insignificant activities, and exempt activities. Emissions statements are separate from, and additional to, the calculated annual emissions reported each year for all regulated air pollutants (i.e., the emissions inventory report). *[AQR 12.9.1]*

D. COMPLIANCE REQUIREMENTS

1. The permittee shall not use as a defense in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. *[AQR 12.5.2.6(g)(2)]*

2. Any person who violates any provision of the AQRs, including, but not limited to, any application requirement; any permit condition; any fee or filing requirement; any duty to allow or carry out inspection, entry, or monitoring activities; or any requirements from DAQ is guilty of a civil offense and shall pay a civil penalty levied by the Air Pollution Control Hearing Board and/or the Hearing Officer of not more than $10,000. Each day of violation constitutes a separate offense. *[AQR 9.1; NRS 445B.640]*

3. Any person aggrieved by an order issued pursuant to AQR 9.1 is entitled to review, as provided in Chapter 233B of the NRS. *[AQR 9.12]*

4. The permittee shall comply with the requirements of Title 40, Part 61 of the Code of Federal Regulations (40 CFR Part 61), Subpart M—the National Emission Standard for Asbestos—for all demolition and renovation projects. *[AQR 13.1(b)(8)]*

5. The permittee shall certify compliance with the terms and conditions contained in this Part 70 OP, including emission limitations, standards, work practices, and the means for monitoring such compliance. *[AQR 12.5.2.8(e)]*

6. The permittee shall submit compliance certifications annually in writing to the Control Officer (4701 W. Russell Road, Suite 200, Las Vegas, NV 89118) and the Region 9 Administrator (Director, Air and Toxics Divisions, 75 Hawthorne St., San Francisco, CA 94105). A compliance certification for each calendar year will be due on January 30 of the following year, and shall include the following: *[AQR 12.5.2.8(e)]*

    a. The identification of each term or condition of the permit that is the basis of the certification;

    b. The identification of the methods or other means used by the permittee for determining the compliance status with each term and condition during the certification period. These methods and means shall include, at a minimum, the monitoring and related recordkeeping and reporting requirements described in 40 CFR Part 70.6(a)(3). If necessary, the permittee shall also identify any other material information that must be included in the certification to comply with Section 113(c)(2) of the Clean Air Act, which prohibits knowingly making a false certification or omitting material information; and

    c. The status of compliance with the terms and conditions of the permit for the period covered by the certification, including whether compliance during the period was continuous or intermittent. The certification shall be based on the methods or means designated in (b) above. The certification shall identify each deviation and take it into account in the compliance certification. The certification shall also identify, as possible exceptions to compliance, any periods during which compliance was required and in which an excursion or exceedance, as defined under 40 CFR Part 64, occurred.

7. The permittee shall report to the Control Officer any startup, shutdown, malfunction, emergency, or deviation that causes emissions of regulated air pollutants in excess of any limits set by regulations or this permit. The report shall be in two parts, as specified below: *[AQR 12.5.2.6(d)(4)(B); AQR 25.6.1]*

a. Within 24 hours of the time the permittee learns of the event, the permittee shall notify DAQ by phone at (702) 455-5942, by fax at (702) 383-9994, or by email at airquality@clarkcountynv.gov.

b. Within 72 hours of the required notification, the permittee shall submit a detailed written report to DAQ containing the information required by AQR 25.6.3.

8. With the semiannual monitoring report, the permittee shall report to the Control Officer all deviations from permit conditions that do not result in excess emissions, including those attributable to malfunction, startup, or shutdown. Reports shall identify the probable cause of each deviation and any corrective actions or preventative measures taken. *[AQR 12.5.2.6(d)(4)(B)]*

9. The owner or operator of any source required to obtain a permit under AQR 12 shall report to the Control Officer emissions in excess of an applicable requirement or emission limit that pose a potential imminent and substantial danger to public health and safety or the environment as soon as possible, but no later than 12 hours after the deviation is discovered, and submit a written report within two days of the occurrence. *[AQR 25.6.2]*

E. PERFORMANCE TESTING REQUIREMENTS

1. Upon request of the Control Officer, the permittee shall test or have tests performed to determine emissions of air contaminants from any source whenever the Control Officer has reason to believe that an emission in excess of those allowed by the AQRs is occurring. The Control Officer may specify testing methods to be used in accordance with good professional practice. The Control Officer may observe the testing. All tests shall be conducted by reputable, qualified personnel. *[AQR 4.2]*

2. Upon request of the Control Officer, the permittee shall provide necessary holes in stacks or ducts and such other safe and proper sampling and testing facilities, exclusive of instruments and sensing devices, as may be necessary for proper determination of the emission of air contaminants. *[AQR 4.2]*

3. The permittee shall submit to the Control Officer for approval a performance testing protocol that contains testing, reporting, and notification schedules, test protocols, and anticipated test dates no less than 45 days, but no more than 90 days, before the anticipated date of the performance test unless otherwise specified in Section III.F of this permit. *[AQR 12.5.2.8]*

4. The permittee shall submit to EPA for approval any alternative test methods EPA has not already approved to demonstrate compliance with a requirement under 40 CFR Part 60. *[40 CFR Part 60.8(b)]*

5. The permittee shall submit a report describing the results of each performance test to the Control Officer within 60 days of the end of the test. *[AQR 12.5.2.8]*

II. EMISSION UNITS AND APPLICABLE REQUIREMENTS

A. EMISSION UNITS

1. The stationary source covered by this Part 70 OP is defined to consist of the emission units and associated appurtenances summarized in Table II-A-1. *[Renewal Application 1/31/2019, AQR 12.5.2.3 and AQR 12.5.6.2]*

Table II-A-1: List of Emission Units

EU	Rating	Description	Make	Model No.	Serial No.
A01	35 MW	Combustion Turbine Generator #1 with a fired HRSG	GE	PG6541B	295525
A02	35 MW	Combustion Turbine Generator #2 with a fired HRSG	GE	PG6541B	295524
A03	520 hp	Detroit Diesel Starter Engine, Combustion Turbine Generator #1	Detroit	71237300	12VA083956
A04	520 hp	Detroit Diesel Starter Engine, Combustion Turbine Generator #2	Detroit	71237300	12VA083901
A05	218 MMBtu/h	Auxiliary Boiler #1	Indeck/ Volcano	0-7-2000	
A06	86 MMBtu/hr	Auxiliary Boiler #2	Nebraska	NOS 2A/S-55	032-88
A09a	7,666 gpm each	Cooling Tower, 3 cells	Thermal-Dynamics Towers Inc.	TD-3030-3-2424CF	
A09b					
A09c					
F05	25 MMBtu/hr	Supplemental Duct Burner, Skid #1	John Zink	LDR-11-LE	S82733
F05a	25 MMBtu/hr	Supplemental Duct Burner, Skid #1	John Zink	LDR-11-LE	S82733
F06	25 MMBtu/hr	Supplemental Duct Burner, Skid #2	John Zink	LDR-11-LE	S82733
F06a	25 MMBtu/hr	Supplemental Duct Burner, Skid #2	John Zink	LDR-11-LE	S82733

B. INSIGNIFICANT ACTIVITIES

1. The units in Table II-B-1 are present at this source, but are insignificant activities pursuant to AQR 12.5.

Table II-B-1: Insignificant Activities

Description
Facility Maintenance (Painting)
Sandblaster
Degreaser that uses Mirachem 500
Fuel Oil Transfer Pumps
Fuel Oil Unloading
Natural Gas Metering Station
Natural Gas Coalescing Filters
Lube Oil System-CTG-01
Lube Oil System-CTG-02

Description
Lube Oil System-CTG-03
Water Storage Tank (750,000 gallon)
21.8 hp Water Pump
Ammonia Storage/Injection (12,000 gallons)
29.1-MW extraction/condensing steam turbine generator system[1]
Temporary Fuel Storage Tank (21,000 gallons)

[1]This unit has been identified as process equipment with no emissions.

C. NONROAD ENGINES

1. Pursuant to Title 40, Part 1068.30 of the Code of Federal Regulations (40 CFR Part 1068.30), nonroad engines that are portable or transportable (i.e., not used on self-propelled equipment) shall not remain at a location for more than 12 consecutive months; otherwise, the engine(s) will constitute a stationary reciprocating internal combustion engine (RICE) and be subject to the applicable requirements of 40 CFR Part 63, Subpart ZZZZ; 40 CFR Part 60, Subpart IIII; and/or 40 CFR Part 60, Subpart JJJJ. Stationary RICE shall be permitted as emission units upon commencing operation at this stationary source. Records of location changes for portable or transportable nonroad engines shall be maintained, and shall be made available to the Control Officer upon request. These records are not required for engines owned and operated by a contractor for maintenance and construction activities, as long as records are maintained demonstrating that such work took place at the stationary source for periods less than 12 consecutive months. *[AQR 12.5.6.2]*

2. Nonroad engines used on self-propelled equipment do not have this 12-month limitation or the associated recordkeeping requirements. *[AQR 12.5.6.2]*

D. EMISSION LIMITS AND STANDARDS

1. **Emission Limits**

    a. The permittee shall, under all conditions, maintain and operate the source in a manner consistent with good air pollution control practice for minimizing emissions as required by 40 CFR Part 60.11. *[AQR 12.5.2]*

    b. Neither the actual nor the allowable emissions shall exceed the calculated PTE for each emission unit listed in Table II-D-1. Tons-per-year emission limits for each emission unit are based on consecutive 12-month totals and include startup and shutdown emissions. *[NSR ATC 393, Modification 7, Revision 2 (12/15/2008) and Application for Minor Revision of Part 70 OP (11/24/2015)]*

Table II-D-1: Emission Unit PTE, Including Startup and Shutdowns (tons per year)

EU	Condition	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP
A01[1] F05, F05a[2]	8,760 hr/yr combined fuel	14.43	14.43	69.24	39.42	6.31	4.29	2.03
A02[1], F06, F06a[2]	8,760 hr/yr combined fuel	14.43	14.43	69.24	39.42	6.31	4.29	2.03
A03	125 hr/yr	0.07	0.07	1.01	0.22	0.01	0.08	0.01
A04	125 hr/yr	0.07	0.07	1.01	0.22	0.01	0.08	0.01
A05	8,760 hr/yr	6.66	6.66	13.94	0.86	0.57	4.47	4.47
A06	6,000 hr/yr	1.29	1.29	9.33	9.99	0.15	0.15	0.49
A09	8,760 hr/yr	1.80	1.08	0	0	0	0	0

[1] Annual emissions based on worst-case scenario of 480 hours/consecutive 12-months of diesel combustion and 8,280 hours/consecutive 12-months of natural gas combustion.
[2]The supplemental-firing duct burners make up the HRSG.

Table II-D-2: Emission Rate (pounds per hour) Limitations, Excluding Startup and Shutdowns

EU	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP
A01[1]	2.50	2.50	15.20	9.00	0.27	0.92	0.46
A01[2]	17.00	17.00	26.30	9.00	21.64	2.00	0.54
A02[1]	2.50	2.50	15.20	9.00	0.27	0.92	0.46
A02[2]	17.00	17.00	26.30	9.00	21.64	2.00	0.54
A05	1.52	1.52	3.18	0.20	0.13	1.02	1.02
A06	0.43	0.43	3.11	3.33	0.05	0.05	0.16

[1]Emissions based on natural gas combustion in the turbines.
[2]Emissions from the combustion of diesel fuel only.
[3]Only emission units that require performance testing are included in this table.

Table II-D-3: Emission Concentration (ppmvd) Limitations, Excluding Startup and Shutdowns

EU	O_2 Standard	NO_X (ppmvd)		CO (ppmvd)	
		Natural Gas	Diesel	Natural Gas	Diesel
A01[1] F05, F05a	15%	10	17	10	10
A02[1] F06, F06a	15%	10	17	10	10
A05[2]	3%	12		1.2	
A06	3%	30		400	

[1]Emissions from the combustion of natural gas or distillate are calculated using a 4-hour rolling average (except CO for EU: A05), not to include startup or shutdown.
[2]CO for EU: A05 is based on 24 hours.

Turbines/Duct Burners

c. The permittee shall not exceed emission rate limits listed in Table II-D-2 for NO_X and CO for the turbines (EUs: A01 and A02) as determined by the CEMS as described in Section II-F, excluding any startup or shutdown period. *[NSR ATC 393, Modification 7, Revision 2 (12/15/2008)]*

d. The permittee shall operate each turbine and duct burner combination (EUs: A01, F05, F05a, A02, F06, and F06a) such that they do not emit NO_X in concentrations greater than 17 ppmvd at 15% O_2 while combusting diesel or greater than 10 ppmvd at 15% O_2 while combusting natural gas during any 4-hour rolling averaging period, excluding any startup or shutdown period. *[NSR ATC 393, Modification 7, Revision 2 (12/15/2008)]*

e. The permittee shall operate each turbine and duct burner combination (EUs: A01, F05, F05a, A02, F06, and F06a) such that they do not emit CO in concentrations greater than 10 ppmvd at 15% O_2 while combusting either diesel or natural gas during any 4-hour rolling averaging period, excluding any startup or shutdown period. *[NSR ATC 393, Modification 7, Revision 2 (12/15/2008)]*

Boilers

f. The permittee shall not exceed emission rate limits listed in Table II-D-2 for NO_X and CO for the boiler (EU: A05) as determined by the CEMS as described in Section II-F, excluding any startup or shutdown period. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

g. The permittee shall not exceed emission concentration limits listed in Table II-D-3 for NO_X, for any 4-hour rolling averaging period, or CO, for any 24-hour rolling averaging period, for the boiler (EU: A05) as determined by the CEMS as described in Section II-F, excluding any startup or shutdown period. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

h. The permittee shall operate the boiler (EU: A05) such that it emits neither more than 12 ppmvd NO_X, during a 4-hour rolling average, nor 1.2 ppmvd CO, during a 24-hour rolling average, corrected to 3% O_2, excluding any startup or shutdown period. *[NSR ATC 393, Modification 7, Revision 2 (12/15/2008)]*

i. The permittee shall not exceed emission rate limits listed in Table II-D-2 for NO_X and CO for the boiler (EU: A06), excluding any startup or shutdown period. *[NSR ATC 393, Modification 7, Revision 2 (12/15/2008)]*

j. The permittee shall operate the boiler (EU: A06) such that it emits neither more than 30 ppmvd NO_X nor 400 ppmvd CO, corrected to 3% O_2, excluding any startup or shutdown period. *[NSR ATC 393, Modification 7, Revision 2 (12/15/2008)]*

Other

k. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant in excess of an average of 20% opacity for a period of more than 6 consecutive minutes. *[AQR 26.1]*

2. **Operational Limits**

a. The permittee shall limit the fuel inputs for each emission unit to the values listed in Table II-D-4. *[NSR ATC 393, Modification 7 (03/19/2008) and Title V Renewal (00393_20131020_APP) incorporated into the Title V]*

Table II-D-4: Fuel Limitations for Combustion Equipment

EU	Equipment	Fuel Type	Max. Hourly (MMBtu)	Max. Consecutive 12 months (MMBtu)
A01/A02	Each Combustion Turbine[1]	Natural gas	447	3,915,720
F05/F05a F06/F06a	Each Duct Burner	Natural gas	25	219,000
A05	Indeck/Volcano Boiler	Natural gas	218	1,909,680
		Hydrogen		
A06	Nebraska Auxiliary Boiler	Natural gas	86	510,000

[1]Based upon 8,760 hours at 100% load at 105^{0}F.

Turbines/Duct Burners

b. The permittee shall limit the natural gas fuel rate to 447 MMBtu/hour for each combustion turbine (EUs: A01 and A02) based on an annual average, the lower heating value (LHV), and standard conditions. Standard conditions shall be defined as 105ºF and 13.78 pounds per square inch absolute (psia) at 16% relative humidity. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

c. The permittee may operate each turbine unit (EUs: A01 and A02), upon demonstration of compliance with the emission standards, up to 480 hours per year based on consecutive 12-months while combusting low sulfur diesel fuel (<0.05% by weight). *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

d. The permittee shall not combust diesel in the turbines (EUs: A01 and A02) during the summer months (June 1 - August 31) except when there is a loss of natural gas, or testing is required. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

e. The permittee shall limit the diesel fuel consumption to 3,035 gallons per hour for each turbine (EUs: A01 and A02). *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

f. The permittee shall limit heat input of each duct burner (EUs: F05, F05a, F06 and F06a) to 25 MMBtu/hour. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

g. A startup period for turbines (EUs: A01 and A02) is defined as the period of time of no more than 1 hour immediately following the application of a load. Startup periods shall be included in determining compliance with consecutive 12-months emissions limits for the emission units being started. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

h. A shutdown period for turbines (EUs: A01 and A02) shall begin when heat input falls below 50% of nameplate capacity and ends when combustion has ceased, the duration of the shutdown period should not exceed 60 minutes. Shutdown periods shall be

included in determining compliance with consecutive 12-months emissions limits for the emission units being shutdown. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

i. Emissions from startup and shutdown events when combined with the turbine emissions during normal operations, shall not exceed the consecutive 12-months limits outlined in Table II-D-1. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

j. The permittee shall use emission factors presented in the TSD for any clock hour in which a startup/shutdown event occurs, if the CEMS data does not include the actual startup/shutdown emissions. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

Engines

k. The permittee shall limit operation of each turbine starter engine (EUs: A03 and A04) to 125 hours per year based on consecutive 12-months. [NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]

Boilers

l. The permittee shall combust only natural gas, hydrogen fuel, or a combination of natural gas and hydrogen fuel in the Indeck/Volcano boiler (EU: A05). *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

m. The permittee shall limit the operation of the Indeck/Volcano boiler (EU: A05) to 1,909,680 MMBtu per year of natural gas and hydrogen fuel. *[NSR ATC 393, Modification 7, Revision 2 (12/15/2008)]*

n. A startup period of the Indeck/Volcano boiler (EU: A05) is defined as the period of time of no more than one hundred (100) minutes immediately following the firing of the burner. Startup periods shall be included in determining compliance with consecutive 12-months emissions for the Indeck/Volcano boiler. *[NSR ATC 393, Modification 7, Revision 2 (12/15/2008)]*

o. A shutdown period of the Indeck/Volcano boiler (EU: A05) shall begin when heat input falls below 15 percent of nameplate capacity and ends when combustion has ceased and shall not exceed 1 hour. Shutdown periods shall be included in determining compliance with consecutive 12-months emissions limits for the Indeck/Volcano boiler. *[NSR ATC 393, Modification 7, Revision 2 (12/15/2008)]*

p. The permittee shall limit the operation of the Nebraska boiler (EU: A06) to 510,000 MMBtu per consecutive 12-months. Only natural gas fuel shall be combusted in the boiler. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

q. The permittee shall limit the hours of operation of the Nebraska boiler (EU: A06) to 6,000 hours per any consecutive 12-months. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

E. EMISSION CONTROLS

1. Control Requirements

a. The permittee must comply with the control requirements contained in this section. If there is inconsistency between standards or requirements, the most stringent standard or requirement shall apply. *[AQR 12.5.2.6(a)]*

Turbines/Duct Burners

b. The permittee shall install, maintain and operate SCR on each of the turbine units **(**EUs: A01 and A02). The permittee shall operate SCR at all times the associated turbine unit is operating excluding periods of startup and shutdown. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

c. The permittee shall operate each SCR system on all turbine units in accordance with the operations and maintenance (O&M) manual. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

d. The permittee shall further control NO_X emissions from turbine units (EUs: A01 and A02) with steam injection, except during startup. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006) and Title V Renewal (00393_20131020_APP) incorporated into the Title V]*

e. The permittee shall operate each SCR system such that NO_X emissions do not exceed the limitations listed in Tables II-D-2 and II-D-3 excluding startups and shutdowns. *[AQR 12.5.2.6(a)]*

f. The permittee shall control SO_2 exhaust emissions from each combined cycle system by the exclusive use of pipeline quality natural gas with a maximum total sulfur content of 0.50 grains/100 dscf and good combustion practice. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

g. The permittee shall control PM_{10} exhaust emissions from each combined cycle system by properly maintained and periodically replaced inlet air filters preceding each turbine, per O&M manual and good operating practice. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

Engines

h. The permittee shall operate and maintain each turbine starter engine in accordance with the manufacturer's operations and maintenance (O&M) manual for emissions-related components (EUs: A03 and A04)

i. The permittee shall combust only low sulfur (<0.05% sulfur by weight) diesel fuel in each turbine starter engines (EUs: A03 and A04). *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

Boilers

j. The permittee shall combust only natural gas and hydrogen fuel in boiler (EU: A05).

k. The permittee shall combust only natural gas in boiler (EU: A06).

l. The permittee shall operate and maintain each boiler (EU: A05 and A06) in accordance with the manufacturer's operations and maintenance (O&M) manual for emissions-related components and good combustion practices.

Cooling Tower

m. The permittee shall operate and maintain the cooling tower in accordance with the manufacturer's recommendations. No chromium-containing compounds shall be used for water treatment (EU: A09). *[AQR 12.5.2.6(a)]*

n. The permittee shall equip each cooling tower with drift eliminators with a manufacturer's maximum drift rate of 0.002% (EU: A09). *[Title V Renewal 11/20/2014]*

o. The permittee shall maintain the cooling water such that the maximum TDS content shall not exceed 3,800 ppm (EU: A09). *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

F. MONITORING

1. Visible Emissions

a. The permittee shall perform visual emissions checks each calendar quarter on each fuel-burning emission unit (EUs: A01, A02, A03, and A04) while it is in operation and when firing diesel fuel. If visible emissions are observed, then corrective actions shall be taken to minimize the emissions, and the opacity of the emissions shall be visually determined in accordance with 40 CFR Part 60, Appendix A-4 (Test Method 9). *[AQR 12.5.2.6(d) and 40 CFR Part 70.6]*

2. Continuous Emissions Monitoring System

b. To demonstrate continuous direct compliance with all emission limitations for NO_x and CO specified in this permit, the permittee shall install, calibrate, maintain, operate, and certify CEMS for NO_x, CO, and O_2 on each stationary gas turbine unit (EUs: A01 and A02) in accordance with 40 CFR Part 60. Each CEMS shall include an automated data acquisition and handling system. Each system shall monitor and record at least the following data: *[AQR 12.5.2.6(d)]*

i. 4-hour rolling averages of exhaust gas concentration for each of NO_x, CO, and diluent $O_{2;}$

ii. Exhaust gas flow rate (by direct or indirect methods);

iii. Fuel flow rate;

iv. Hours of operation;

v. Hourly, daily and quarterly accumulated mass emissions of NO_x and CO; and

vi. Hours of downtime of the CEMS.

c. The permittee shall install, calibrate, maintain, operate, and certify CEMS for NO_x, CO, and O_2 on the Indeck/Volcano boiler (EU: A05) in accordance with 40 CFR Part 60. Each CEMS shall include an automated data acquisition and handling system. Each system shall monitor and record at least the following data: *[AQR 12.5.2.6(d)]*

i. 4-hour rolling averages of exhaust gas concentration for NO_x and diluent O_2;

ii. 24-hour rolling averages of exhaust gas concentration for CO and diluent O_2;

iii. Exhaust gas flow rate (by direct or indirect methods);

iv. Fuel flow rate;

v. Hours of operation;

vi. Hourly, daily and quarterly accumulated mass emissions of NO_X and CO; and

vii. Hours of downtime of the CEMS.

d. The permittee shall submit all periodic audit procedures and QA/QC procedures for CEMS to conform to the provisions of 40 CFR Part 60, Appendix F.

e. The permittee shall conduct annual relative accuracy test audits (RATA) of the CO, NO_x, and O_2 CEMS. *[AQR 12.5.2.6(d)]*

3. **Other**

Boilers

f. The permittee shall install a fuel flow meter for the Nebraska boiler (EU: A06), and shall monitor the monthly fuel consumption. *[AQR 12.5.2.6(d)]*

g. The permittee shall operate the Nebraska boiler with a nonresettable hour meter (or other device the Control Officer has approved in advance), monitor its hours of operation, and calculate them on a monthly basis as a consecutive 12-month total (EU: A06). *[AQR 12.5.2.6(d)]*

h. The permittee shall conduct a burner efficiency test (boiler tune-up) and inspection on the auxiliary boilers (EUs: A05 and A06) semiannually. *[AQR 12.5.2.6(d)]*

i. The permittee shall conduct burner efficiency test in accordance with the manufacturer's recommendations and specifications for good combustion practices. The permittee may use an alternative method to determine burner efficiency upon prior approval from the Control Officer. *[AQR 12.5.2.6(d)]*

j. The permittee may perform a burner efficiency test once each calendar year if the actual hours of operation are less than 50. To exercise this option, the permittee must install an hour meter and begin keeping written records before the start of the calendar year (EUs: A05 and A06*). [AQR 12.5.2.6(d)]*

k. The permittee may replace one contemporaneously-required burner efficiency test with a performance test that has acceptable results (EUs: A05 and A06*). [AQR 12.5.2.6(d)]*

Cooling Tower

l. The permittee shall monitor the TDS of the cooling tower recirculation water monthly using a conductivity meter or another device the Control Officer has approved in advance (EU: C01). *[AQR 12.5.2.6(d)]*

G. TESTING

1. The permittee is subject to performance testing in accordance with 40 CFR Part 60, Subparts A, Db, Dc, and GG, and *DAQ's Source Testing Guidelines* (as revised). *[AQR 12.5.2.6(d) and 40 CFR Part 60.335]*

Turbines/Duct Burners

2. The permittee shall conduct initial performance tests for NO_x and CO while using natural gas on each of the turbine units (EUs: A01 and A02) to demonstrate compliance with the emission limitations. Table II-G-1 summarizes performance test methods, including for NO_x and CO, for the turbine package units. The initial performance tests for both units were completed on April 7, 2008. *[AQR 12.5.2.6(d)]*

Table II-G-1: Performance Testing Requirements (40 CFR Part 60, Appendix A)

Test Point	Pollutant	Method
Turbine Exhaust Stack	NO_X	Chemiluminescence Analyzer (EPA Method 7E)
Turbine Exhaust Stack	CO	EPA Method 10
Turbine Exhaust Stack	PM_{10}	EPA Method 201/202 or 201A/202
Turbine Exhaust Stack	Opacity	EPA Method 9
Stack Gas Parameters	—	EPA Methods 1, 2, 3, 4

3. Subsequent performance testing for NO_x and CO while firing natural gas in the turbines (EUs: A01 and A02) shall be conducted upon written notification from the Control Officer. *[AQR 12.5.2.6(d)]*

Boilers

4. The permittee shall conduct a performance test on the auxiliary boilers (EUs: A05 and A06) to demonstrate initial compliance with the CO and NO_x emissions limitations. Table II-G-2 summarizes performance test methods, including for NO_x and CO, for the turbine package units.no later than 180 days after initial startup and within 60 days of achieving the maximum production rate at which the affected facility will be operated. This testing was completed for EUs: A05 and A06 in February 2016 and February 2017, respectively.

5. An initial performance test shall be performed on EU: A05 after installation of the low-NO_x burner coupled with the CO oxidation catalyst. This testing has been completed for EU: A05. *[AQR 12.5.2.6(d), NSR Mod. 7, Rev 2]*

6. Subsequent performance testing shall be conducted on the auxiliary boiler (EU: A06) at least once every five years.

7. Subsequent performance testing for NO_x and CO while firing natural gas in the boiler (EU: A05) may be required by the Control Officer. *[AQR 12.5.2.6(d)]*

Table II-G-2: Performance Testing Requirements (40 CFR Part 60, Appendix A)

Test Point	Pollutant	Method
Boiler Exhaust Stack	NO_X	Chemiluminescence Analyzer (EPA Method 7E)
Boiler Exhaust Stack	CO	EPA Method 10
Stack Gas Parameters	—	EPA Methods 1, 2, 3, 4

H. RECORDKEEPING

1. The permittee shall keep on-site all records and logs, or copies thereof, for a minimum of five years from the date the measurement or data was entered. *[AQR 12.5.2.6(d)]*

2. The permittee shall maintain records on-site that include, at a minimum: *[AQR 12.5.2.6]*

<u>*Turbines/Duct Burners*</u>

a. Dates, times, and duration of each startup and shutdown cycle (EUs: A01, A02);

b. Startup and shutdown emissions per turbine (EUs: A01, A02) in pounds per hour and yearly emissions, including startup, shutdown and normal operations, in tons per each consecutive 12-month period;

c. Sulfur content of natural gas, as certified by the supplier. Sulfur content of natural gas fuel shall be verified by the permittee at least quarterly, and verifications shall be based on reports or written data from the gas supplier, as required by 40 CFR Part 60; *[AQR 12.5.2.6(d)]*

d. Name of diesel fuel supplier, sulfur content of diesel fuel, and method used to determine sulfur content of diesel fuel;

e. Supplier certification of sulfur content of diesel fuel, which shall accompany each fuel delivery*; [AQR 12.5.2.6(d]*

<u>*Boilers*</u>

f. Dates, times, and duration of each startup and shutdown cycle (EU: A05);

g. Monthly, consecutive 12-month total quantity of natural gas and hydrogen fuel used for the Indeck/Volcano boiler in MMBtu (EU: A05);

h. Monthly, consecutive 12-month total quantity of natural gas fuel used for the Nebraska boiler in MMBtu (EU: A06);

<u>*Cooling Tower*</u>

i. Daily TDS content of cooling tower circulation water, when operating (EU: A09);

<u>*Other*</u>

j. Results of the last performance test conducted, in addition to any other performance tests conducted within the last five years;

k. Burner efficiency test results

l. Quality assurance plan for all CEMS;

m. All CEMS information required by 40 CFR Part 60, including a CEMS monitoring plan;

n. Log of visible emission checks;

o. Records of location changes for nonroad engines, if applicable; and

p. For all inspections, visible emission checks, and testing required under monitoring, all the logs, reports, and records shall include at least the date and time, the name of the person performing the action, the results or findings, and the type of corrective action taken (if required). *[AQR 12.5.2.6(d)]*.

3. The permittee shall maintain records on-site that require semiannual reporting and include, at a minimum: *[AQR 12.5.2.6]*

Turbines/Duct Burners

a. The magnitude and duration of excess emissions, permit deviations, notifications, monitoring system performance, malfunctions, corrective actions taken, etc., as required by 40 CFR Part 60.7;

b. Monthly, consecutive 12-month total hours of operation for each turbine, with diesel and natural gas noted separately, and, as applicable, for each duct burner;

c. Monthly, consecutive 12-month total quantity of natural gas and diesel fuel consumed in each gas turbine in MMBtu;

Boilers

d. Monthly, consecutive 12-month total quantity of combined fuel input of natural gas and hydrogen fuel in the Indeck/Volcano boiler (EU: A05) in MMBtu;

e. Monthly, consecutive 12-month total quantity of natural gas fuel input to the Nebraska boiler (EU: A06) in MMBtu;

f. Monthly, consecutive 12-month total hours of operation of the Nebraska boiler (EU: A06);

Engines

g. Monthly and consecutive 12-month total hours of operation for each starter engine (EUs: A03 and A04); and

Other

h. CEMS audit results or accuracy checks, corrective actions, etc., as required by 40 CFR Part 60, Appendix F, and the CEMS quality assurance plan (EUs: A01, A02 and A05);

i. Time, duration, nature and probable cause of any CEMS downtime and corrective actions taken;

j. Monthly CEMS NO_X and CO (EUs: A01, A02 and A05);

k. Monthly, consecutive 12-month total emissions for each emission unit in tons per year.

4. Records and data required by this permit to be maintained by the permittee may, at the permittee's expense, be audited at any time by a third party selected by the Control Officer. This third party shall be subject to the same business confidentiality terms binding DAQ during investigations and data gathering. *[AQR 12.5.2.6(d)]*

I. REPORTING

1. The permittee shall comply with all applicable notifications and reporting requirements of 40 CFR Part 60.7, 40 CFR Part 60, Subparts Db, Dc, and GG, and 40 CFR Part 63, Subpart ZZZZ. *[AQR 12.5.2.6(d)]*
2. All report submissions shall be addressed to the attention of the Control Officer. *[AQR 12.5.2.8(e)(4)]*
3. Regardless of the date of issuance of this permit, the source shall comply with the schedule for report submissions outlined in Table II-I-1 *[AQR 12.5.2.6(d)]*.

Table II-I-1: Required Submittal Dates for Various Reports

Required Report	Applicable Period	Due Date[1]
Semiannual report for 1st six-month period	January, February, March, April, May, June	July 30 each year
Semiannual report for 2nd six-month period, and any additional annual records required	July, August, September, October, November, December	January 30 each year
Annual Compliance Certification	Calendar year	January 30 each year
Annual Emissions Inventory Report	Calendar year	March 31 each year
Annual Emissions Statement[2]	Calendar year	March 31 each year[1]
Notification of Malfunctions, Startup, Shutdowns or Deviations with Excess Emission	As required	Within 24 hours of the time the permittee learns of the event
Report of Malfunctions, Startup, Shutdowns or Deviations with Excess Emission	As required	Within 72 hours of DAQ notification
Deviation Report without Excess Emissions	As required	With semiannual reports
Excess Emissions that Pose a Potential Imminent and Substantial Danger	As required	Within 12 hours of the permittee learns of the event
Performance Testing Protocol	As required	No less than 45 days, but no more than 90 days, before the anticipated test date[1]
Performance Testing	As required	Within 60 days of the end of the test

[1]If the due date falls on a Saturday, Sunday, or federal or Nevada holiday, then the submittal is due on the next regularly scheduled business day.

[2] Required only for stationary sources that emit 25 tons or more of nitrogen oxide (NO_X) and/or emit 25 tons or more of volatile organic compounds (VOC) during a calendar year.

4. All reports shall contain the following: *[AQR 12.5.2.6(d)]*

    a. A certification statement on the first page, i.e., "I certify that, based on information and belief formed after reasonable inquiry, the statements contained in this document is true, accurate and complete." (A sample form is available from Air Quality); and

    b. A certification signature from a responsible official of the company and the date certification.

5. The permittee shall submit semiannual reports to the Control Officer. *[AQR 12.5.2.6(d)]*

6. The following requirements apply to semiannual reports: *[AQR 12.5.2.6(d)]*

    a. The report shall include each item listed in Section II-H-3.

    b. The report shall include semiannual summaries of any permit deviations, their probable cause, and corrective or preventative actions taken.

7. The Control Officer reserves the right to require additional reports and reporting to verify compliance with permit conditions, permit requirements, and requirements of applicable federal regulations. *[AQR 4.1 and AQR 12.5.2.6(d)]*

III. OTHER REQUIREMENTS

1. The permittee shall not use, sell, or offer for sale any fluid as a substitute material for any motor vehicle, residential, commercial, or industrial air conditioning system, refrigerator freezer unit, or other cooling or heating device designated to use a chlorofluorocarbon or hydrochlorofluorocarbon compound as a working fluid unless such fluid has been approved for sale in such use by the Administrator. The permittee shall keep record of all paperwork relevant to the applicable requirements of 40 CFR Part 82 on-site. *[40 CFR Part 82]*
2. Saguaro is exempted, based on the applicability criteria defined in 40 CFR Part 72.6(b)(5); therefore, the provisions of the acid rain regulations do not apply. *[40 CFR Part 72.6]*

IV. PERMIT SHIELD

1. Compliance with the terms contained in this permit shall be deemed compliance with the following applicable requirements in effect on the date of permit issuance: *[Renewal Application 1/31/2019, AQR 12.5.2.9]*

Table IV-1: Applicable Requirements Related to Permit Shield

Citation	Title
40 CFR Part 60, Subpart Db	NSPS – Industrial-Commercial-Institutional Steam Generating Units
40 CFR Part 60, Subpart Dc	NSPS – Small Industrial-Commercial-Institutional Steam Generating Units
40 CFR Part 60, Subpart GG	NSPS – Stationary Gas Turbines
40 CFR Part 63, Subpart ZZZZ	NESHAP – Stationary Reciprocating Internal Combustion Engines

Table IV-2: Streamlined Requirements Related to Permit Shield

				Value Comparison (in Units of the Permit Limit)			Averaging Period Comparison			
EU	Regulation (40 CFR)	Regulatory Standard	Permit Limit	Standard Value	Permit Limit Value	Is Permit Limit Equal or More Stringent?	Standard Averaging Period	Permit Limit Averaging Period	Is Permit Limit Equal or More Stringent?	Streamlining Statement for Shielding Purposes
A13	63.6640 (ZZZZ)	100 hours/year for testing and maintenance; 50 hours per year for non-emergency situations	100 hours/year for testing and maintenance; 50 hours per year for non-emergency situations	100; 50	100; 50	Yes	hours/year	hours/year	Yes	The permit limits are equal to the standard based on hours/year. Compliance with the permit demonstrates compliance with the standard.
A13	63.6603, Table 2d (ZZZZ)	Change oil and filter every 500 hours of operation or annually, whichever comes first; Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and Inspect all hoses and belts every 500 hours of operation or annually, whichevre comes first, and replace as necessary. Sources have the option to utilize an oil analysis program as described in 63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2d of this subpart.	Change oil and filter every 500 hours of operation or annually, whichever comes first; Inspect air cleaners every 1,000 hours of operation or annually, whichever comes first; and Inspect all hoses and belts every 500 hours of operation or annually, whichevre comes first, and replace as necessary. The Permittee may utilize an oil analysis program as described in Subpart 63.6625(i) in order to extend the specified oil change requirement and can petition the Control Officer pursuant to the requriements of 40 CFR 63.6(g) for alternative work practices.	500 or annually; 1,000 or annually; 500 or annually	500 or annually; 1,000 or annually; 500 or annually	Yes	hours or annually	hours or annually	Yes	The permit limits are equal to the standard based on hours or annually. Compliance with the permit demonstrates compliance with the standard.
A05	60.42b (Db)	0.20 lb/MMBtu SO_2	0.13 lb/hr SO_2	43.6	0.13	Yes	Not specified	Not specified	N/A	The permit limit is more stringent than the standard. Compliance with the permit demonstrates compliance with the standard.
A05	60.44b (Db)	0.20 lb/MMBtu NOx	12 ppm NOx @3% O_2	170	12	Yes	30-day rolling average	4-hour rolling average	Yes	The permit limit is more stringent than the standard. Compliance with the permit demonstrates compliance with the standard.
A06	60.48c (Dc)	The owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO_2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.	30 ppmvd NOx @3% O_2 400 ppmvd CO @3% O_2 Records and logs shall contain, at minimum, the following information: monthly and rolling 12-month quantity of natural gas fuel used for the Nebraska boiler in MMBtu	N/A	30; 400	N/A - there is no corresponding standard	N/A	4-hour rolling average	N/A - there is no corresponding standard	The recordkeeping requirement in the permit is more stringent than the standard. Complinace with the permit demonstrates complinace with the standard's recordkeeping requirement.
A01/A02	60.332 (GG)	0.0075% by volume NOx at 15% O_2, dry basis	10 ppmvd NOx @15% O_2 (natural gas) 17 ppmvd NOx @15% O_2 (fuel oil)	75	10; 17	Yes	4-hour rolling average	4-hour rolling average	Yes	The permit limit is more stringent than the standard. Compliance with the permit demonstrates compliance with the standard.
A01/A02	60.333 (GG)	0.015% by volume SO_2 at 15% O_2, dry basis	0.27 lb/hr SO_2 (worst case combination of natural gas and diesel fuel combustion) 21.64 lb/hr SO_2 (combustion of diesel fuel only)	345	0.27; 21.64	Yes	4-hour	1-hour	Yes	The permit limit is more stringent than the standard. Compliance with the permit demonstrates compliance with the standard.

ATTACHMENT 1 – APPLICABLE REGULATIONS

REQUIREMENTS SPECIFICALLY IDENTIFIED AS APPLICABLE:

1. NRS, Chapter 445B.

2. Applicable AQR sections, as listed in Table A-1.

Table A-1. Requirements Specifically Identified As Applicable—Local

Citation	Title
AQR Section 00	Definitions
AQR Section 04	Control Officer
AQR Section 05	Interference with Control Officer
AQR Section 08	Persons Liable for Penalties – Punishment: Defense
AQR Section 09	Civil Penalties
AQR Section 12.4	ATC Application and Permit Requirements for Part 70 Sources
AQR Section 12.5	Part 70 OP Requirements
AQR Section 13.2(b)(82)	NESHAP - Stationary Reciprocating Internal Combustion Engines
AQR Section 14.1(b)(4)	NSPS – Standards of Performance for Industrial-Commercial-Instittutional Steam Generating Units
AQR Section 14.1(b)(40)	NSPS – Standards of Performance for Stationary Gas Turbines
AQR Section 18	Permit and Technical Service Fees
AQR Section 25	Upset/Breakdown, Malfunctions
AQR Section 26	Emissions of Visible Air Contaminants
AQR Section 28	Fuel Burning Equipment
AQR Section 40	Prohibition of Nuisance Conditions
AQR Section 41	Fugitive Dust
AQR Section 42	Open Burning
AQR Section 43	Odors in the Ambient Air
AQR Section 70	Emergency Procedures
AQR Section 80	Circumvention

3. CAAA (authority: 42 U.S.C. § 7401, et seq.)

4. Applicable 40 CFR subsections, as listed in Table A-2.

Table A-2. Requirements Specifically Identified As Applicable—Federal

Citation	Title
40 CFR Part 52.21	PSD
40 CFR Part 52.1470	SIP Rules
40 CFR Part 60, Subpart A	NSPS – General Provisions
40 CFR Part 60, Subpart Db	NSPS – Industrial-Commercial-Institutional Steam Generating Units
40 CFR Part 60	Appendix A, Method 9 or equivalent (Opacity)
40 CFR Part 60, Subpart Dc	NSPS – Small Industrial-Commercial-Institutional Steam Generating Units
40 CFR Part 60, Subpart GG	NSPS – Standards of Performance for Stationary Gas Turbines

Citation	Title
40 CFR Part 68	Chemical Accident Prevention Provisions
40 CFR Part 70	State Operating Permit Programs
40 CFR Part 82	Protection of Stratospheric Ozone
40 CFR Part 63, Subpart ZZZZ	NESHAP — Stationary Reciprocating Internal Combustion Engines

Appendix B

RACT Analysis - PG6541B Turbines, Emission Units A01 and A02

APPENDIX B

RACT Analysis

PG6541B Turbines, Emission Units A01 and A02

Appendix B
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Attachments

1.0 General

This appendix summarizes the Reasonably Available Control Technology (RACT) Analysis performed for the GE PG6541B turbines, Emission Units (EU) A01 and A02, located at Saguaro Power Company (Saguaro). The basic steps for this analysis are as follows:

- Identification of existing equipment and baseline emissions
- Identification of available control options
- Elimination of technically infeasible control options
- Determination of the cost effectiveness of control options
- Evaluation of the benefits and disadvantages (environmental, energy and economic) associated with the technically feasible control options
- Identification of RACT control technology including emission limitations, monitoring, testing, recordkeeping and reporting requirements

Controls for oxides of nitrogen (NO_X) are evaluated in this appendix.

2.0 NO_X RACT Assessment

2.1 Equipment Description and Limitations

EUs A01 and A02 have nominal power rating of 35 MW. They burn natural gas but are permitted to allow combustion of #2 fuel oil in the event of natural gas curtailment. However, it is not feasible to run on #2 fuel oil as the fuel oil storage tanks were converted to water tanks and the engines are not configured to run on fuel oil. In practice, the facility would shut down in the event of natural gas curtailment. Accordingly, the worst-case fuel for these turbines is natural gas and the RACT analysis will be done for natural gas.

The GE PG6541B natural gas turbines are classified as combined cycle gas turbines as they are equipped with Heat Recovery Steam Generators (HRSGs) that power a conventional steam turbine. The HRSGs contain supplemental duct burners, but they are not used in practice and therefore will not be accounted for in this analysis.

2.2 Baseline Emissions

As noted in Section 3 of the report, baseline emissions can be set equivalent to actual emissions if actual emissions for the three previous consecutive years are 70% or less of the source's potential emissions. Saguaro meets this criterion on a facility-wide basis.

Table 1 summarizes the baseline NO_X emissions of the GE PB6541B natural gas combustion turbines, which are equipped with steam injection and Selective Catalytic Reduction (SCR) technologies as baseline controls.

Table 1 - Baseline Emissions

Emission Unit	NO_X Emissions[1] (tons)
A01	54.45
A02	55.17

Notes: [1] Maximum annual emissions for 2019 - 2021.

2.3 Identification and Technical Feasibility of NO_X Control Options

2.3.1. Identification of Available Controls

A review of the most recent (5 years) determinations contained in the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC) was conducted to identify any recent RACT determinations for combustion turbines of the same or comparable size. The database did not contain any such RACT determinations for this time period. In addition, locally permitted combustion turbines were researched and the combustion turbine manufacturer was queried to identify potential controls. Based on the information obtained, the proposed NO_X control technologies for EUs A01 and A02 are summarized in Table 2.

Table 2 - Available NO_X Control Technology Methods for EUs A01 and A02

Control Equipment	NO_X PPM Guarantee or Reduction Potential (%)	Range of Application	Commercial Availability/ R&D Status
Dry Low NO_X (DLN)	9 ppm NO_X	Primarily for new turbine installations	Available for new turbine packages
Steam/Water Injection	60	Usually combined with SCR	Available
Selective Non Catalytic Reduction (SNCR)	75-90	Primarily combustion engines	Available, but not widely used
Non-Selective Catalytic Reduction (NSCR)	Variable	Automobile industry	Available
Selective Catalytic Reduction (SCR)	75-90	Numerous combustion turbines at power plants throughout country	Available although long lead times for retrofits or new installations
Steam Injection with SCR	10 ppm NO_X	Baseline for this application	Available with certain turbine packages. Baseline for this application
DLN with SCR	4 ppm NO_X	Primarily for new turbine installations	Available

It should be noted that EMx© technology (formerly called $SCONO_X$) owned by Miratech Corporation has the potential for stringent NO_X and CO reduction, however, it is no longer being installed on units. Miratech indicated it is strictly being serviced on units already equipped with this technology. For this reason, EMx© was eliminated from consideration as it is not commercially available.

The technical feasibility of each available control option identified in this section will next be evaluated.

2.3.2. Dry Low NO_X (DLN)

DLN uses a lean mixture of gaseous fuel and compressed air to avoid formation of high temperature zones where high levels of NO_X are created. The lean mixture of gaseous fuel is produced by incorporating excess air to the mixture. This process enables cooling of the flame in the primary combustion zone, thus reducing formation of NO_X, and it requires a custom designed mixing chamber for each turbine. This would amount to a reconfiguration of each turbine by the manufacturer (GE), provided there is space available to accommodate the DLN equipment. At this time, it is unclear whether the DLN mixing chambers could physically be mounted on the Saguaro turbine packages. Significant engineering assessment and design work would need to be conducted before a final determination could be made. For purposes of this assessment, we will assume that the control technology can be physically installed. DLN can consistently maintain NO_X emission rates of 9 ppm NO_X @ 15% O_2. Upon review of the RACT/BACT/LAER clearinghouse and locally permitted turbines, DLN is typically combined with SCR to achieve NO_X outlet concentrations in the 2 to 6 ppm @ 15% O_2 range.

2.3.3. Steam/Water Injection

Steam/water injection increases the thermal mass by dilution and accordingly reduces peak temperatures in the flame zone. Water injection has the additional benefit of absorbing the latent heat of vaporization from the flame zone. The water-to-fuel weight ratio is typically less than one. This yields NO_X reductions of 60% or higher. However, water injection increases both CO and VOC emissions. This technology is technically feasible as steam injection is installed in the GE PG6541B turbines.

2.3.4. Selective Non-Catalytic Reduction (SNCR)

SNCR uses a nitrogen-based reagent (ammonia or urea) in a chemical reaction to reduce NO_X into molecular nitrogen and water vapor. The reagent is injected into the post combustion exhaust gas. SNCR system NO_X removal efficiency depends on the range of the processing temperatures; the most favorable temperature range is 1600ºF and 2100ºF. Urea is more advantageous as a reagent because it is not toxic, less volatile, and easier to handle and store. Urea also has higher efficiency in penetrating farther into the flue gas, hence enhancing the mixing with the flue gas. The SNCR system injects the reagent directly into the combustion chamber, where the flue gas is directly mixed with the reagent. SNCR injection and control system is capable of reducing NO_X emissions by 60% or greater.

As already mentioned, the efficiency of SNCR is determined by the exhaust gas temperature, and since the GE PG6541B exhaust temperature is significantly lower (600ºF - 900ºF), SNCR's efficiency will be compromised. Based on this limitation, SNCR is not a technically viable control option for NO_X emissions for these units.

2.3.5. Non Selective Catalytic Reduction (NSCR)

NSCR uses a catalyst for removing NO_X emissions from the exhaust gas. This technology is primarily used in the industries that utilize rich burning internal combustion engines, such as the automobile industry. The removal efficiency of the NSCR depends on high fuel concentrations with minimal oxygen present.

This type of environment (low oxygen concentration) does not occur in the combustion turbine exhaust, hence NSCR is not a technically feasible control technology for this application.

2.3.6. Selective Catalytic Reduction (SCR)

As discussed earlier, SCR along with steam injection is considered a baseline control for this application as these are installed on the GE PG6541B turbines for NO_X control. SCR reduces Nitrogen Oxides (NO_X) in the exhaust gas. The reduction process is activated by injecting a nitrogen-based agent (reagent), such as ammonia or urea, into the post combustion flue gas. With the help of a metal-based catalyst, the reagent reacts selectively with the flue gas NO_X within a specific temperature range to reduce the NO_X into molecular nitrogen (N_2) and water vapor (H_2O). The metal-based catalyst has activated sites and increases the rate of the reduction reaction. The catalyst is made of active metals or ceramics with a highly porous structure.

The SCR process starts with injecting a nitrogen-based reagent such as ammonia or urea into the ductwork, downstream of the combustion unit. The exhaust gas mixes with the reagent and enters a reactor module containing catalyst, where it diffuses through the catalyst. The main factors in determining the removal efficiency are: temperature, the amount of reducing agent, injection grid designs, and catalyst activity. Catalyst removal efficiency can be compromised by: poisoning of active sites by flue gas constituents, thermal sintering of active sites to high temperatures within reactor, blinding/plugging/fouling of active sites by ammonia-sulfur salts and particulate matter, and erosion due to high gas velocities.

Since natural gas fired units contain lower levels of NO_X, sulfur, and PM in the exhaust gas, less catalyst will be required, making natural gas fired units with SCR more cost effective. SCR systems can provide up to 90% NO_X removal efficiency. SCR will be considered as a feasible control technology in the top-down RACT analysis for NO_X emissions. The permitted emission limit for these GE PG6541B turbines is 10 ppmvd (4-hr average) @ 15% O_2 for natural gas combustion. Based on BACT/RACT/LAER permitted emission limits and local turbines permitted emission limits, Broadbent will also evaluate SCR at 6.0 ppmvd (4-hr average) NO_X. This limit is offset by a greater degree of Ammonia Slip, to be discussed later in this document.

2.3.7. Technical Feasibility Summary

Table 3 summarizes the results of the technological feasibility evaluations of the identified control options.

Table 3 - NO_X Control Technology Methods for EUs A01 and A02

Control Equipment	Technically Feasible?	Uncontrolled NO_X Emissions (tons/yr)	NO_X Controlled Emission Rate (tons/yr)	NO_X removed (tons/yr)
DLN	Yes	55.17	49.65	5.52
Steam/Water Injection	Yes	baseline	baseline	baseline
SNCR	No	n/a	n/a	n/a

NSCR	No	n/a	n/a	n/a
SCR	Yes	baseline	baseline	baseline
Steam Injection with SCR	Yes	55.17	baseline	baseline
DLN with SCR	Yes	55.17	22.07	33.10

Based on the information presented in Table 2, Saguaro will evaluate a turbine equipped with steam injection and SCR that yields 6 ppm NO_X @ 15% O_2, a turbine retrofitted with DLN combustors that yields 9 ppm NO_X @ 15% O_2, and a turbine retrofitted with DLN combustors and SCR that yields 4 ppm NO_X @ 15% O_2.

2.4 Cost of NO_X Control Options

For each technically feasible method of control, a total annualized equipment cost and an annual operating cost has been calculated. The calculation of the capital cost recovery factor used to estimate the annualized equipment cost assumes an interest rate of 6% and equipment life of 10 years. The individual cost calculations for each control alternative are included in Attachments B-1, B-2, and B-3. The capital cost is based on quotes or estimates from manufacturers. No quote was provided for Dry Low NO_x with SCR, however estimated cost for Dry Low NO_x with SCR was based on telephone conversations with multiple vendors. The calculated costs are summarized in Table 4.

Table 4 - Cost of NO_X Control Options for EUs A01 and A02

Method of Control	Annualized Cost ($/yr)	Estimated NO_X Removal (tons/yr)	Cost Effectiveness ($/ton removed)
Upgraded SCR system rated at 6 ppm NO_X with Steam Injection	$290,040	22.07	$13,143
DLN	$715,347	5.52	$129,662
DLN with SCR rated at 4 ppm NO_X	$790,781	33.10	$23,889

2.5 Environmental, Energy & Economic Considerations

2.5.1. Environmental Impacts

SCR as a control device presents a negative environmental impact due to the released ammonia during its operation. This process is known as Ammonia Slip. Higher NO_X control associated with an SCR system corresponds to higher overall ammonia emissions associated with ammonia slip. An additional environmental impact associated with using SCR comes from ammonia transportation and storage. Ammonia is considered a toxic chemical substance and in the event of spill or fire, presents an enormous environmental liability in the form of air, soil and groundwater contamination, and employee injuries. Any SCR system will incorporate these additional impacts to some extent regardless of final NO_X control efficiency.

2.5.2. Energy Impacts

There are additional power requirements associated with SCR operation due to running the pumps electrical motors associated with the system. However, since the existing baseline operation utilizes SCR, no significant energy impact is associated with implementation of this enhanced technology. No significant energy impacts have been identified for the implementation of DLN technology implementation other than that it would require the power station to be offline for several months in order to reconfigure/overhaul the turbines resulting in a loss of power production for the community during that time period.

2.5.3. Economic Impacts

The economic impacts analysis is based on the cost effectiveness of each technology in terms of the cost per ton of removed pollutant as evaluated in Section 2.4. A maximum cost effectiveness threshold for NO_X RACT has not been established by DES. In 1994, the U.S. EPA recommended a maximum of $1,300 per ton to represent RACT at that time. Based on the increase in the Chemical Engineering Plant Cost Index (CEPCI) between then and now, this equates to approximately $3,000 per ton for the present. The U.S. EPA, in its approval of certain State Implementation Plan revisions for Pennsylvania (85 FR 65706) noted that Pennsylvania's proposed maximum of $2,800 per ton was low compared to other states but approved it. Maximum thresholds for other jurisdictions were presented in the notice as follows:

- Wisconsin, $2,500 per ton NO_X
- Illinois, $2,500—$3,000 per ton NO_X
- Maryland, $3,500—$5,000 per ton NO_X
- Ohio, $5,000 per ton NO_X
- New York, $5,000—$5,500 per ton NO_X

For the purpose of this analysis, even if the maximum value of $5,500 from above is deemed appropriate in Clark County, the cost of control for each individual combustion turbine exceeds this value. Table 4 presents the cost effectiveness of the viable control option upgrades.

3.0 NO_X RACT Determination

After eliminating technically infeasible options, evaluating the remaining technologies for environmental, energy, and economic impacts, and reviewing similar facilities for emission control technologies, Broadbent has determined that SCR and steam injection with a 10.0 ppmvd (4-hr average) NO_X limit at 15 percent oxygen while firing natural gas meets RACT for this application. This limit would not apply during startup, shutdown, or malfunction. Startup and shutdown would amount to the existing 65 lb/hr NO_X emission rate, to be used when CEMs data is not available. Malfunction would amount to use of good combustion practices, to the maximum extent possible during such an event. Monitoring would consist of the existing NO_X CEMs. Recordkeeping and reporting would consist of the following:

- 4-hr rolling averages of exhaust gas concentrations for NO_X and O_2;
- exhaust gas flowrate;
- fuel flowrate;
- hours of operation;
- hourly, daily, and quarterly accumulated mass emissions of NO_X; and

- hours of downtime of NO_X CEMs.

Startup and shutdown events are short in duration for the GE PG6541B turbines. Technically feasible emission controls require full load operation to be implemented, and therefore, cannot be used during startup or guaranteed effective during shutdown. Based on these factors, RACT for startup and shutdown of the GE PG6541B turbines will be work practice standards.

ATTACHMENT B – 1

Cost Effectiveness Calculation

Emission Unit/Control Technology

Emission Unit	A02
Emission Unit Description	Combined Cycle Turbine
Control Technology	Dry Low NOx Configuration
Emission Reduction[1] (%)	10%
Baseline Emission Rate[2] (tons/year)	55.17

Annualized Capital Costs

Initial Capital Investment[3]	$3,793,000
Direct & Indirect Costs[4]	$0
Total Capital Investment	$3,793,000
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$515,347

Annual Operating Costs

Remote Tuning	$200,000
Total Annual Operating Cost	$200,000

Total Annualized Cost	$715,347

Cost Effectiveness

Emissions Reduction (tons/year)	5.52
Cost Effectiveness of NOx Reduction (per	$129,662

Notes:

[1] NO_x emissions reduced from 10 ppm to 9 ppm.

[2] Actual emissions for 2021

[3] Cost based on vendor estimate

[4] Installation, startup and testing accounted for in capital investment.

Wendy Alexander

From: Rob May <rob.may@camsops.com>
Sent: Wednesday, September 21, 2022 1:31 PM
To: Scott McNulty; Wendy Alexander
Subject: FW: GT Controls Upgrade

The email chain below is from a consultant working on similar project and a controls engineer that work on these units DLN-1 is 3.2mil per unit and controls are 593K.

I am waiting for a quote form ethos energy for the same upgrade. (DLN with controls)

SAGUARO POWER COMPANY
Rob May
Plant Manager
702 558 1131
702 300 8181 Cell (NEW)
rob.may@camsops.com
** Note new cell number **

From: Rob May
Sent: Friday, September 9, 2022 6:11 AM
To: archie@arcon-services.com
Subject: RE: GT Controls Upgrade

SAGUARO POWER COMPANY
Rob May
Plant Manager
702 558 1131
702 300 8181 Cell (NEW)
rob.may@camsops.com
** Note new cell number **

From: Archie Conde <archie@arcon-services.com>
Sent: Thursday, September 8, 2022 4:00 PM
To: 'Ron Walker' <ron.walker@controlsystemtechnologies.com>; Rob May <rob.may@camsops.com>
Cc: gkrause@paragonassets.com
Subject: RE: GT Controls Upgrade

Thank Ron. Rob you can add 3.2 million per unit to upgrade to a DLN-1 unit. I base this off the project I am presently working on. Let me know if you need anything further.

From: Ron Walker [mailto:ron.walker@controlsystemtechnologies.com]
Sent: Thursday, September 08, 2022 6:21 PM
To: RobMay
Cc: Archie Conde(archie@arcon-services.com)
Subject: GT ControlsUpgrade

Rob,

I talked with Archie Conde who asked I email you regarding upgrading the GTs control system. We offer a full MkIV GT controls upgrade package to a new and modern system for Water, Steam and DLN-1 type NOx controls. The system hardware is based on a Honeywell C300 controller platform and fully warrantied by Honeywell. CST provides the software algorithms, logic conversions, installation, commissioning and follow-up customer support. Honeywell has it's call-in center for first response customer support where they can access the system and perform analysis on the hardware. If it is determined that the issue is not hardware then a call is made to CST for field engineering support services.

Ballpark for the hardware conversion, control system delivered to site, is approximately $593k. Depending on the existing system options this price could come down or go up, but typically, by not more than 10%.

I hope this helps you, if not, please feel free to reach out to me for any additional questions you or your team might have.

Sincerely,
Ron

Ronald Walker

Visit us at: www.cstfs.com

1969South Alafaya Trail, Suite 111
Orlando, FL32828

O: 321.418.8003
C:407.948.2183
F: 877.530.8717

ATTACHMENT B – 2

Cost Effectiveness Calculation

Emission Unit/Control Technology

Emission Unit	A02
Emission Unit Description	Combined Cycle Turbine
Control Technology	DLN with SCR
Emission Reduction[1] (%)	60%
Baseline Emission Rate[2] (tons/year)	55.17

Annualized Capital Costs

Initial Capital Investment[3]	$4,293,000
Direct & Indirect Costs[4]	$0
Total Capital Investment	$4,293,000
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$583,281

Annual Operating Costs

Ammonia Cost	$207,500
Total Annual Operating Cost	$207,500

Total Annualized Cost	$790,781

Cost Effectiveness

Emissions Reduction (tons/year)	33.10
Cost Effectiveness of NOx Reduction (per	$23,889

Notes:

[1] NO_x emissions reduced from 10 ppm to 4 ppm.

[2] Actual emissions for 2021

[3] Cost based on vendor estimate for DLN and estimate for DLN-compatible SCR

[4] Installation, startup and testing accounted for in capital investment

ATTACHMENT B - 3

Cost Effectiveness Calculation

Emission Unit/Control Technology

Emission Unit	A02
Emission Unit Description	Combined Cycle Turbine
Control Technology	Upgraded SCR with steam injection
Emission Reduction[1] (%)	40%
Baseline Emission Rate[2] (tons/year)	55.17

Annualized Capital Costs

Initial Capital Investment[3]	$607,500
Direct & Indirect Costs[4]	$0
Total Capital Investment	$607,500
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$82,540

Annual Operating Costs

Ammonia Cost	$207,500
Total Annual Operating Cost	$207,500
Total Annualized Cost	$290,040

Cost Effectiveness

Emissions Reduction (tons/year)	22.07
Cost Effectiveness of NOx Reduction (per	$13,143

Notes:

[1] NO_x emissions reduced from 10 ppm to 6 ppm.

[2] Actual emissions for 2021

[3] Cost based on vendor estimate

[4] Installation, startup and testing accounted for in capital investment.

Wendy Alexander

From: Balasubramanian, Vignesh <vbala@vogtpower.com>
Sent: Friday, September 30, 2022 6:58 AM
To: Wendy Alexander
Cc: Stull, Michael; Scott McNulty
Subject: RE: SCR catalyst replacement for combined cycle turbine

Hi Wendy – Pleasure speaking with you yesterday.

Here is my preliminary estimate of the cost of the replacement catalyst:

1. Engineering, including thermal analysis to ensure catalyst temperatures are appropriate - $40,000 total
2. Quality / Project Management - $25,000 total
3. Catalyst - $300,000 per unit, $600,000 total
4. Installation - $550,000 total
5. Total price for 2 units - $1,215,000

This is a +-30% estimate with the information provided. During detailed execution, we can provide a firm price based on catalyst operating temperatures etc.

Thanks.

Sincerely,

Vignesh Bala
Director of Operations - HRSG Services

VOGT POWER INTERNATIONAL
A Babcock Power Inc. Company
13400 Eastpoint Centre Dr. Suite 200 | Louisville, KY 40223

office | (502) 271 0526
email | vbala@vogtpower.com
web | https://www.babcockpower.com/vogt

From: Wendy Alexander <walexander@broadbentinc.com>
Sent: Wednesday, September 28, 2022 6:00 PM
To: Balasubramanian, Vignesh <vbala@vogtpower.com>; Ryan Jeter <rjeter@miratechcorp.com>
Cc: Stull, Michael <mstull@vogtpower.com>; Scott McNulty <smcnulty@broadbentinc.com>
Subject: RE: SCR catalyst replacement for combined cycle turbine

Vignesh,

Appendix C

RACT Analysis - Volcano Boiler, Emission Unit A05

APPENDIX C

RACT Analysis

Volcano Boiler, Emission Unit A05

Appendix C
Table of Contents

1.0 General

This appendix summarizes the Reasonably Available Control Technology (RACT) Analysis performed for the Volcano Boiler, Emission Unit (EU) A05, located at Saguaro Power Company (Saguaro). The basic steps for this analysis are as follows:

- Identification of existing equipment and baseline emissions
- Identification of available control technologies.
- Elimination of technically infeasible control options.
- Determination of the cost effectiveness of control options
- Evaluation of the benefits and disadvantages (environmental, energy and economic) associated with the technically feasible control options
- Identification of RACT control technology including emission limitations, monitoring, testing, recordkeeping and reporting requirements.

Controls for oxides of nitrogen (NO_X) are evaluated in this appendix.

2.0 NO_X RACT Assessment

2.1 Equipment Description and Limitations

EU A05 is a boiler with a maximum heat input rating of 218 MMBtu/hr which utilizes natural gas and/or hydrogen as the fuel supply. The emission unit is limited to 1,909,680 MMBtu annually. Further, NO_x emissions are limited to 12 ppmvd (4-hr average) @ 3% O_2. Finally, CO emissions are limited to 1.2 ppmvd (24-hr average) @3% O_2, as part of a Lowest Achievable Emission Rate (LAER) determination and thus cannot be increased as part of a NO_x control upgrade. It should be noted that NO_x and CO are inversely proportional in most combustion-based control upgrades meaning that decreasing NO_x emissions would result in increased CO emissions.

2.2 Baseline Emissions

As noted in Section 3 of the report, baseline emissions can be set equivalent to actual emissions if actual emissions for the three previous consecutive years are 70% or less of the source's potential emissions. Saguaro meets this criterion on a facility-wide basis.

Table 1 summarizes the baseline NO_x emissions for EU A05., which is equipped with a low NO_x burner and Flue Gas Recirculation (FGR) as NO_x controls.

Table 1 - Baseline Emissions

Emission Unit	NO_x Emissions[1] (tons)
A05	0.40

Notes: [1] Maximum annual emissions from 2019 - 2021

2.3 Identification and Technical Feasibility of NO_x Control Options

2.3.1. Identification of Available Controls

A review of RACT determinations for boilers over the last five years was conducted by reviewing the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC). The database did not contain any RACT determinations for this time period for comparably sized units. In addition, various U.S. EPA control technology reports were reviewed and the current contractor responsible for servicing Saguaro's boilers was consulted to identify potential controls. Based on the information obtained, the proposed NO_x control technologies for EU A05 are summarized in Table 2.

Table 2 - Available NO_x Control Technology Methods for EU A05

Control Equipment	NO_X PPM Guarantee or Reduction Potential (%)	Range of Application	Commercial Availability/ R&D Status
Low NO_x Burners	9 ppm NO_x	Wide range of application	Commercially available
Flue Gas Recirculation (FGR)	30-60	Wide range of application, Baseline for this application	Commercially available
Selective Catalytic Reduction (SCR)	75-90	Limited range of applications	Commercially available
Selective Non Catalytic Reduction (SNCR)	75 – 90	Limited range of applications	Commercially available, but not widely used
Low NO_x Burners with FGR	12 ppm NO_x	Baseline for this application	Commercially available with certain boilers. Baseline for this application

Since NO_X and CO emissions are inversely proportional and CO emissions are limited to 1.2 ppmvd (24-hr average) @3% O_2, as part of a Lowest Achievable Emission Rate (LAER) determination, CO emissions need to be considered when evaluating RACT for NO_x. NO_x controls that would result in CO emission increases would violate the LAER determination and thus will not be considered feasible.

The technical feasibility of each control option will next be evaluated.

2.3.2. Low NO_X burner rated at 9 ppm corrected to 3% oxygen

Burner modifications for NO_X control involve changing the design of a standard burner in order to create a larger flame. Enlarging the flame results in lower flame temperatures and lower thermal NO_X formation which, in turn, results in lower overall NO_X emissions.

Low NO_X burners reduce NO_X by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame, which suppresses thermal NO_X formation. The two most common types of low NO_X burners being applied to natural gas boilers are staged air burners and staged fuel burners, or a combination thereof.

The current burner assembly could be replaced with a model that is guaranteed to meet a 9 ppm NO_x emission rate, but with a 15 ppm CO emission rate. No suppliers contacted could reduce NO_x without a corresponding increase in CO emissions above the 1.2 ppm LAER limitation. Therefore, replacing the burner with a lower NO_x rated assembly is not considered technically feasible.

2.3.3. Flue Gas Recirculation (FGR)

FGR involves the recirculation of a portion of the flue gas to the burners. It reduces NO_x emissions by two mechanisms. First, the recirculated gas acts as a dilutant to reduce combustion temperatures, thus suppressing the thermal NO_x mechanism. Second, FGR lowers the oxygen concentration in the primary flame zone. The portion recycled is up to 25% to 30% and it can be implemented on most new design types. An FGR system is normally used in combination with specially designed low NO_x burners capable of sustaining a stable flame with the increased inert gas flow resulting from the use of FGR. It may not be feasible on all existing boiler types or in places with spacing limitations. In this case, it is viable along with a 12 ppm NO_x burner.

2.3.4. Selective Catalytic Reduction (SCR)

SCR involves the injection of ammonia in the boiler exhaust gases in the presence of a catalyst. The catalyst allows the ammonia to reduce NO_X levels at lower exhaust temperatures than selective non-catalytic reduction (SNCR). Unlike SNCR, where the exhaust gases must be approximately 1400-1600°F, SCR can be utilized where exhaust gases are between 500° and 1200°F, depending on the catalyst used. SCR can result in NO_X reductions up to 75%. Since the EU A05 boiler generates exhaust temperatures of around 325 ° F, an SCR system is not a technically feasible option for this application.

2.3.5. Selective Non-Catalytic Reduction (SNCR)

SNCR involves the injection of a NO_X reducing agent, such as ammonia or urea, in the boiler exhaust gases at a temperature of approximately 1400-1600°F. The ammonia or urea breaks down the NO_X in the exhaust gases into water and atmospheric nitrogen. SNCR reduces NO_X up to 50%. As was the case with SCR control, the boiler exhaust temperature is far too low to implement SNCR as a viable control technology. The 325° F boiler exhaust makes an SNCR system not technically feasible for this application.

2.3.6. Technological Feasibility Summary

Table 3 summarizes the technological feasibility evaluations of the identified control options.

Table 3 - NO_x Control Technology Methods for EU A05

Control Equipment	Technically Feasible?	Uncontrolled NO_X Emissions (tons/yr)	NO_X Controlled Emission Rate (tons/yr)	NO_X removed (tons/yr)
Low NO_X burner rated at 9 ppm	No	n/a	n/a	n/a
Low NO_x burner rated at 12 ppm with FGR	Yes	Baseline	Baseline	Baseline
SCR	No	n/a	n/a	n/a
SNCR	No	n/a	n/a	n/a

Based on the information presented in Table 3, the only technically viable option is the baseline case.

2.4 Cost of NO_X Control Options

For each technically feasible method of control alternative, a total equipment cost and an annual operating cost is typically calculated. In this case, the only technically feasible option is what is already installed so no costs are associated with it.

Table 4 - Cost ff NO_x Control Options for EU A05

Method of Control	Capital Cost	Annualized Cost ($/yr)	Estimated NO_X Removal (tons/yr)	Cost Effectiveness ($/ton removed)
NO_X burner rated to 12 ppm with FGR	$0	$0	0.00	n/a

2.5 Environmental, Energy & Economic Considerations

There are no environmental, energy, or economic impacts associated with this analysis.

3.0 NO_x RACT Determination

After eliminating technically infeasible options, it is evident that boiler EU A05 can be considered to comply with RACT with the existing 12 ppm burner with FGR as a lower NO_x burner is not technically feasible based on the CO LAER limit. Performance tests and CEMS data for the existing boiler emissions indicate the current NO_x emission limit is achieved.

The 12 ppm @3% O_2 (4-hr average) NO_x limit would not apply during periods of startup, shutdown, or malfunction. Instead, the boiler would be subject to good combustion practices, to the maximum extent possible during such events. Monitoring would consist of the existing NO_x CEMs. Recordkeeping and reporting would consist of the following:

- 4-hr rolling averages of exhaust gas concentrations for NO_x and O_2;

- exhaust gas flowrate;
- fuel flowrate;
- hours of operation;
- hourly, daily, and quarterly accumulated mass emissions of NO_x; and
- hours of downtime of NO_x CEMs

Appendix D

RACT Analysis - Nationwide/Nebraska Boiler, Emission Unit A06

APPENDIX D

RACT Analysis

Nationwide/Nebraska Boiler, Emission Unit A06

Appendix D
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Attachments

1.0 General

This appendix summarizes the Reasonably Available Control Technology (RACT) Analysis performed for the Nationwide/Nebraska Boiler, Emission Unit (EU) A06, located at Saguaro Power Company (Saguaro). The basic steps for this analysis are as follows:

- Identification of existing equipment and baseline emissions
- Identification of available control options
- Elimination of technically infeasible control options
- Determination of the cost effectiveness of control options
- Evaluation of the benefits and disadvantages (environmental, energy and economic) associated with the technically feasible control options
- Identification of RACT control technology including emission limitations, monitoring, testing, recordkeeping and reporting requirements

Controls for oxides of nitrogen (NO_X) are evaluated in this appendix.

2.0 NO_X RACT Assessment

2.1 Equipment Description and Limitations

EU A06 is a Nebraska boiler with a maximum heat input rating of 86 MMBtu/hr that utilizes natural gas as the fuel supply. The emission unit is limited to 510,000 MMBtu annually. Further, NO_x emissions are limited to 30 ppmvd (4-hr average) @ 3% O_2.

2.2 Baseline Emissions

As noted in Section 3 of the report, baseline emissions can be set equivalent to actual emissions if actual emissions for the three previous consecutive years are 70% or less of the source's potential emissions. Saguaro meets this criterion on a facility-wide basis.

Table 1 summarizes the baseline NO_x emissions for EU A06, which is equipped with a low NO_x burner for NO_x control.

Table 1 - Baseline Emissions

Emission Unit	NO_x Emissions[1] (tons)
A06	0.72

Notes: [1] Maximum annual emissions from 2019 - 2021

2.3 Identification and Technical Feasibility of NO_x Control Options

2.3.1. Identification of Available Controls

A review of the most recent (5 years) determinations contained in the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC) was conducted to identify any recent RACT determinations for boilers of the same or comparable size. The database did not contain any RACT determinations for this time period. In addition, various U.S. EPA control technology reports were reviewed and the current contractor responsible for servicing Saguaro's boilers was consulted to identify potential controls. Based on the information obtained, the proposed NO_x control technologies for EU A06 are summarized in Table 2.

Table 2 - Available NO_x Control Technology Methods for EU A06

Control Equipment	NO_X PPM Guarantee or Reduction Potential (%)	Range of Application	Commercial Availability/ R&D Status
Low NO_x Burners with Flue Gas Recirculation (FGR)	30-70 (20 ppm NO_x or 9 ppm NO_x)	Burner changeout is normally an option for any boiler, FGR requires physical space around the boiler that is not always available	Commercially available with certain boilers
Flue Gas Recirculation (FGR)	30-60	Sometimes combined with Low NO_x Burners	Commercially available
Selective Catalytic Reduction (SCR)	75-90	Limited range of application and normally not with boiler exhaust profiles	Available
Selective Non-Catalytic Reduction (SNCR)	75-90	Limited range of application and normally not with boiler exhaust profiles	Commercially available, but not widely used

The technical feasibility of each control option will next be evaluated.

2.3.2. NO_X burner rated at 20 ppm or 9 ppm corrected to 3% oxygen with FGR

Burner modifications for NO_X control involve changing the design of a standard burner in order to create a larger flame. Enlarging the flame results in lower flame temperatures and lower thermal NO_X formation which, in turn, results in lower overall NO_X emissions.

Low NO_X burners reduce NO_X by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame, which suppresses thermal NO_X formation. The two most common types of low NO_X burners being applied to natural gas boilers are staged air burners and staged fuel burners, or a combination thereof. The existing burner associated with this boiler is a low NO_x burner designed to achieve 30 ppm NO_x corrected to 3% oxygen. It cannot be modified to achieve a lower NO_x concentration so it would be necessary to replace it with a lower NO_x burner. This is technically feasible and would be capable of reducing the NO_x concentration in the boiler exhaust to either 20 ppm or 9 ppm corrected to 3% oxygen depending on the burner design. Emissions of CO would necessarily increase; however, they should not exceed the current 400 ppm CO limit. To achieve these NO_x ppm ratings, the boilers would also need to be modified to include FGR. This technology is discussed separately below.

2.3.3. Flue Gas Recirculation (FGR)

FGR involves the recirculation of a portion of the flue gas to the burners. It reduces NO_x emissions by two mechanisms. First, the recirculated gas acts as a dilutant to reduce combustion temperatures, thus suppressing the thermal NO_x mechanism. Second, FGR lowers the oxygen concentration in the primary flame zone. The portion recycled is up to 25% to 30% and it can be implemented on most new design types. An FGR system is normally used in combination with specially designed low NO_x burners capable of sustaining a stable flame with the increased inert gas flow resulting from the use of FGR. It may not be feasible on all existing boiler types or in places with spacing limitations. For the Nebraska boiler, it has been determined that FGR could be installed and coupled with burners to provide a 20 ppm or a 9 ppm NO_x guarantee.

2.3.4. SCR

SCR involves the injection of ammonia in the boiler exhaust gases in the presence of a catalyst. The catalyst allows the ammonia to reduce NO_X levels at lower exhaust temperatures than selective non-catalytic reduction (SNCR). Unlike SNCR, where the exhaust gases must be approximately 1400-1600°F, SCR can be utilized where exhaust gases are between 500° and 1200°F, depending on the catalyst used. SCR can result in NO_X reductions up to 75%. Since EU A06 generates exhaust temperatures around 325 ° F, an SCR system is not a technically feasible option for this application.

2.3.5. SNCR

SNCR involves the injection of a NO_X reducing agent, such as ammonia or urea, in the boiler exhaust gases at a temperature of approximately 1400-1600°F. The ammonia or urea breaks down the NO_X in the exhaust gases into water and atmospheric nitrogen. SNCR reduces NO_X up to 50%. As was the case with SCR control, the boiler exhaust temperature is far too low to implement SNCR as a viable control technology. The 325 ° F boiler exhaust makes an SNCR system not technically feasible for this application.

2.3.6. Technical Feasibility Summary

Table 3 summarizes the technological feasibility evaluations of the identified control options.

Table 3 - NO_x Control Technology Methods for EU A06

Control Equipment	Technically Feasible?	Uncontrolled NO_X Emissions (tons/yr)	NO_X Controlled Emission Rate (tons/yr)	NO_X removed (tons/yr)
NO_X burner rated at 9 ppm with FGR	Yes	0.72	0.22	0.50

NO_x burner rated at 20 ppm with FGR	Yes	0.72	0.48	0.24
SCR	No	n/a	n/a	n/a
SNCR	No	n/a	n/a	n/a

Based on the information presented in Table 3, Saguaro will evaluate the cost of a NO_x burner rated at 20 ppm combined with FGR and a NO_X burner rated at 9 ppm combined with FGR. Since 30 ppm NO_x is baseline, cost is not evaluated for it.

2.4 Cost of NO_X Control Options

For each technically feasible method of control, a total annualized equipment cost and an annual operating cost has been calculated. The calculation of the capital cost recovery factor used to estimate the annualized equipment cost assumes an interest rate of 6% and equipment life of 10 years. The individual cost calculations for each control alternative are included in Attachments D-1 and D-2. The capital cost is based on quotes or estimates from manufacturers. In this case, quotes from R.F. MacDonald Company that services the Saguaro boilers. The calculated costs are summarized in Table 4.

Table 4 Cost Of NO_x Control Options for EU A06

Method of Control	Annualized Cost ($/yr)	Estimated NO_X Removal (tons/yr)	Cost Effectiveness ($/ton removed)
NO_X burner rated to 9 ppm with FGR	$89,351	0.50	$177,283
NO_x burner rated to 20 ppm with FGR	$75,764	0.24	$315,683

2.5 Environmental, Energy & Economic Considerations

2.5.1. Environmental Impacts

No additional environmental impacts were identified with implementation of the replacement burners and FGR. Actual emissions of CO would probably increase as part of this conversion; however, they should not increase above the permitted limits for CO on the boiler.

2.5.2. Energy Impacts

It is anticipated that only minimal adverse energy impacts would be associated with a lower NO_x burner or FGR technology since there would be minimal decrease in burner efficiency.

2.5.3. Economic Impacts

The economic impacts analysis is based on the cost effectiveness of each technology in terms of the cost per ton of removed pollutant as evaluated in Section 2.4. A maximum cost effectiveness threshold for NO_x RACT has not been established by DES. In 1994, the U.S. EPA recommended a maximum of $1,300 per ton to represent RACT at that time. Based on the increase in the Chemical Engineering Plant Cost Index (CEPCI) between then and now, this equates to approximately $3,000 per ton for the present. The U.S. EPA, in its approval of certain State Implementation Plan revisions for Pennsylvania (85 FR 65706) noted that Pennsylvania's proposed maximum of $2,800 per ton was low compared to other states but approved it. Maximum thresholds for other jurisdictions were presented in the notice as follows:

- Wisconsin, $2,500 per ton NO_X
- Illinois, $2,500—$3,000 per ton NO_x
- Maryland, $3,500—$5,000 per ton NO_X
- Ohio, $5,000 per ton NO_X
- New York, $5,000—$5,500 per ton NO_X

For the purpose of this analysis, even if the maximum value of $5,500 from above is deemed appropriate in Clark County, the cost of control for boiler EU A06 significantly exceeds this value. Table 4 presents the cost effectiveness of the viable control option upgrades and a 9-ppm burner with FGR would exceed $177,000 per ton to implement. It should be noted that although there are no plans to operate this boiler at or near it's permitted Potential to Emit (PTE), even if it were and that emissions savings was input in the analysis, the cost would still exceed $10,000 per ton of NO_x removed.

3.0 NO_x RACT Determination

After eliminating technically infeasible options, evaluating the remaining technologies for environmental, energy, and economic impacts, it is evident that boiler EU A06 can be considered to comply with RACT with the existing low NO_x burner with a 30.0 ppm (4-hr average) NO_x limit at 3 percent oxygen while firing natural gas. Performance tests indicate the current emission limit is achieved.

The 30 ppm @3% O_2 (4-hr average) NO_x limit would not apply during periods of startup, shutdown, or malfunction. Instead, the boiler would be subject to good combustion practices, to the maximum extent possible during such events. Monitoring would consist of the semiannual burner efficiency tests along with performance testing every 5 years. Recordkeeping and reporting would consist of the burner efficiency test results and the report for the performance testing.

ATTACHMENT D-1

Cost Effectiveness Calculation

Emission Unit/Control Technology

Emission Unit	A06
Emission Unit Description	Nationwide/Nebraska Boiler
Control Technology	Low NO_x Burner with FGR
Emission Reduction[1] (%)	70%
Baseline Emission Rate[2] (tons/year)	0.72

Annualized Capital Costs

Initial Capital Investment[3]	$657,629
Direct & Indirect Costs[4]	$0
Total Capital Investment	$657,629
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$89,351

Annual Operating Costs

Total Annual Operating Cost	$0
Total Annualized Cost	$89,351

Cost Effectiveness

Emissions Reduction (tons/year)	0.50
Cost Effectiveness of NOx Reduction (per	$177,283

Notes:

[1] NO_x emissions reduced from 30 ppm to 9 ppm.

[2] Actual emissions for 2020 (max of 2019 - 2021).

[3] Cost based on vendor estimate.

[4] Installation, startup and testing (accounted for in vendor estimate).

CleaverBrooks®

Budget Proposal

Saguaro Power Burner Retrofit

To: Scott Mcnulty
Principal Geologist
Broadbent Air Quality Division
8 W Pacific Ave,
Henderson, NV 89015 United States
(702) 563-0600
Smcnulty@broadbentinc.com

From: Ryland Whitaker
R.F. MacDonald Company
6651 Schuster Street

Las Vegas, NV 89118 United States
(725)229-3368
ryland.whitaker@rfmacdonald.com

September 28, 2022

Dear Scott,

Through a steadfast commitment to research, development, strategic acquisitions, and a focus on providing boiler room solutions for more than 80 years, Cleaver-Brooks is the sole provider of integrated boiler, burner, and controls solutions. With the #1 market share in North America, Cleaver-Brooks is the global leader in designing and manufacturing integrated boiler room systems, and the Cleaver-Brooks brand is globally synonymous with the highest quality, best reliability, and creative innovation in boiler room solutions. Industry-leading proprietary burners, controls, components, and accessories engineered by Cleaver-Brooks perform together seamlessly at peak energy and emissions efficiency.

Cleaver-Brooks offers the broadest range of integrated boiler room systems, subsystems, components and accessories in the market, giving it a distinct competitive advantage as a complete solutions provider across commercial, industrial, and institutional markets. A principal component of the Cleaver-Brooks strategy is to offer the most advanced and completely integrated boiler room systems that satisfy diverse energy demands, high-efficiency performance, ultra-low emissions, safety, reliability, and convenience from utilizing a single-source manufacturer.

From the Power of Total Integration, Cleaver-Brooks offers boiler room systems including mission-critical subsystems performing water treatment, heat recovery, integrated system controls, and maintained by a worldwide dedicated sales and service representative network. All sales and service representatives employ trained technicians to provide first-class routine maintenance and repair services in accordance with national, state/provincial, and local codes and standards.

As a Cleaver-Brooks Representative Association (CBRA) member near you, R.F. MacDonald Company has produced this proposal from your system requirements and equipment specifications. At your convenience, please review this proposal, and contact me regarding any questions or comments.

Sincerely,

Ryland Whitaker
R.F. MacDonald Company
6651 Schuster Street
Las Vegas, NV 89118 United States
(725)229-3368
ryland.whitaker@rfmacdonald.com

Configurable Burner

NCB Burner System

- For new boilers or retrofit applications/hr
- Natural Gas and light oil firing/hr
- Millions of configurations possible to satisfy your specific needs
- Available to < 30 ppm NOx, < 50 ppm CO
- 12 to 360 MMBTU/hr

The NCB burner is a unique packaged burner system for new boilers and retrofit markets. These burners use advanced CFD modeling, and are equipped with advanced Natcom® design features, including externally adjustable gas injectors, Class-III igniters, atomizers with coupling block valves, which you can complement with your choice among a variety of industrial-grade controls, valves, switches, and gauges.

Natcom® burners feature emissions reductions of 50% compared to flaring and can achieve emissions goals of 9 ppm NOx. The high-efficiency burner design is engineered for multi-fuel firing, including renewables.

NCB-085 Burner

Technical Data Sheet

For indoor applications, uncontrolled or 30 ppm NOx emissions

85 MM BTU/H NG; 81 MM BTU/H #2 OIL

Designed for furnace dimensions of at least:	Physical arrangement:	Combustion Control System (CCS) compatibility options:	Fuel Options:	Choice of NFPA or CSA compliance for U.S. or Canadian units, respectively (contact us for TSSA compliance).
H=8.97' W=6.69' Lturn=15.33' Ltot=18.00'	FD fan, fuel train and control panel are windbox mounted. Right- or left-hand drum arrangements available.	Fully Metered (FM), Parallel Positioning (PP) and Single Point Positioning (SP). All systems use 4-20mA and pneumatic actuators.	Main Fuel: Natural gas and/or #2 oil. Igniter fuel: Natural gas and/or propane.	

Performance guarantees

	NG, no FGR	#2 Oil, no FGR	NG, 12% FGR	#2 Oil, 12% FGR
Excess Air %*	15	15	15	15
NOx emissions ppmvd @3%O_2	70	110	30	75
CO emissions ppmvd @3%O_2	50	75	50	75
VOC lb/MM BTU (HHV)	0.004	0.004	0.004	0.004
Total PM lb/MM BTU (HHV)	0.01	0.05	0.01	0.05
Turndown	10	8	10	8

Performance guarantees are based on normal operating conditions and valid from 25% to 100% MCR, boiler with gas tight furnace division wall and to nominal operating pressure and temperature. Igniter emissions are not guaranteed. For application where CB does not provide the controls, emissions are guaranteed in manual mode only. SOx emissions are not burner dependent and depend solely on the sulfur content of the fuel. Burner/boiler systems are not intended for automatic recycling use. Fan motors of 100 HP and above are only offered with manual start/stop control. Please contact your local representative for more details.

*Excess air given for MCR only.

CleaverBrooks®

Budget Quote Summary

Proposal Number: 29850248 / Proposal Date: 09/16/22

Job Name: Saguaro Power Burner Retrofit / Project Name: Saguaro Power Burner Retrofit

Product Model: NATCOM		
Item	**Qty.**	**Description**
#1	1	**Reference: 1** Configured in the Custom NATCOM program.
#2	1	Burner Model: NCB-230
#3	1	Fuels Included: Gas
#4	1	Burner Heat Input (MMBTU/hr): 85
#5	1	Guaranteed NOx Emissions, Gas (PPM @3% O2): 30
#6	1	Type of Control: Full Metering
#7	1	Burner Fan Motor HP: 150
#8	1	Burner Fan Location: Windbox Mounted
#9	1	Available Gas Pressure at Regulator Inlet: 25 - 40 psig
#10	1	Oil Pressure Required @ Train Inlet: 150 psig
#11	1	Turndown on Natural Gas: 10:1
#12	1	Turndown Firing Oil: 8:1
#13	1	Variable Frequency Drive Included: Y
#14	1	O2 Trims: Yes
#15	1	Boiler Control Model: HAWK 4500
#16	1	Ambient Temperature Range: 50 - 100 °F
#17	1	Site Elevation: < 2500 ft ASL
		Product Price to Customer (USD): $

CleaverBrooks

Budget Quote Summary

Proposal Number: 29850248 / Proposal Date: 09/16/22

Job Name: Saguaro Power Burner Retrofit / Project Name: Saguaro Power Burner Retrofit

Item	Qty.	Product Model	PTC (USD)
#1	1	NATCOM	$507.629.00
		Subtotal Price to Customer (USD):	$507,629.00
		Cost Adder for 9ppm(USD):	$150,000.00
		Freight (EXW - Ex Works Factory) Cost (USD):	NA
		Total Price to Customer (USD):	$657,629.00

CLEAVER-BROOKS OFFERING

Cleaver-Brooks offers to furnish the Equipment described herein for the purchase price noted, exclusive of all taxes. Prices quoted are firm for 30 days from the date of the Cleaver-Brooks Proposal subject to adjustment as noted. Standard Cleaver-Brooks **payment terms** are *unconditional net 30 from the date of readiness for shipment or unless otherwise specified in this Proposal*. Cleaver-Brooks will review your order prior to acceptance (and acknowledgment) and order entry. Until acceptance and order entry, the Equipment is **subject to prior sale**. Incorporation of technical specifications or requirements different from or additional to the Cleaver-Brooks Proposal and not previously reviewed by Cleaver-Brooks will extend the order review process and may postpone or prevent acceptance of your order and order entry. Cleaver-Brooks does not agree and will not agree to **INCIDENTAL, CONSEQUENTIAL AND LIQUIDATED DAMAGES OR IMPLIED WARRANTIES**. Cleaver-Brooks does not agree and will not agree to, unless specifically set forth in an agreement in writing having an authorized Cleaver-Brooks signature: (1) **terms and conditions** in your order that are different from or additional to those of the Cleaver-Brooks Proposal; (2) **technical specifications**, technical requirements or descriptions of the goods and services ordered that are different from or additional to those of the Cleaver-Brooks Proposal; or (3) **generalized expressions** such as "per plans and specifications."

CLEAVER-BROOKS PRICE ADJUSTMENT POLICY

The price quoted in the Cleaver-Brooks Proposal is firm for thirty (30) days from the Proposal date if shipment of the Equipment is made within six (6) months from the date of the Cleaver-Brooks Proposal or contract document if no Proposal was issued. If the Equipment is not shipped within such six (6) months, the contract price shall be increased by one percent (1%) for each thirty (30) days or fraction thereof that shipment is deferred beyond six (6) months from the date of the Cleaver-Brooks Proposal or contract document.

PROPOSED PAYMENT TERMS

Amount At or Exceeds $250,000: Yes
Payment Terms: Progress Payments
Terms Description:

Note: May require Cleaver-Brooks review if other than 20%/30%/50% referenced in ¶ 1(a).

PROPOSED SHIPPING TERMS

[x] EXW – Ex Works Factory
[ ] CIP – Carriage and Insurance Paid to
[ ] OTHER:____
Freight Allowed To Location:________________________________

Note: Freight unloading by others.

BUYER OF CLEAVER-BROOKS EQUIPMENT

Buyer Representative - Printed First and Last Name

Buyer Representative - Company Name

,

Buyer Representative - Company Address, State/Province, Area Code, and Country

Buyer Representative - Phone Number

Buyer Representative - Email Address

Buyer Representative - Signature

/ /

Buyer Representative - Date Accepted (MM/DD/YYYY)

CLEAVER-BROOKS SALES REPRESENTATIVE

Ryland Whitaker

Sales Representative - Printed First and Last Name

R.F. MacDonald Company

Sales Representative - Company Name

10261 MATERN PLACE
SANTA FE SPRINGS, CA 90670
United States

Sales Representative - Company Address, State/Province, Area Code, and Country

(725)229-3368

Sales Representative - Phone Number

ryland.whitaker@rfmacdonald.com

Sales Representative - Email Address

Sales Representative - Signature

09/16/22

Sales Representative - Date Offered

CLEAVER-BROOKS TERMS AND CONDITIONS OF SALE ON NEXT PAGE

THE CLEAVER-BROOKS COMPANY, INC. GENERAL TERMS AND CONDITIONS OF SALE

1. OFFER AND CONTRACT

(a) Through its proposal (the "Proposal") The Cleaver-Brooks Company, Inc. (the "Company") offers to sell its products, systems or parts (the "Equipment") for the purchase price (the "Purchase Price") on these terms and conditions of sale.

(b) UPON WRITTEN ACCEPTANCE OF THE PROPOSAL BY THE BUYER, THE PROPOSAL AND THESE TERMS CONSTITUTE THE COMPLETE AGREEMENT BETWEEN THE COMPANY AND THE BUYER ("THIS AGREEMENT"). ANY ADDITIONAL OR DIFFERENT TERMS ARE REJECTED UNLESS AGREED TO BY THE COMPANY IN A SIGNED AMENDMENT AFTER REVIEW AT THE PRODUCT GROUP HOME OFFICE.

(c) Except as indicated below, this **Proposal is valid for thirty (30) days** subject to written withdrawal by the Company at any time prior to receipt of written acceptance by the Buyer.

(d) The Purchase Price and any delivery dates of this Proposal are **subject to prior sales that occur before written acceptance by the Buyer and increased material costs**.

(e) Orders received are scheduled for production as proposals are accepted in writing by the Buyer.

(f) If at the time the Product Group home office receives a written acceptance of a proposal, and the then available production lead time at the Product Group manufacturing location does not allow for shipment within the number of weeks offered in the Proposal, then the Purchase Price and any delivery dates shall be adjusted based upon the next available production and delivery dates.

2. TERMS AND PRICES

(a) Standard terms of payment are thirty (30) days net from the date of invoice for completion of performance milestones for payment, including readiness of the Equipment for shipment. Partial shipments of units under multiple unit orders shall be invoiced and paid separately. The Company will waive lien rights and release payment claims to the extent of payments received. The Company may require a letter of credit from the Buyer.

(b) Any excise, sales, privilege, use or any other local, state, or federal taxes which the Company may be required to pay, arising from the sale, delivery, or use of the Equipment and any applicable prepaid freight, will be added to the Purchase Price and invoiced separately.

(c) If the Buyer requests changes in scope or schedule, or if the Buyer delays production or shipment of the Equipment, the Purchase Price and any delivery dates shall be equitably adjusted to reflect changes caused thereby.

(d) Availability and costs of any proposed surety bonding (or other financial securities) are determined by providers thereof at the time of award and the costs of such surety bonding shall be added to the Purchase Price. The Company does not commit to provide a particular financial security. All financial securities issued will be subject to agreed expiration dates, and reduce in amount as performance milestones are accomplished.

(e) The Buyer shall pay **interest on all late payments** at the lesser rate of 1.5% per month or the highest rate permissible under applicable law, calculated daily and compounded monthly.

(f) The Buyer shall reimburse the Company for all costs incurred in collecting any late payments, including, without limitation, attorney's fees.

(g) The Buyer shall not withhold payment of any amounts due and payable by reason of any set-off of any claim or dispute with the Company, whether relating to the Company's breach, bankruptcy, or otherwise. The Company shall not be liable for any claim by the Buyer unless and until such claim is finally adjudicated through the dispute resolution process.

(h) The Purchase Price is subject to increase before written acceptance of the Proposal by the Buyer based upon an increase of the CRU USA Midwest FOB Mill index.

(i) In addition to all other remedies available under this Agreement or at law (which the Company does not waive by the exercise of any rights hereunder), the Company shall be entitled to suspend the manufacture and/or delivery of any Equipment if the Buyer fails to pay any Company invoice within thirty (30) days of the date of the invoice.

3. DELIVERY

(a) Unless otherwise offered in this Proposal, delivery is Ex Works (INCOTERMS® (most recent version)), at the Product Group manufacturing location ("the Delivery Point").

(b) The estimated shipment date is based upon timely receipt by the Company of **Buyer's applicable information**, and of **Buyer's written approval**, or detailed exceptions to, the Company's general arrangement drawings within ten (10) business days of receipt.

(c) If the **Buyer requests to defer delivery** dates by a written request adequate to support GAAP requirements for revenue recognition by the Company, or if the Buyer fails to promptly accept the Equipment tendered for delivery, or shipment of the Equipment is otherwise delayed by causes beyond the Company's reasonable control, the following conditions shall apply: (i) payments due upon shipment (or "delivery") shall be invoiced, due and payable upon "readiness to ship;" (ii) all financial securities required of the Company shall be released based upon "readiness to ship", (iii) the Buyer shall pay reasonable storage and handling charges incurred by the Company on the Buyer's behalf in the circumstances; (iv) risk of loss shall transfer to the Buyer upon "readiness to ship," (v) the Buyer shall be responsible for insuring the Equipment, and (vi) the Buyer shall inspect at delivery and give notice as soon as practical of any loss, damage or shortage evident by visual inspection and quantity count.

4. TITLE AND RISK OF LOSS

(a) Title and risk of loss passes to the Buyer upon the Company's delivery of the Equipment to the Delivery Point. If for any reason the Buyer (or the Buyer's transporting carrier) fails to accept delivery of the Equipment on the date on which the Equipment has been delivered to the Delivery Point or if the Company is unable to ship the Equipment because the Buyer (or the Buyer's transporting carrier) has not provided appropriate instructions, documents, licenses or authorizations: (i) risk of loss to the Equipment shall pass to the Buyer; (ii) the Equipment shall be deemed to have been delivered.

(b) As collateral security for the payment of the Purchase Price of the Equipment, the Buyer hereby grants to the Company a lien on and security interest in and to all of the right, title and interest of the Buyer in, to and under the Equipment, wherever located, and whether now existing or hereafter arising or acquired from time to time, and in all accessions thereto and replacements or modifications thereof, as well as all proceeds (including insurance proceeds) of the foregoing. The security interest granted under this provision constitutes a purchase money security interest under the Georgia Uniform Commercial Code.

5. LIMITATION OF LIABILITY; LIMITED WARRANTY; WARRANTY DISCLAIMER

(a) THE COMPANY SHALL NOT BE LIABLE FOR ANY SPECIAL, INCIDENTAL, INDIRECT, EXEMPLARY, PUNITIVE, OR CONSEQUENTIAL DAMAGES (INCLUDING WITHOUT LIMIT LOST PROFITS, PRODUCTIVITY LOSSES, ECONOMIC LOSSES, OR BUSINESS DOWNTIME) OR FOR ANY SUCH LOSS, DAMAGE, EXPENSE, DIRECTLY OR INDIRECTLY ARISING FROM THE USE OF THE EQUIPMENT, SERVICES, SPARE OR REPLACEMENT PARTS, OR FROM ANY OTHER CAUSE WHETHER BASED IN WARRANTY, NEGLIGENCE, TORT, CONTRACT OR OTHERWISE, AND REGARDLESS OF ANY ADVICE OR RECOMMENDATION THAT MAY HAVE BEEN RENDERED CONCERNING THE PURCHASE, INSTALLATION OR USE OF THE EQUIPMENT, SERVICES, SPARE OR REPLACEMENT PARTS WHETHER OR NOT HAVING BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES.

(b) THE BUYER HEREBY RELEASES THE COMPANY OF ANY SUCH LIABILITY AND COVENANTS NOT TO SUE THE COMPANY FOR ANY SUCH DAMAGES.

(c) IN NO EVENT SHALL THE COMPANY'S AGGREGATE LIABILITY UNDER ANY CIRCUMSTANCES EXCEED AN AMOUNT EQUAL TO THE PURCHASE PRICE OF THE EQUIPMENT.

(d) The Company warrants that at the time of delivery the Equipment will conform to the Company's applicable specifications and to such contract specifications as are agreed to by the Company.

(e) The warranty runs for a period of twelve (12) months from the **date of initial operation** but no more than eighteen (18) months from **date of shipment** for any part or parts of the Equipment, or within one (1) year of shipment for any spare parts shipped under an Equipment order.

(f) The **Buyer must make any warranty claim by written notice** to the Product Group home office within thirty (30) days of the discovery of any defect or the claim is deemed waived.

(g) The Company reserves the right to analyze claimed defects (including return to the manufacturing location, transportation prepaid, for inspection, if required by the Company). The Company, at its option, shall repair or replace defective parts which the Company deems to be defective, Ex Works (INCOTERMS® (most recent version)) at the Product Group manufacturing location, **but shall not install or be liable for the installation of such parts**.

(h) Expenses incurred by the Buyer in replacement, repair or return of the Equipment, or of any parts, will only be reimbursed if preauthorized by the Company.

(i) This warranty is the **Buyer's exclusive remedy** and the extent of the Company's liability for breach of warranties, representations, instructions, or for defects in connection with the sale or use of the Equipment.

(j) **Warranty adjustments or replacements shall not extend the initial warranty period**.

(k) THE WARRANTY IS IN LIEU OF ALL OTHER WARRANTIES OR REPRESENTATIONS, ORAL, EXPRESS, OR IMPLIED, INCLUDING WITHOUT LIMIT WARRANTIES THAT EXTEND BEYOND THE DESCRIPTION OF THE EQUIPMENT. THERE ARE NO EXPRESS WARRANTIES OTHER THAN THOSE CONTAINED IN PARAGRAPH 5 ("LIMITATION OF LIABILITY; LIMITED WARRANTY; WARRANTY DISCLAIMER") AND TO THE EXTENT PERMITTED BY LAW THERE ARE NO IMPLIED WARRANTIES OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE.

(l) **The warranty does not apply to**: expendable items; ordinary wear and tear; altered units; units repaired by persons not expressly approved by the Company; or, to damage caused by accident, the elements, abuse, misuse, temporary heat, overloading, erosive or corrosive substances, or the alien presence of oil, grease, scale, deposits or other contaminants.

(m) The warranty is conditioned upon the Equipment being properly installed, maintained and operated within its capacity, under normal load and service conditions, with competent, supervised operators and, if the Equipment uses water, with proper water conditioning.

(n) **Excluded from warranty** is damage resulting from any of: foaming caused by chemical conditions of the water; corrosion or caustic embrittlement; or improper or inadequate treatment of feedwater or conditioning of boiler water or the supply of improper or inadequate fuel. Preauthorized freight and/or labor for defective items will be reimbursed (exclusive of tasks normally performed as manufacturing location maintenance).

(o) **Warranty may be voided** by the Buyer's modifications or repairs if the Buyer proceeds without receiving the Company's technical advice. **Refractory** is inherently vulnerable to conditions of service and is warranted only to be installed as specified and the refractory is specifically excluded from any other warranty.

(p) The Equipment, accessories and other parts and components not manufactured by the Company are warranted only to the extent of and by the original manufacturer's warranty to the Company; in no event shall such other manufacturer's warranty create any more extensive warranty obligations of the Company to the Buyer than the Company's warranty covering the Equipment manufactured by the Company.

6. TERMINATION

(a) **Orders are not cancelable**.

(b) In the event of termination prior to completion, the Buyer shall pay the Company's direct and indirect costs, expenses, overhead and reasonable profit for work performed and materials purchased. Materials paid for will be available "As Is" to the Buyer without warranty; however, partially completed products are not available for completion by others.

(c) If performance by the Company of this Agreement is prohibited or significantly restricted by any governmental agencies, or by laws, rules or regulations of any government, the Company, at its option, may cancel this Agreement without liability.

THE CLEAVER-BROOKS COMPANY, INC. GENERAL TERMS AND CONDITIONS OF SALE (continued)

7. EXCUSED DELAY ("FORCE MAJEURE")

(a) The Company shall not be liable for loss, damage, or failure to perform resulting from causes beyond the Company's reasonable control, or from strikes, labor difficulties, lockouts, acts or omissions of any governmental authority or the Buyer, insurrection, riot, war, fires, floods, Acts of God, breakdown of essential machinery, accidents, priorities or embargoes, tariffs, car and material shortages, delays in transportation or inability to obtain labor, materials or parts from usual sources. Any such delay shall be excused for the time reasonably necessary to compensate for the delay.

(b) If performance by the Company of this Agreement is prohibited or significantly restricted by any governmental agencies, or by laws, rules or regulations of any government, the Company, at its option, may cancel this Agreement without liability.

8. INSURANCE

(a) The Company provides certificates of insurance as required for work performed at the Product Group manufacturing location (workers compensation, commercial general liability, property). After the risk of loss of and damage to the Equipment passes to the Buyer and the Owner, until the Equipment is finally accepted and the Purchase Price is paid in full, and all obligations of the Company are concluded, the Buyer shall provide and maintain property, boiler and machinery and builders risk insurance in the names of the Buyer, the Owner and the Company, as their interests may appear, for the total value of the Equipment and for all work performed in the erection thereof, against risk of fire, lightning, windstorm, aircraft and explosion, including inherent dangers and boiler explosion. The proceeds of such insurance shall be applied first to the cost of repairing and replacing the Equipment and work destroyed or damaged.

9. BACKCHARGES

(a) Items delivered by the Company may require work or revision after shipment, whether for repair of damage (transit, unloading, handling, or damage by other contractors), adaptation to site interface conditions with existing facilities or work of other contractors, or otherwise. If the Buyer notifies and informs the Company, the Company shall promptly advise the Buyer of the applicable standards or technical guidelines for such work, and the extent of the Company's other obligations, if any, with respect to such work. The Company will use its best efforts in the circumstances to assist the Buyer to obtain resources suitable for such work. Any work the Buyer intends to be done at the Company's expense requires the Company's prior approval as to: scope; identification of who will perform such work; applicable quality standards; arrangements for the time, place and urgency of such work; an agreed price or estimate of cost; and, the opportunity for the Company to have a representative in attendance. Costs claimed for work done without prior approval shall not be accepted as backcharges.

10. TECHNICAL SUPPORT

(a) Start-up technical support, if provided by the Company, is technical advice only, and excludes on-site labor. Care, custody, control, and compliance on-site during installation and start up are the responsibility of the Buyer. Representatives of the Company are authorized only to advise and consult with the Buyer. No representative of the Company is authorized or licensed to operate the Equipment. All **preliminary operations** and demonstration of capacity and performance guarantees, if required, prior to final acceptance, shall be performed by the Buyer.

11. WORK BY OTHERS: ACCESSORY AND SAFETY DEVICES; USE BEFORE START UP

(a) The Company is a supplier of the Equipment, and shall have no responsibility for labor or work of any nature relating to the installation or operation or use of the Equipment, all of which shall be performed by the Buyer or others. The Buyer shall furnish accessory and safety devices desired by it and/or required by law or OSHA standards for the Buyer's use of the Equipment. The Buyer shall install and operate the Equipment in accordance with all code requirements and other applicable laws, rules, regulations, ordinances, and Company's specifications, operating instructions, and manuals. If damage to the Equipment or other property or injury to persons is caused by use or operation of the Equipment prior to its being placed in normal operation ("Start up"), then the Buyer shall indemnify, defend, and hold the Company harmless from all resulting claims, damages, liability, costs and expenses.

12. COMPLIANCE WITH THE LAW

(a) The Buyer shall comply with all applicable laws, regulations and ordinances.

(b) The Buyer shall maintain in effect all the licenses, permissions, authorizations, consents and permits that it needs to carry out its obligations under this Agreement.

(c) The Buyer shall comply with all export and import laws of all countries involved in the sale of the Equipment under this Agreement or any resale of the Equipment by the Buyer.

(d) The Buyer assumes all responsibility for shipments of the Equipment requiring any government import clearance.

(e) The Company may cancel this Agreement if any governmental authority imposes antidumping or countervailing duties or any other penalties on the Equipment.

(f) If any changes are required in the Equipment to meet the approval of applicable authorities, the Buyer shall inform the Company of such changes and shall reimburse it for changes made to comply.

13. LIMITED LICENSE

(a) The Buyer agrees that the Company has spent considerable time and money developing proprietary hardware and software components that are incorporated into the Equipment. Nothing in this Agreement is intended to grant or create any right or license to the Buyer to copy, reverse engineer, disclose, publish, distribute or alter any pre-existing software, patent rights, copyrights, trademarks or other intellectual property rights owned or controlled by the Company, except as necessary for the Buyer to use the Equipment in accordance with this Agreement.

14. CONFIDENTIAL INFORMATION

(a) All non-public, confidential or proprietary information of the Company, including, but not limited to, specifications, samples, patterns, software, designs, patented and unpatented intellectual property, plans, drawings, documents, data, business operations, customer lists, pricing, discounts or rebates, disclosed by the Company to the Buyer, whether disclosed orally or disclosed or accessed in written, electronic or other form or media, and whether or not marked, designated or otherwise identified as "confidential," in connection with this Agreement is confidential, solely for the use of performing under this Agreement and may not be disclosed or copied unless authorized in advance by the Company in writing.

(b) Upon the Company's request, the Buyer shall promptly return all documents and other materials received from the Company.

(c) This Paragraph ("CONFIDENTIAL INFORMATION") does not apply to information that is: (i) in the public domain; (ii) known to the Buyer at the time of disclosure; or (iii) rightfully obtained by the Buyer on a non-confidential basis from a third party.

(d) The Company shall be entitled to injunctive relief for any violation of this Paragraph ("CONFIDENTIAL INFORMATION").

15. INTELLECTUAL PROPERTY

(a) The Company shall defend the Buyer in any suits instituted against the Buyer for infringement of any claim of any United States Patent covering solely the structure of the Equipment as originally manufactured by the Company per the Company's specifications, exclusive of combination or modification by the Buyer. This obligation applies, provided that the Buyer (i) gives the Company immediate notice in writing of any such claim or institution or threat of such suit; (ii) authorizes the Company to control settlement of the same, and (iii) gives all needed information, assistance and authority to enable the Company to do so. If the Company elects to defend any such suit and the structure of the said Equipment is held to infringe any such United States Patent, and if the Buyer's use thereof is enjoined, the Company shall, at its expense and at its option: (i) obtain for the Buyer the right to continue using the Equipment, (ii) supply non-infringing Equipment for installation by the Buyer, (iii) modify the Equipment so that it becomes non-infringing, or (iv) refund the then market value of the Equipment.

(b) To the extent arising from the Company incorporating a design or modification requested by the Buyer, the Buyer shall defend and indemnify the Company against all expenses, costs, and loss by reason of any real or alleged infringement.

(c) The Company's proposal, the resultant contract, and all **proprietary or confidential information** exchanged between the Company and the Buyer in connection therewith, shall be treated as confidential and be used only for performance of the contract.

16. RELATIONSHIP OF THE PARTIES

(a) The relationship between the parties is that of independent contractors. Nothing contained in this Agreement shall be construed as creating any agency, partnership, joint venture or other form of joint enterprise, employment or fiduciary relationship between the parties and neither party shall have authority to contract for or bind the other party in any manner whatsoever. This Agreement is for the sole benefit of the parties hereto and their respective successors and permitted assigns and nothing herein, express or implied, is intended to or shall confer upon any other person or entity any legal or equitable right, benefit or remedy of any nature whatsoever under or by reason of this Agreement.

17. RESOLUTION OF DISPUTES

(a) Any waiver by a party of any right shall not be considered a continuing waiver in any other instance.

(b) Any controversy or claim arising out of or relating to this contract, or the breach thereof, and not amicably resolved within thirty (30) days from referral to senior executives of each party, or to non-binding mediation, shall be settled by arbitration administered by the **American Arbitration Association** ("AAA") under its **Commercial Arbitration Rules** (with **Expedited Procedures**), with proceedings to be held by one (1) arbitrator at a locale to be determined by an AAA Case Management Center, unless otherwise agreed, and judgement on the award rendered by the arbitrator may be entered in any court having jurisdiction thereof.

(c) This Agreement shall be construed under the internal laws of the State in which is located the Product Group home office, without regard to conflict of law principles. Except as otherwise provided in Paragraph 5 ("LIMITATION OF LIABILITY; LIMITED WARRANTY; WARRANTY DISCLAIMER"), any claim arising under or in connection with this Agreement shall be asserted under this provision within two (2) years after the claim arises or be forever waived and barred. Invalidity or unenforceability of one (1) or more provisions of this Agreement shall not affect any other provision of this Agreement.

18. RECOVERY OF FEES AND EXPENSES

(a) In the event arbitration or suit is brought or an attorney is retained by the Company to enforce these Terms and Conditions or to collect any money hereunder, or to collect any money damages for breach thereof, the Company shall be entitled to recover, in addition to other remedy, reimbursement for reasonable attorney's fee, court costs, costs of investigation and other related expenses incurred in connection therewith.

19. BUY AMERICAN

(a) If this purchase is subject to a mandatory "Buy American" clause, the applicable clause must be provided for review by the company before compliance may be affirmed.

(b) Products of the Company may originate in the USA, Canada, or Liechtenstein.

20. INTERNATIONAL CONVENTION

(a) The United Nations Convention on Contracts for the International Sale of Goods (1980) shall not apply to international, cross border sales of the Company.

THE CLEAVER-BROOKS COMPANY, INC. GENERAL TERMS AND CONDITIONS OF SALE (continued)

21. MISCELLANEOUS

(a) THIS AGREEMENT IS THE COMPLETE AGREEMENT BETWEEN THE COMPANY AND THE BUYER AND NO ADDITIONAL OR DIFFERENT TERM OR CONDITION STATED BY THE BUYER SHALL BE BINDING UNLESS AGREED BY THE COMPANY IN WRITING.

(b) No course of prior dealings and no usage of the trade shall be relevant to supplement or explain any terms used herein.

(c) This Agreement may be modified only by a writing signed by both the Company and the Buyer and shall be governed by and construed in accordance with the internal laws of the State of Georgia without giving effect to any choice or conflict of law provision or rule (whether of the State of Georgia or any other jurisdiction) that would cause the application of the laws of any jurisdiction other than those of the State of Georgia.

(d) The failure of the Company to insist upon strict performance of any of the terms and conditions stated herein shall not be considered a continuing waiver of any such term or condition or any of the Company's rights. If any term or provision of this Agreement is invalid, illegal or unenforceable in any jurisdiction, such invalidity, illegality or unenforceability shall not affect any other term or provision of this Agreement or invalidate or render unenforceable such term or provision in any other jurisdiction.

22. PRODUCT GROUP CONDITIONS

(a) Supplemental conditions (below) also apply for The Cleaver-Brooks Company, Inc. Product Groups.

SUPPLEMENTAL CONDITIONS for the PACKAGED BOILER SYSTEMS PRODUCT GROUP

These provisions amend the indicated articles of THE CLEAVER-BROOKS COMPANY, INC. GENERAL TERMS AND CONDITIONS OF SALE (above)

[Add to **2. TERMS AND PRICES**]

[Add to 2.a] The **performance milestones for payment** for projects valued at or above $250,000 are as follows unless otherwise indicated in the Proposal to which these conditions are attached:

- (i) Upon Issuance of Submittals: .... **20%** of the Contract Price (Net 30 Days)
- (ii) Upon Release for Production: .... **30%** of the Contract Price (Net 30 Days)
- (iii) Upon Readiness for Shipment: .... **50%** of the Contract Price (Net 30 Days)

[Add to **6. TERMINATION**]

(d) If the Buyer's circumstances change after an order is accepted, and the Buyer is unable to use ordered items or similar items, then subject to the Company's express written consent, the buyer may **return for credit** such unneeded items as have been delivered under the order, which will be accepted as returns if they are unused, undamaged, and current inventory, subject to the normal restocking charge.

23. CANCELLATION SCHEDULE

(a) The cancellation schedule for projects is as follows unless otherwise indicated in the Proposal to which these conditions are attached:

- (i) After Receipt of Purchase Order: .... Up to **25%** of the Contract Price based on Costs and Conditions of Sale (Net 30 Days)
- (ii) 1-30 Days After Drawing Approval: .... Up to **50%** of the Contract Price based on Costs and Conditions of Sale (Net 30 Days)
- (iii) Over 30 Days After Drawing Approval: .... Up to **75%** of the Contract Price based on Costs and Conditions of Sale (Net 30 Days)
- (iv) After Final Assembly: .... Up to **100%** of the Contract Price based on Costs and Conditions of Sale (Net 30 Days)

SUPPLEMENTAL CONDITIONS for the ENGINEERED BOILER SYSTEMS PRODUCT GROUP

These provisions amend the indicated articles of THE CLEAVER-BROOKS COMPANY, INC. GENERAL TERMS AND CONDITIONS OF SALE (above)

[Add to **2. TERMS AND PRICES**]

[Add to 2.a] The **performance milestones for payment** for projects valued at or above $250,000 are as follows unless otherwise indicated in the Proposal to which these conditions are attached:

- (i) Upon Receipt of Purchase Order: .... **10%** of the Contract Price (Net 30 Days)
- (ii) Upon Issuance of Drawing Submittals (Mechanical GA and P&ID Drawings): .... **30%** of the Contract Price (Net 30 Days)
- (iii) Upon Completion of Hydrostatic Test: .... **35%** of the Contract Price (Net 30 Days)
- (iv) Upon Readiness for Shipment: .... **25%** of the Contract Price (Net 30 Days)

[Add to 2.b] If the price includes **allowed transportation or other shipping charges**, then increases in transportation rates, demurrage, special detention, or other shipping charges, occurring after the date of quotation shall be added to the Purchase Price.

[Add to 2.c] The Company may, but shall not be obligated to, incorporate into the Equipment any **upgrades or applicable changes in the Company's standard specifications**, design, construction, arrangement or components.

[Add to **3. DELIVERY**]

[Add to 2.b] The Company will endeavor to make shipment of orders as scheduled; however, all shipment dates are approximate only, and the Company reserves the right to readjust shipment schedules.

24. CANCELLATION SCHEDULE

(a) The cancellation schedule for projects is as follows unless otherwise indicated in the Proposal to which these conditions are attached:

- (i) Up to 14 Days After Receipt of Purchase Order: .... **0%** of the Contract Price (Net 30 Days)
- (ii) Over 14 Days After Receipt of Purchase Order: .... **25%** of the Contract Price (Net 30 Days)
- (iii) Up to 30 Days After Drawing Approval: .... **45%** of the Contract Price (Net 30 Days)
- (iv) 31-60 Days After Drawing Approval: .... **55%** of the Contract Price (Net 30 Days)
- (v) 61-90 Days After Drawing Approval: .... **75%** of the Contract Price (Net 30 Days)
- (vi) Over 90 Days After Drawing Approval: .... **100%** of the Contract Price (Net 30 Days)

25. FOUNDATIONS

(a) The Company shall provide the Buyer with General Arrangement drawings showing the Equipment with reference to foundations, including loading diagrams.

(b) The Company shall not be responsible for the depth of the footings, size or accuracy of the foundations or anchor bolts, or the character of the materials selected for their construction.

(c) Adequate foundations, having plan measurements in accordance with such drawings including foundation bolts and plates, concrete work, all grouting, and excavation, shall be furnished in place in due time by the Buyer.

(d) The Company shall not be responsible for any damages, or repairs necessary to the Equipment furnished by it, caused by or resulting from defects in or settlement of the foundations.

26. SUPPORTING STEEL

(a) Unless otherwise stated, any supporting steel to be furnished by the Company as specified in this Proposal will be designed to support the Equipment which the Company proposes to furnish and will be designed in accordance with the latest Rules of the American Institute of Steel Construction.

(b) If the Company is required to increase the size or weight of its supporting structures to conform to other than the Rules of the American Institute of Steel Construction or because of additional loadings imposed by the Buyer, the Buyer shall reimburse the Company for the additional steel and work required.

ATTACHMENT D-2

Emission Unit/Control Technology

Emission Unit	A06
Emission Unit Description	Nationwide/Nebraska Boiler
Control Technology	Low NO_x Burner with FGR
Emission Reduction[1] (%)	33%
Baseline Emission Rate[2] (tons/year)	0.72

Annualized Capital Costs

Initial Capital Investment[3]	$557,629
Direct & Indirect Costs[4]	$0
Total Capital Investment	$557,629
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$75,764

Annual Operating Costs

Total Annual Operating Cost	$0
Total Annualized Cost	$75,764

Cost Effectiveness

Emissions Reduction (tons/year)	0.24
Cost Effectiveness of NOx Reduction (per	$315,683

Notes:

[1] NO_x emissions reduced from 30 ppm to 20 ppm.

[2] Actual emissions for 2020 (max of 2019 - 2021).

[3] Cost based on vendor estimate.

[4] Installation, startup and testing (accounted for in vendor estimate).

Budget Proposal

Saguaro Power Burner Retrofit

To: Scott Mcnulty
Principal Geologist
Broadbent Air Quality Division
8 W Pacific Ave,
Henderson, NV 89015 United States
(702) 563-0600
Smcnulty@broadbentinc.com

From: Ryland Whitaker
R.F. MacDonald Company
6651 Schuster Street

Las Vegas, NV 89118 United States
(725)229-3368
ryland.whitaker@rfmacdonald.com

September 28, 2022

Dear Scott,

Through a steadfast commitment to research, development, strategic acquisitions, and a focus on providing boiler room solutions for more than 80 years, Cleaver-Brooks is the sole provider of integrated boiler, burner, and controls solutions. With the #1 market share in North America, Cleaver-Brooks is the global leader in designing and manufacturing integrated boiler room systems, and the Cleaver-Brooks brand is globally synonymous with the highest quality, best reliability, and creative innovation in boiler room solutions. Industry-leading proprietary burners, controls, components, and accessories engineered by Cleaver-Brooks perform together seamlessly at peak energy and emissions efficiency.

Cleaver-Brooks offers the broadest range of integrated boiler room systems, subsystems, components and accessories in the market, giving it a distinct competitive advantage as a complete solutions provider across commercial, industrial, and institutional markets. A principal component of the Cleaver-Brooks strategy is to offer the most advanced and completely integrated boiler room systems that satisfy diverse energy demands, high-efficiency performance, ultra-low emissions, safety, reliability, and convenience from utilizing a single-source manufacturer.

From the Power of Total Integration, Cleaver-Brooks offers boiler room systems including mission-critical subsystems performing water treatment, heat recovery, integrated system controls, and maintained by a worldwide dedicated sales and service representative network. All sales and service representatives employ trained technicians to provide first-class routine maintenance and repair services in accordance with national, state/provincial, and local codes and standards.

As a Cleaver-Brooks Representative Association (CBRA) member near you, R.F. MacDonald Company has produced this proposal from your system requirements and equipment specifications. At your convenience, please review this proposal, and contact me regarding any questions or comments.

Sincerely,

Ryland Whitaker
R.F. MacDonald Company
6651 Schuster Street
Las Vegas, NV 89118 United States
(725)229-3368
ryland.whitaker@rfmacdonald.com

CleaverBrooks

System Requirements

Proposal Number: 29850248 / Proposal Date: 09/16/22

Job Name: Saguaro Power Burner Retrofit / Project Name: Saguaro Power Burner Retrofit

Configurable Burner

NCB Burner System

- For new boilers or retrofit applications/hr
- Natural Gas and light oil firing/hr
- Millions of configurations possible to satisfy your specific needs
- Available to < 30 ppm NOx, < 50 ppm CO
- 12 to 360 MMBTU/hr

The NCB burner is a unique packaged burner system for new boilers and retrofit markets. These burners use advanced CFD modeling, and are equipped with advanced Natcom® design features, including externally adjustable gas injectors, Class-III igniters, atomizers with coupling block valves, which you can complement with your choice among a variety of industrial-grade controls, valves, switches, and gauges.

Natcom® burners feature emissions reductions of 50% compared to flaring and can achieve emissions goals of 9 ppm NOx. The high-efficiency burner design is engineered for multi-fuel firing, including renewables.

NCB-085 Burner

Technical Data Sheet

For indoor applications, uncontrolled or 30 ppm NOx emissions

85 MM BTU/H NG; 81 MM BTU/H #2 OIL

Designed for furnace dimensions of at least:	Physical arrangement:	Combustion Control System (CCS) compatibility options:	Fuel Options:	Choice of NFPA or CSA compliance for U.S. or Canadian units, respectively (contact us for TSSA compliance).
H=8.97' W=6.69' Lturn=15.33' Ltot=18.00'	FD fan, fuel train and control panel are windbox mounted. Right- or left-hand drum arrangements available.	Fully Metered (FM), Parallel Positioning (PP) and Single Point Positioning (SP). All systems use 4-20mA and pneumatic actuators.	Main Fuel: Natural gas and/or #2 oil. Igniter fuel: Natural gas and/or propane.	

Performance guarantees

	NG, no FGR	#2 Oil, no FGR	NG, 12% FGR	#2 Oil, 12% FGR
Excess Air %*	15	15	15	15
NOx emissions ppmvd @3%O_2	70	110	30	75
CO emissions ppmvd @3%O_2	50	75	50	75
VOC lb/MM BTU (HHV)	0.004	0.004	0.004	0.004
Total PM lb/MM BTU (HHV)	0.01	0.05	0.01	0.05
Turndown	10	8	10	8

Performance guarantees are based on normal operating conditions and valid from 25% to 100% MCR, boiler with gas tight furnace division wall and to nominal operating pressure and temperature. Igniter emissions are not guaranteed. For application where CB does not provide the controls, emissions are guaranteed in manual mode only. SOx emissions are not burner dependent and depend solely on the sulfur content of the fuel. Burner/boiler systems are not intended for automatic recycling use. Fan motors of 100 HP and above are only offered with manual start/stop control. Please contact your local representative for more details.

*Excess air given for MCR only.

CleaverBrooks®

Budget Quote Summary

Proposal Number: 29850248 / Proposal Date: 09/16/22

Job Name: Saguaro Power Burner Retrofit / Project Name: Saguaro Power Burner Retrofit

Product Model: NATCOM		
Item	**Qty.**	**Description**
#1	1	**Reference: 1** Configured in the Custom NATCOM program.
#2	1	Burner Model: NCB-230
#3	1	Fuels Included: Gas
#4	1	Burner Heat Input (MMBTU/hr): 85
#5	1	Guaranteed NOx Emissions, Gas (PPM @3% O2): 30
#6	1	Type of Control: Full Metering
#7	1	Burner Fan Motor HP: 150
#8	1	Burner Fan Location: Windbox Mounted
#9	1	Available Gas Pressure at Regulator Inlet: 25 - 40 psig
#10	1	Oil Pressure Required @ Train Inlet: 150 psig
#11	1	Turndown on Natural Gas: 10:1
#12	1	Turndown Firing Oil: 8:1
#13	1	Variable Frequency Drive Included: Y
#14	1	O2 Trims: Yes
#15	1	Boiler Control Model: HAWK 4500
#16	1	Ambient Temperature Range: 50 - 100 °F
#17	1	Site Elevation: < 2500 ft ASL
		Product Price to Customer (USD): $

CleaverBrooks®

Budget Quote Summary

Proposal Number: 29850248 / Proposal Date: 09/16/22

Job Name: Saguaro Power Burner Retrofit / Project Name: Saguaro Power Burner Retrofit

Item	Qty.	Product Model	PTC (USD)
#1	1	NATCOM	$507.629.00
		Subtotal Price to Customer (USD):	$507,629.00
		Cost Adder for 20ppm(USD):	$50,000.00
		Freight (EXW - Ex Works Factory) Cost (USD):	NA
		Total Price to Customer (USD):	$557,629.00

CLEAVER-BROOKS OFFERING

Cleaver-Brooks offers to furnish the Equipment described herein for the purchase price noted, exclusive of all taxes. Prices quoted are firm for 30 days from the date of the Cleaver-Brooks Proposal subject to adjustment as noted. Standard Cleaver-Brooks **payment terms** are *unconditional net 30 from the date of readiness for shipment or unless otherwise specified in this Proposal*. Cleaver-Brooks will review your order prior to acceptance (and acknowledgment) and order entry. Until acceptance and order entry, the Equipment is **subject to prior sale**. Incorporation of technical specifications or requirements different from or additional to the Cleaver-Brooks Proposal and not previously reviewed by Cleaver-Brooks will extend the order review process and may postpone or prevent acceptance of your order and order entry. Cleaver-Brooks does not agree and will not agree to **INCIDENTAL, CONSEQUENTIAL AND LIQUIDATED DAMAGES OR IMPLIED WARRANTIES**. Cleaver-Brooks does not agree and will not agree to, unless specifically set forth in an agreement in writing having an authorized Cleaver-Brooks signature: (1) **terms and conditions** in your order that are different from or additional to those of the Cleaver-Brooks Proposal; (2) **technical specifications**, technical requirements or descriptions of the goods and services ordered that are different from or additional to those of the Cleaver-Brooks Proposal; or (3) **generalized expressions** such as "per plans and specifications."

CLEAVER-BROOKS PRICE ADJUSTMENT POLICY

The price quoted in the Cleaver-Brooks Proposal is firm for thirty (30) days from the Proposal date if shipment of the Equipment is made within six (6) months from the date of the Cleaver-Brooks Proposal or contract document if no Proposal was issued. If the Equipment is not shipped within such six (6) months, the contract price shall be increased by one percent (1%) for each thirty (30) days or fraction thereof that shipment is deferred beyond six (6) months from the date of the Cleaver-Brooks Proposal or contract document.

PROPOSED PAYMENT TERMS

Amount At or Exceeds $250,000: Yes
Payment Terms: Progress Payments
Terms Description:
Note: May require Cleaver-Brooks review if other than 20%/30%/50% referenced in ¶ 1(a).

PROPOSED SHIPPING TERMS

[x] EXW – Ex Works Factory
[ ] CIP – Carriage and Insurance Paid to
[ ] OTHER:______________________
Freight Allowed To Location:______________________
Note: Freight unloading by others.

BUYER OF CLEAVER-BROOKS EQUIPMENT

Buyer Representative - Printed First and Last Name

Buyer Representative - Company Name

,
Buyer Representative - Company Address, State/Province, Area Code, and Country

Buyer Representative - Phone Number

Buyer Representative - Email Address

Buyer Representative - Signature

/ /
Buyer Representative - Date Accepted (MM/DD/YYYY)

CLEAVER-BROOKS SALES REPRESENTATIVE

Ryland Whitaker
Sales Representative - Printed First and Last Name

R.F. MacDonald Company
Sales Representative - Company Name

10261 MATERN PLACE
SANTA FE SPRINGS, CA 90670
United States
Sales Representative - Company Address, State/Province, Area Code, and Country

(725)229-3368
Sales Representative - Phone Number

ryland.whitaker@rfmacdonald.com
Sales Representative - Email Address

Sales Representative - Signature

09/16/22
Sales Representative - Date Offered

CLEAVER-BROOKS TERMS AND CONDITIONS OF SALE ON NEXT PAGE

CleaverBrooks®

Terms and Conditions of Sale

Date Revised: July 23, 2021

THE CLEAVER-BROOKS COMPANY, INC. GENERAL TERMS AND CONDITIONS OF SALE

1. OFFER AND CONTRACT

(a) Through its proposal (the "Proposal") The Cleaver-Brooks Company, Inc. (the "Company") offers to sell its products, systems or parts (the "Equipment") for the purchase price (the "Purchase Price") on these terms and conditions of sale.

(b) UPON WRITTEN ACCEPTANCE OF THE PROPOSAL BY THE BUYER, THE PROPOSAL AND THESE TERMS CONSTITUTE THE COMPLETE AGREEMENT BETWEEN THE COMPANY AND THE BUYER ("THIS AGREEMENT"). ANY ADDITIONAL OR DIFFERENT TERMS ARE REJECTED UNLESS AGREED TO BY THE COMPANY IN A SIGNED AMENDMENT AFTER REVIEW AT THE PRODUCT GROUP HOME OFFICE.

(c) Except as indicated below, this **Proposal is valid for thirty (30) days** subject to written withdrawal by the Company at any time prior to receipt of written acceptance by the Buyer.

(d) The Purchase Price and any delivery dates of this Proposal are **subject to prior sales that occur before written acceptance by the Buyer and increased material costs**.

(e) Orders received are scheduled for production as proposals are accepted in writing by the Buyer.

(f) If at the time the Product Group home office receives a written acceptance of a proposal, and the then available production lead time at the Product Group manufacturing location does not allow for shipment within the number of weeks offered in the Proposal, then the Purchase Price and any delivery dates shall be adjusted based upon the next available production and delivery dates.

2. TERMS AND PRICES

(a) Standard terms of payment are thirty (30) days net from the date of invoice for completion of performance milestones for payment, including readiness of the Equipment for shipment. Partial shipments of units under multiple unit orders shall be invoiced and paid separately. The Company will waive lien rights and release payment claims to the extent of payments received. The Company may require a letter of credit from the Buyer.

(b) Any excise, sales, privilege, use or any other local, state, or federal taxes which the Company may be required to pay, arising from the sale, delivery, or use of the Equipment and any applicable prepaid freight, will be added to the Purchase Price and invoiced separately.

(c) If the Buyer requests changes in scope or schedule, or if the Buyer delays production or shipment of the Equipment, the Purchase Price and any delivery dates shall be equitably adjusted to reflect changes caused thereby.

(d) Availability and costs of any proposed surety bonding (or other financial securities) are determined by providers thereof at the time of award and the costs of such surety bonding shall be added to the Purchase Price. The Company does not commit to provide a particular financial security. All financial securities issued will be subject to agreed expiration dates, and reduce in amount as performance milestones are accomplished.

(e) The Buyer shall pay **interest on all late payments** at the lesser rate of 1.5% per month or the highest rate permissible under applicable law, calculated daily and compounded monthly.

(f) The Buyer shall reimburse the Company for all costs incurred in collecting any late payments, including, without limitation, attorney's fees.

(g) The Buyer shall not withhold payment of any amounts due and payable by reason of any set-off of any claim or dispute with the Company, whether relating to the Company's breach, bankruptcy, or otherwise. The Company shall not be liable for any claim by the Buyer unless and until such claim is finally adjudicated through the dispute resolution process.

(h) The Purchase Price is subject to increase before written acceptance of the Proposal by the Buyer based upon an increase of the CRU USA Midwest FOB Mill index.

(i) In addition to all other remedies available under this Agreement or at law (which the Company does not waive by the exercise of any rights hereunder), the Company shall be entitled to suspend the manufacture and/or delivery of any Equipment if the Buyer fails to pay any Company invoice within thirty (30) days of the date of the invoice.

3. DELIVERY

(a) Unless otherwise offered in this Proposal, delivery is Ex Works (INCOTERMS® (most recent version)), at the Product Group manufacturing location ("the Delivery Point").

(b) The estimated shipment date is based upon timely receipt by the Company of **Buyer's applicable information**, and of **Buyer's written approval**, or detailed exceptions to, the Company's general arrangement drawings within ten (10) business days of receipt.

(c) If the **Buyer requests to defer delivery** dates by a written request adequate to support GAAP requirements for revenue recognition by the Company, or if the Buyer fails to promptly accept the Equipment tendered for delivery, or shipment of the Equipment is otherwise delayed by causes beyond the Company's reasonable control, the following conditions shall apply: (i) payments due upon shipment (or "delivery") shall be invoiced, due and payable upon "readiness to ship;" (ii) all financial securities required of the Company shall be released based upon "readiness to ship", (iii) the Buyer shall pay reasonable storage and handling charges incurred by the Company on the Buyer's behalf in the circumstances; (iv) risk of loss shall transfer to the Buyer upon "readiness to ship," (v) the Buyer shall be responsible for insuring the Equipment, and (vi) the Buyer shall inspect at delivery and give notice as soon as practical of any loss, damage or shortage evident by visual inspection and quantity count.

4. TITLE AND RISK OF LOSS

(a) Title and risk of loss passes to the Buyer upon the Company's delivery of the Equipment to the Delivery Point. If for any reason the Buyer (or the Buyer's transporting carrier) fails to accept delivery of the Equipment on the date on which the Equipment has been delivered to the Delivery Point or if the Company is unable to ship the Equipment because the Buyer (or the Buyer's transporting carrier) has not provided appropriate instructions, documents, licenses or authorizations: (i) risk of loss to the Equipment shall pass to the Buyer; (ii) the Equipment shall be deemed to have been delivered.

(b) As collateral security for the payment of the Purchase Price of the Equipment, the Buyer hereby grants to the Company a lien on and security interest in and to all of the right, title and interest of the Buyer in, to and under the Equipment, wherever located, and whether now existing or hereafter arising or acquired from time to time, and in all accessions thereto and replacements or modifications thereof, as well as all proceeds (including insurance proceeds) of the foregoing. The security interest granted under this provision constitutes a purchase money security interest under the Georgia Uniform Commercial Code.

5. LIMITATION OF LIABILITY; LIMITED WARRANTY; WARRANTY DISCLAIMER

(a) THE COMPANY SHALL NOT BE LIABLE FOR ANY SPECIAL, INCIDENTAL, INDIRECT, EXEMPLARY, PUNITIVE, OR CONSEQUENTIAL DAMAGES (INCLUDING WITHOUT LIMIT LOST PROFITS, PRODUCTIVITY LOSSES, ECONOMIC LOSSES, OR BUSINESS DOWNTIME) OR FOR ANY SUCH LOSS, DAMAGE, EXPENSE, DIRECTLY OR INDIRECTLY ARISING FROM THE USE OF THE EQUIPMENT, SERVICES, SPARE OR REPLACEMENT PARTS, OR FROM ANY OTHER CAUSE WHETHER BASED IN WARRANTY, NEGLIGENCE, TORT, CONTRACT OR OTHERWISE, AND REGARDLESS OF ANY ADVICE OR RECOMMENDATION THAT MAY HAVE BEEN RENDERED CONCERNING THE PURCHASE, INSTALLATION OR USE OF THE EQUIPMENT, SERVICES, SPARE OR REPLACEMENT PARTS WHETHER OR NOT HAVING BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES.

(b) THE BUYER HEREBY RELEASES THE COMPANY OF ANY SUCH LIABILITY AND COVENANTS NOT TO SUE THE COMPANY FOR ANY SUCH DAMAGES.

(c) IN NO EVENT SHALL THE COMPANY'S AGGREGATE LIABILITY UNDER ANY CIRCUMSTANCES EXCEED AN AMOUNT EQUAL TO THE PURCHASE PRICE OF THE EQUIPMENT.

(d) The Company warrants that at the time of delivery the Equipment will conform to the Company's applicable specifications and to such contract specifications as are agreed to by the Company.

(e) The warranty runs for a period of twelve (12) months from the **date of initial operation** but no more than eighteen (18) months from **date of shipment** for any part or parts of the Equipment, or within one (1) year of shipment for any spare parts shipped under an Equipment order.

(f) The **Buyer must make any warranty claim by written notice** to the Product Group home office within thirty (30) days of the discovery of any defect or the claim is deemed waived.

(g) The Company reserves the right to analyze claimed defects (including return to the manufacturing location, transportation prepaid, for inspection, if required by the Company). The Company, at its option, shall repair or replace defective parts which the Company deems to be defective, Ex Works (INCOTERMS® (most recent version)) at the Product Group manufacturing location, **but shall not install or be liable for the installation of such parts**.

(h) Expenses incurred by the Buyer in replacement, repair or return of the Equipment, or of any parts, will only be reimbursed if preauthorized by the Company.

(i) This warranty is the **Buyer's exclusive remedy** and the extent of the Company's liability for breach of warranties, representations, instructions, or for defects in connection with the sale or use of the Equipment.

(j) **Warranty adjustments or replacements shall not extend the initial warranty period**.

(k) THE WARRANTY IS IN LIEU OF ALL OTHER WARRANTIES OR REPRESENTATIONS, ORAL, EXPRESS, OR IMPLIED, INCLUDING WITHOUT LIMIT WARRANTIES THAT EXTEND BEYOND THE DESCRIPTION OF THE EQUIPMENT. THERE ARE NO EXPRESS WARRANTIES OTHER THAN THOSE CONTAINED IN PARAGRAPH 5 ("LIMITATION OF LIABILITY; LIMITED WARRANTY; WARRANTY DISCLAIMER") AND TO THE EXTENT PERMITTED BY LAW THERE ARE NO IMPLIED WARRANTIES OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE.

(l) **The warranty does not apply to**: expendable items; ordinary wear and tear; altered units; units repaired by persons not expressly approved by the Company; or, to damage caused by accident, the elements, abuse, misuse, temporary heat, overloading, erosive or corrosive substances, or the alien presence of oil, grease, scale, deposits or other contaminants.

(m) The warranty is conditioned upon the Equipment being properly installed, maintained and operated within its capacity, under normal load and service conditions, with competent, supervised operators and, if the Equipment uses water, with proper water conditioning.

(n) **Excluded from warranty** is damage resulting from any of: foaming caused by chemical conditions of the water; corrosion or caustic embrittlement; or improper or inadequate treatment of feedwater or conditioning of boiler water or the supply of improper or inadequate fuel. Preauthorized freight and/or labor for defective items will be reimbursed (exclusive of tasks normally performed as manufacturing location maintenance).

(o) **Warranty may be voided** by the Buyer's modifications or repairs if the Buyer proceeds without receiving the Company's technical advice. **Refractory** is inherently vulnerable to conditions of service and is warranted only to be installed as specified and the refractory is specifically excluded from any other warranty.

(p) The Equipment, accessories and other parts and components not manufactured by the Company are warranted only to the extent of and by the original manufacturer's warranty to the Company; in no event shall such other manufacturer's warranty create any more extensive warranty obligations of the Company to the Buyer than the Company's warranty covering the Equipment manufactured by the Company.

6. TERMINATION

(a) **Orders are not cancelable**.

(b) In the event of termination prior to completion, the Buyer shall pay the Company's direct and indirect costs, expenses, overhead and reasonable profit for work performed and materials purchased. Materials paid for will be available "As Is" to the Buyer without warranty; however, partially completed products are not available for completion by others.

(c) If performance by the Company of this Agreement is prohibited or significantly restricted by any governmental agencies, or by laws, rules or regulations of any government, the Company, at its option, may cancel this Agreement without liability.

THE CLEAVER-BROOKS COMPANY, INC. GENERAL TERMS AND CONDITIONS OF SALE (continued)

7. EXCUSED DELAY (“FORCE MAJEURE”)

(a) The Company shall not be liable for loss, damage, or failure to perform resulting from causes beyond the Company’s reasonable control, or from strikes, labor difficulties, lockouts, acts or omissions of any governmental authority or the Buyer, insurrection, riot, war, fires, floods, Acts of God, breakdown of essential machinery, accidents, priorities or embargoes, tariffs, car and material shortages, delays in transportation or inability to obtain labor, materials or parts from usual sources. Any such delay shall be excused for the time reasonably necessary to compensate for the delay.

(b) If performance by the Company of this Agreement is prohibited or significantly restricted by any governmental agencies, or by laws, rules or regulations of any government, the Company, at its option, may cancel this Agreement without liability.

8. INSURANCE

(a) The Company provides certificates of insurance as required for work performed at the Product Group manufacturing location (workers compensation, commercial general liability, property). After the risk of loss of and damage to the Equipment passes to the Buyer and the Owner, until the Equipment is finally accepted and the Purchase Price is paid in full, and all obligations of the Company are concluded, the Buyer shall provide and maintain property, boiler and machinery and builders risk insurance in the names of the Buyer, the Owner and the Company, as their interests may appear, for the total value of the Equipment and for all work performed in the erection thereof, against risk of fire, lightning, windstorm, aircraft and explosion, including inherent dangers and boiler explosion. The proceeds of such insurance shall be applied first to the cost of repairing and replacing the Equipment and work destroyed or damaged.

9. BACKCHARGES

(a) Items delivered by the Company may require work or revision after shipment, whether for repair of damage (transit, unloading, handling, or damage by other contractors), adaptation to site interface conditions with existing facilities or work of other contractors, or otherwise. If the Buyer notifies and informs the Company, the Company shall promptly advise the Buyer of the applicable standards or technical guidelines for such work, and the extent of the Company’s other obligations, if any, with respect to such work. The Company will use its best efforts in the circumstances to assist the Buyer to obtain resources suitable for such work. Any work the Buyer intends to be done at the Company’s expense requires the Company’s prior approval as to: scope; identification of who will perform such work; applicable quality standards; arrangements for the time, place and urgency of such work; an agreed price or estimate of cost; and, the opportunity for the Company to have a representative in attendance. Costs claimed for work done without prior approval shall not be accepted as backcharges.

10. TECHNICAL SUPPORT

(a) Start-up technical support, if provided by the Company, is technical advice only, and excludes on-site labor. Care, custody, control, and compliance on-site during installation and start up are the responsibility of the Buyer. Representatives of the Company are authorized only to advise and consult with the Buyer. No representative of the Company is authorized or licensed to operate the Equipment. All **preliminary operations** and demonstration of capacity and performance guarantees, if required, prior to final acceptance, shall be performed by the Buyer.

11. WORK BY OTHERS: ACCESSORY AND SAFETY DEVICES; USE BEFORE START UP

(a) The Company is a supplier of the Equipment, and shall have no responsibility for labor or work of any nature relating to the installation or operation or use of the Equipment, all of which shall be performed by the Buyer or others. The Buyer shall furnish accessory and safety devices desired by it and/or required by law or OSHA standards for the Buyer’s use of the Equipment. The Buyer shall install and operate the Equipment in accordance with all code requirements and other applicable laws, rules, regulations, ordinances, and Company’s specifications, operating instructions, and manuals. If damage to the Equipment or other property or injury to persons is caused by use or operation of the Equipment prior to its being placed in normal operation (“Start up”), then the Buyer shall indemnify, defend, and hold the Company harmless from all resulting claims, damages, liability, costs and expenses.

12. COMPLIANCE WITH THE LAW

(a) The Buyer shall comply with all applicable laws, regulations and ordinances.

(b) The Buyer shall maintain in effect all the licenses, permissions, authorizations, consents and permits that it needs to carry out its obligations under this Agreement.

(c) The Buyer shall comply with all export and import laws of all countries involved in the sale of the Equipment under this Agreement or any resale of the Equipment by the Buyer.

(d) The Buyer assumes all responsibility for shipments of the Equipment requiring any government import clearance.

(e) The Company may cancel this Agreement if any governmental authority imposes antidumping or countervailing duties or any other penalties on the Equipment.

(f) If any changes are required in the Equipment to meet the approval of applicable authorities, the Buyer shall inform the Company of such changes and shall reimburse it for changes made to comply.

13. LIMITED LICENSE

(a) The Buyer agrees that the Company has spent considerable time and money developing proprietary hardware and software components that are incorporated into the Equipment. Nothing in this Agreement is intended to grant or create any right or license to the Buyer to copy, reverse engineer, disclose, publish, distribute or alter any pre-existing software, patent rights, copyrights, trademarks or other intellectual property rights owned or controlled by the Company, except as necessary for the Buyer to use the Equipment in accordance with this Agreement.

14. CONFIDENTIAL INFORMATION

(a) All non-public, confidential or proprietary information of the Company, including, but not limited to, specifications, samples, patterns, software, designs, patented and unpatented intellectual property, plans, drawings, documents, data, business operations, customer lists, pricing, discounts or rebates, disclosed by the Company to the Buyer, whether disclosed orally or disclosed or accessed in written, electronic or other form or media, and whether or not marked, designated or otherwise identified as “confidential,” in connection with this Agreement is confidential, solely for the use of performing under this Agreement and may not be disclosed or copied unless authorized in advance by the Company in writing.

(b) Upon the Company’s request, the Buyer shall promptly return all documents and other materials received from the Company.

(c) This Paragraph (“CONFIDENTIAL INFORMATION”) does not apply to information that is: (i) in the public domain; (ii) known to the Buyer at the time of disclosure; or (iii) rightfully obtained by the Buyer on a non-confidential basis from a third party.

(d) The Company shall be entitled to injunctive relief for any violation of this Paragraph (“CONFIDENTIAL INFORMATION”).

15. INTELLECTUAL PROPERTY

(a) The Company shall defend the Buyer in any suits instituted against the Buyer for infringement of any claim of any United States Patent covering solely the structure of the Equipment as originally manufactured by the Company per the Company’s specifications, exclusive of combination or modification by the Buyer. This obligation applies, provided that the Buyer (i) gives the Company immediate notice in writing of any such claim or institution or threat of such suit; (ii) authorizes the Company to control settlement of the same, and (iii) gives all needed information, assistance and authority to enable the Company to do so. If the Company elects to defend any such suit and the structure of the said Equipment is held to infringe any such United States Patent, and if the Buyer’s use thereof is enjoined, the Company shall, at its expense and at its option: (i) obtain for the Buyer the right to continue using the Equipment, (ii) supply non-infringing Equipment for installation by the Buyer, (iii) modify the Equipment so that it becomes non-infringing, or (iv) refund the then market value of the Equipment.

(b) To the extent arising from the Company incorporating a design or modification requested by the Buyer, the Buyer shall defend and indemnify the Company against all expenses, costs, and loss by reason of any real or alleged infringement.

(c) The Company’s proposal, the resultant contract, and all **proprietary or confidential information** exchanged between the Company and the Buyer in connection therewith, shall be treated as confidential and be used only for performance of the contract.

16. RELATIONSHIP OF THE PARTIES

(a) The relationship between the parties is that of independent contractors. Nothing contained in this Agreement shall be construed as creating any agency, partnership, joint venture or other form of joint enterprise, employment or fiduciary relationship between the parties and neither party shall have authority to contract for or bind the other party in any manner whatsoever. This Agreement is for the sole benefit of the parties hereto and their respective successors and permitted assigns and nothing herein, express or implied, is intended to or shall confer upon any other person or entity any legal or equitable right, benefit or remedy of any nature whatsoever under or by reason of this Agreement.

17. RESOLUTION OF DISPUTES

(a) Any waiver by a party of any right shall not be considered a continuing waiver in any other instance.

(b) Any controversy or claim arising out of or relating to this contract, or the breach thereof, and not amicably resolved within thirty (30) days from referral to senior executives of each party, or to non-binding mediation, shall be settled by arbitration administered by the **American Arbitration Association** (“AAA”) under its **Commercial Arbitration Rules** (with **Expedited Procedures**), with proceedings to be held by one (1) arbitrator at a locale to be determined by an AAA Case Management Center, unless otherwise agreed, and judgement on the award rendered by the arbitrator may be entered in any court having jurisdiction thereof.

(c) This Agreement shall be construed under the internal laws of the State in which is located the Product Group home office, without regard to conflict of law principles. Except as otherwise provided in Paragraph 5 (“LIMITATION OF LIABILITY; LIMITED WARRANTY; WARRANTY DISCLAIMER”), any claim arising under or in connection with this Agreement shall be asserted under this provision within two (2) years after the claim arises or be forever waived and barred. Invalidity or unenforceability of one (1) or more provisions of this Agreement shall not affect any other provision of this Agreement.

18. RECOVERY OF FEES AND EXPENSES

(a) In the event arbitration or suit is brought or an attorney is retained by the Company to enforce these Terms and Conditions or to collect any money hereunder, or to collect any money damages for breach thereof, the Company shall be entitled to recover, in addition to other remedy, reimbursement for reasonable attorney’s fee, court costs, costs of investigation and other related expenses incurred in connection therewith.

19. BUY AMERICAN

(a) If this purchase is subject to a mandatory “Buy American” clause, the applicable clause must be provided for review by the company before compliance may be affirmed.

(b) Products of the Company may originate in the USA, Canada, or Liechtenstein.

20. INTERNATIONAL CONVENTION

(a) The United Nations Convention on Contracts for the International Sale of Goods (1980) shall not apply to international, cross border sales of the Company.

THE CLEAVER-BROOKS COMPANY, INC. GENERAL TERMS AND CONDITIONS OF SALE (continued)

21. MISCELLANEOUS

(a) THIS AGREEMENT IS THE COMPLETE AGREEMENT BETWEEN THE COMPANY AND THE BUYER AND NO ADDITIONAL OR DIFFERENT TERM OR CONDITION STATED BY THE BUYER SHALL BE BINDING UNLESS AGREED BY THE COMPANY IN WRITING.

(b) No course of prior dealings and no usage of the trade shall be relevant to supplement or explain any terms used herein.

(c) This Agreement may be modified only by a writing signed by both the Company and the Buyer and shall be governed by and construed in accordance with the internal laws of the State of Georgia without giving effect to any choice or conflict of law provision or rule (whether of the State of Georgia or any other jurisdiction) that would cause the application of the laws of any jurisdiction other than those of the State of Georgia.

(d) The failure of the Company to insist upon strict performance of any of the terms and conditions stated herein shall not be considered a continuing waiver of any such term or condition or any of the Company's rights. If any term or provision of this Agreement is invalid, illegal or unenforceable in any jurisdiction, such invalidity, illegality or unenforceability shall not affect any other term or provision of this Agreement or invalidate or render unenforceable such term or provision in any other jurisdiction.

22. PRODUCT GROUP CONDITIONS

(a) Supplemental conditions (below) also apply for The Cleaver-Brooks Company, Inc. Product Groups.

SUPPLEMENTAL CONDITIONS for the PACKAGED BOILER SYSTEMS PRODUCT GROUP

These provisions amend the indicated articles of THE CLEAVER-BROOKS COMPANY, INC. GENERAL TERMS AND CONDITIONS OF SALE (above)

[Add to **2. TERMS AND PRICES**]

[Add to 2.a] The **performance milestones for payment** for projects valued at or above $250,000 are as follows unless otherwise indicated in the Proposal to which these conditions are attached:

- (i) Upon Issuance of Submittals: .... **20%** of the Contract Price (Net 30 Days)
- (ii) Upon Release for Production: .... **30%** of the Contract Price (Net 30 Days)
- (iii) Upon Readiness for Shipment: .... **50%** of the Contract Price (Net 30 Days)

[Add to **6. TERMINATION**]

(d) If the Buyer's circumstances change after an order is accepted, and the Buyer is unable to use ordered items or similar items, then subject to the Company's express written consent, the buyer may **return for credit** such unneeded items as have been delivered under the order, which will be accepted as returns if they are unused, undamaged, and current inventory, subject to the normal restocking charge.

23. CANCELLATION SCHEDULE

(a) The cancellation schedule for projects is as follows unless otherwise indicated in the Proposal to which these conditions are attached:

- (i) After Receipt of Purchase Order: .... Up to **25%** of the Contract Price based on Costs and Conditions of Sale (Net 30 Days)
- (ii) 1-30 Days After Drawing Approval: .... Up to **50%** of the Contract Price based on Costs and Conditions of Sale (Net 30 Days)
- (iii) Over 30 Days After Drawing Approval: .... Up to **75%** of the Contract Price based on Costs and Conditions of Sale (Net 30 Days)
- (iv) After Final Assembly: .... Up to **100%** of the Contract Price based on Costs and Conditions of Sale (Net 30 Days)

SUPPLEMENTAL CONDITIONS for the ENGINEERED BOILER SYSTEMS PRODUCT GROUP

These provisions amend the indicated articles of THE CLEAVER-BROOKS COMPANY, INC. GENERAL TERMS AND CONDITIONS OF SALE (above)

[Add to **2. TERMS AND PRICES**]

[Add to 2.a] The **performance milestones for payment** for projects valued at or above $250,000 are as follows unless otherwise indicated in the Proposal to which these conditions are attached:

- (i) Upon Receipt of Purchase Order: .... **10%** of the Contract Price (Net 30 Days)
- (ii) Upon Issuance of Drawing Submittals (Mechanical GA and P&ID Drawings): .... **30%** of the Contract Price (Net 30 Days)
- (iii) Upon Completion of Hydrostatic Test: .... **35%** of the Contract Price (Net 30 Days)
- (iv) Upon Readiness for Shipment: .... **25%** of the Contract Price (Net 30 Days)

[Add to 2.b] If the price includes **allowed transportation or other shipping charges**, then increases in transportation rates, demurrage, special detention, or other shipping charges, occurring after the date of quotation shall be added to the Purchase Price.

[Add to 2.c] The Company may, but shall not be obligated to, incorporate into the Equipment any **upgrades or applicable changes in the Company's standard specifications**, design, construction, arrangement or components.

[Add to **3. DELIVERY**]

[Add to 2.b] The Company will endeavor to make shipment of orders as scheduled; however, all shipment dates are approximate only, and the Company reserves the right to readjust shipment schedules.

24. CANCELLATION SCHEDULE

(a) The cancellation schedule for projects is as follows unless otherwise indicated in the Proposal to which these conditions are attached:

- (i) Up to 14 Days After Receipt of Purchase Order: .... **0%** of the Contract Price (Net 30 Days)
- (ii) Over 14 Days After Receipt of Purchase Order: .... **25%** of the Contract Price (Net 30 Days)
- (iii) Up to 30 Days After Drawing Approval: .... **45%** of the Contract Price (Net 30 Days)
- (iv) 31-60 Days After Drawing Approval: .... **55%** of the Contract Price (Net 30 Days)
- (v) 61-90 Days After Drawing Approval: .... **75%** of the Contract Price (Net 30 Days)
- (vi) Over 90 Days After Drawing Approval: .... **100%** of the Contract Price (Net 30 Days)

25. FOUNDATIONS

(a) The Company shall provide the Buyer with General Arrangement drawings showing the Equipment with reference to foundations, including loading diagrams.

(b) The Company shall not be responsible for the depth of the footings, size or accuracy of the foundations or anchor bolts, or the character of the materials selected for their construction.

(c) Adequate foundations, having plan measurements in accordance with such drawings including foundation bolts and plates, concrete work, all grouting, and excavation, shall be furnished in place in due time by the Buyer.

(d) The Company shall not be responsible for any damages, or repairs necessary to the Equipment furnished by it, caused by or resulting from defects in or settlement of the foundations.

26. SUPPORTING STEEL

(a) Unless otherwise stated, any supporting steel to be furnished by the Company as specified in this Proposal will be designed to support the Equipment which the Company proposes to furnish and will be designed in accordance with the latest Rules of the American Institute of Steel Construction.

(b) If the Company is required to increase the size or weight of its supporting structures to conform to other than the Rules of the American Institute of Steel Construction or because of additional loadings imposed by the Buyer, the Buyer shall reimburse the Company for the additional steel and work required.

Appendix 8a

Saguaro RACT Analysis:
DAQ Supporting Documentation

Rob Barton

From: Justin Legg <jlegg@alzeta.com>
Sent: Thursday, September 28, 2023 4:07 PM
To: Rob Barton
Subject: RE: ceramic burners for Caesars

Rob,

It's important to distinguish the difference between "5 PPM NOx corrected to 3% O2" and operation of the burner at 3% O2.

- ALZETA's CSB burner will operate at approximately 9.0% O2 (dry) with no FGR to maintain 5 PPM NOx.
  - **Uncorrected** emissions will be approximately 3.3 PPM NOx, as measured at 9.0% O2
  - **Corrected** emissions at 3% O2 will be 5 PPM NOx, in accordance with typical air quality rules in California and beyond
- With FGR, ALZETA's burners are capable of operating at approximately 6.0% O2 (dry), while maintaining NOx emissions of 5 PPM **corrected to** 3% O2
- For reference, ALZETA's CSB burners cannot operate at 3% O2 – this condition is too rich to maintain the integrity of the burner surface.

We can guarantee 5 PPM NOx **Corrected to** 3% O2, when operating at approximately 9% O2 without FGR. Let me know if you have any other questions.

Regards,

Justin Legg
Product Development Engineer
ALZETA Corporation
408-727-8282 x355
jlegg@alzeta.com

Office # 919-845-1422 ext. 24
Cell # 919-308-7701

From: Rob Barton
Sent: Monday, September 25, 2023 4:48 PM
To: Justin Legg <jlegg@alzeta.com>
Cc: Gary McCutchen <g.mccutchen@rtpenv.com>
Subject: RE: ceramic burners for Caesars

Hi Justin,

Thanks again for providing this information. One quick follow-up question:

Gary mentions the Cleaver-Brooks CBLE is able to be ordered in 60, 30, 9, or 5 ppm NOx configurations. The CSB is capable of meeting all of those emissions limits, depending on how much excess air is used.

Does this mean you can provide a performance guarantee for a CSB100 in a 5 ppm configuration at 3% O2? If not, what is the lowest NOx level the burner is capable of with and without FGR at 3% O2?

Rob

Rob Barton
RTP Environmental Associates, Inc.
304-A West Millbrook Road
Raleigh, NC 27609
Office # 919-845-1422 ext. 24
Cell # 919-308-7701

From: Justin Legg <jlegg@alzeta.com>
Sent: Wednesday, August 30, 2023 2:17 PM
To: Rob Barton <barton@rtpenv.com>
Cc: Gary McCutchen <g.mccutchen@rtpenv.com>
Subject: RE: ceramic burners for Caesars

Hi Rob,

I wanted to respond regarding an 86 MMBTU/hr burner for the Nebraska watertube Boiler, and also address some of Gary's earlier questions:

- Yes, the CSB1000 is very feasible for a water-tube boiler retrofit (note also that ALZETA's commercial agreements *do allow* us to supply CSB burners directly for water-tube boiler applications)
    - For background, ALZETA has been supplying CSB metal-mesh type burners since the early 2000s. Our first commercial installation was for a 126 MMBTU/hr O-Type boiler, and we have dozens of installations watertube installations, primarily throughout California.
- Regarding performance:
    - For a surface-stabilized metal mesh burner, NOx is primarily a function of excess air. The surface stabilization, combined with premixing, allows for the burner to operate at leaner conditions than other commercial burners. This lowers the flame temperature, reducing thermal NOx.
    - As such, the CSB can be tuned for different NOx requirements. Gary mentions the Cleaver-Brooks CBLE is able to be ordered in 60, 30, 9, or 5 ppm NOx configurations. The CSB is capable of meeting *all* of those emissions limits, depending on how much excess air is used. The CSB also a low emitter of CO (typically single-digit for the above NOx requirements)

- For longevity of the burner element, an excess air amount of 50% or more is ideal. This would result in approximately 15 PPM NOx (dry, corrected to 3% O2)
- Where efficiency is a concern, FGR can be used to lower the flame temperature; by substituting excess air with FGR and maintaining a constant amount of "dilution," NOx performance can be attained at *lower* amounts of excess air (i.e. 25% instead of 50%). **However,** FGR results in additional capital costs in order to accommodate the higher temperatures

- Regarding costs:
  - For an 86 MMBTU/hr CSB *without* FGR, budgetary cost for the equipment is roughly $360,000
  - Lifespan of a burner element is dependent on maintenance/operating conditions. Assuming proper maintenance of the unit, I'd estimate a 10-15 year lifespan; a full replacement element would be roughly $60,000.
  - Maintenance costs would only be related to air filtration. ALZETA uses large polyester industrial panel filters. The panels themselves are cleanable/washable up to 3 times, and there are also washable pre-filters available. Costs related to tuning would be minimal, as tuning is again related to maintaining proper excess air.

Regards,

Justin Legg
Product Development Engineer
ALZETA Corporation
408-727-8282 x355
jlegg@alzeta.com

From: Rob Barton [mailto:barton@rtpenv.com]
Sent: Friday, August 11, 2023 8:48 PM
To: jlegg@alzeta.com
Cc: Gary McCutchen
Subject: RE: ceramic burners for Caesars

Justin,

One more question… what is the lifespan of these burners? Based on our previous conversation, the estimated life of the ceramic fiber burners was about 10 years. I was wondering if the novel design was also associated with a similar lifespan.

Thanks!
Rob

Rob Barton
RTP Environmental Associates, Inc.
304-A West Millbrook Road
Raleigh, NC 27609
Office # 919-845-1422 ext. 24
Cell # 919-308-7701

From: Rob Barton
Sent: Friday, August 11, 2023 11:40 PM
To: jlegg@alzeta.com
Cc: Gary McCutchen <g.mccutchen@rtpenv.com>
Subject: RE: ceramic burners for Caesars

Justin,

Gary McCutchen (see thread below) mentioned the possibility of a metal mesh burner retrofit for existing watertube boilers. I had a similar question regarding feasibility and cost for a Nebraska watertube package boiler (Model NOX 2A/S-55) with a rated heat input of 86 MMBtu/hr. Can you confirm whether the CSB1000 might be a suitable replacement for the existing burner? If so, can you please provide a budgetary cost estimate for this burner and estimated level of performance with and without FGR?

Thank you!
Rob

Rob Barton
RTP Environmental Associates, Inc.
304-A West Millbrook Road
Raleigh, NC 27609
Office # 919-845-1422 ext. 24
Cell # 919-308-7701

From: Gary McCutchen <g.mccutchen@rtpenv.com>
Sent: Thursday, August 10, 2023 8:06 AM
To: Justin Legg <jlegg@alzeta.com>
Subject: FW: ceramic burners for Caesars

Justin, this is really interesting and useful. I didn't find (or notice) this type of burner as an option when I was doing the Reasonably Available Control Technology (RACT) determinations. The agency (Clark County, NV) where Caesars is located has to apply RACT to major sources per the Clean Air Act, so is looking into the costs (a technology can be rejected, as you probably know, if the cost-effectiveness is too high) of retrofitting natural gas fired boilers, like those at Caesars, to reduce NOx emissions.

This leads me to a couple of additional questions, which I hope you will be able to answer:

- Can this CSB burner be retrofit on existing boilers, especially those at Caesars and MGMRI? The Caesars and MGMRI boilers are summarized in these excerpts from the RACT report:
  - Caesars owns and operates five boilers (EUs: CP01–CP05) subject to NO_x RACT review. Each boiler is located at Caesars Palace and is approximately 34–35 MMBtu/hr in size. These boilers are classified as industrial, commercial, or institutional boilers because they include steam and hot water generators with heat input capacities from 0.4 to 1,500 MMBtu/hr.[1] According to the Caesars RACT analysis, the Hurst and Burnham boilers are 3-pass fire-tube, 800-bhp boilers; the existing Riello burners associated with all five boilers include LNB designs and cannot be modified to increase NO_x reduction to the level of ULNB capability. Caesars uses these boilers more than emergency generators or boilers at other Caesars properties, although they still are small emitters, with actual emissions of less than 3 tpy. All the boilers fire natural gas and have NO_x emissions limits of 29–30 ppm at 3% O_2. There are no limits on fuel use or operating hours
  - For MGMRI: The process equipment consists of two natural gas-fired boilers, each with a capacity of 32.66 MMBtu/hr, and 46 diesel-fired emergency generators that range from 1,100–3,700 hp. The boilers are classified as Commercial/Institutional (< 100 MMBtu/hr) and the engines as Large Internal Combustion Engines (> 500 hp). The two Cleaver Brooks boilers (MG13 and 14), which are Model CBLE series, are permitted to use only natural gas. According to the manufacturer's website, the CBLE are high-efficiency fire-tube boilers that can be ordered to achieve less than 60, 30, 9, or 5 ppm NO_x.[2] The permitted limit of 40 ppm at 3% O_2 is higher than the more common 30 ppm limit for LNB boilers.
- If retrofits are possible for one or more of these boilers, could you estimate the cost of retrofitting and operating them? In terms of operating costs, we're looking at whether there would be increased or decreased

maintenance, fuel use, etc., compared to the current burners. (When I thought ceramic burners were feasible, they had a fuel savings, which was important to their being considered affordable.) The most important cost figure is the retrofit cost. The costs don't have to be exact—even a general estimate would help, since I don't think I'm going to be able to find much cost information online.

Justin, I really appreciate the information you've provided and would very much appreciate any information you can provide on the above questions. The County was quite interested in this technology when I discussed it with them.

Gary McCutchen

Principal, RTP Environmental Associates, Inc.
g.mccutchen@rtpenv.com
(919) 395-9596 (mobile)
(775) 969-3616 (office)
18900 Fetlock Drive, Reno, NV 89508

From: Justin Legg <jlegg@alzeta.com>
Sent: Tuesday, August 8, 2023 11:35 AM
To: Gary McCutchen <g.mccutchen@rtpenv.com>
Subject: RE: ceramic burners for Caesars

Hi Gary,

Yes, we develop and manufacture surface-stabilized metal mesh burners. NOx emissions are 15 PPMV Dry, corrected to 3% O2 and lower. This is a technology that is well established in boiler applications, particularly in California's air quality districts (including South Coast Air Quality Management District). They are commercially available between 2 MMBTU/hr and 130 MMBTU/hr (I've attached a brochure for our commercial product, the CSB). For Firetube boilers specifically, they are manufactured by our partner company, Powerflame, as their "NVC" product.

Regards,

Justin Legg
Product Development Engineer
ALZETA Corporation
408-727-8282 x355
jlegg@alzeta.com

From: Gary McCutchen [mailto:g.mccutchen@rtpenv.com]
Sent: Monday, August 07, 2023 6:57 PM
To: Justin Legg
Subject: RE: ceramic burners for Caesars

Thanks very much for the confirmation and information. If I could bother you one more time, your statement about surface-stabilized metal mesh-type burners intrigued me. Do you make them and/or do you know what size they go up to and what the NOx emissions rate is? Can they get down to 10-15 MM Btu/hr NOx.

Gary McCutchen

Principal, RTP Environmental Associates, Inc.
g.mccutchen@rtpenv.com

(919) 395-9596 (mobile)
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18900 Fetlock Drive, Reno, NV 89508

From: Justin Legg <jlegg@alzeta.com>
Sent: Monday, August 7, 2023 5:08 PM
To: Gary McCutchen <g.mccutchen@rtpenv.com>
Subject: RE: ceramic burners for Caesars

Hi Gary,

- Yes, I can confirm that the e-mail to Russell Harns at Broadbent was sent by me.
- We are not aware of any applications larger than 16 MMBTU/hr for ceramic fiber burners.
- We are not aware of any research regarding ceramic burners on boilers or other large combustion devices.
- The problem with Caesars is size. We no longer build large radiant ceramic fiber burners as large as 16 MMBTU/hr; our current largest burner is in the 3 MMBTU/hr range, and these types of burners are typically applied to small hydronic/hot water boilers.
    - Please also note that large ceramic fiber burners have been replaced by surface-stabilized metal mesh-type burners, which are capable of 16 MMBTU/hr and larger.

Regards,

Justin Legg
Product Development Engineer
ALZETA Corporation
408-727-8282 x355
jlegg@alzeta.com

From: Gary McCutchen [mailto:g.mccutchen@rtpenv.com]
Sent: Saturday, August 05, 2023 2:15 PM
To: jlegg@alzeta.com
Subject: ceramic burners for Caesars
Importance: High

Hi Justin,

I'm assisting the Clark County air agency in determining appropriate retrofit control technologies for major sources of air pollution in the area. Caesars has forwarded to the County an email from you indicating that their firetube boilers are too large (30+ MM Btu/hr) for such burners. Based on that information, we conducted an online search for size limits and found information indicating that the largest commercial applications for such burners is about 16 MM Btu/hr, which of course agrees with your statement.

We're still pretty impressed with this technology and are interested in the types of sources that could apply it. If you wouldn't mind, I'd appreciate if you could take a few minutes to clarify the following:

- That the following email to Caesars was indeed from you:

  "Hi Russell,
  Based on the information you've provided, we believe that "ceramic burners" are not the appropriate technology for a firetube boiler application. They are only intended for low heat-flux applications, and a ceramic fiber burner for a 30 MMBTU/hr boiler application would be too large to be practical." Let me know if you have any other questions.

Regards,
Justin Legg
Product Development Engineer
ALZETA Corporation"

- Whether you are aware of any applications on boilers or other sources greater than 16 MM Btu/hr.
- Whether you're aware of any research regarding ceramic burner applications on larger boilers or other combustion devices.
- Whether the problem for the Caesars boilers is only the size; in other words, are ceramic burners workable for smaller firetube boilers or can the design of firetube boilers also be a problem (especially for retrofit situations)?

Thank you very much for any assistance you can provide.

Gary McCutchen

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[1] EPA-453/R-94-022, Alternative Control Techniques Document—NO_x Emissions from Industrial/Commercial/Institutional (ICI) Boilers, March 1994, p. 1-1.

[2] MGMRI's OP limits the two boilers to 40 ppm NOx at 3% O2: "The permittee shall operate and maintain each of the boilers with burners that have a manufacturer's maximum emission concentration of 40 ppmv NOx, corrected to 3% oxygen (EUs: MG01, MG02, MG05, MG06, MG13, MG14, and MG16)." Condition III.A.5.c.

Appendix 9

DAQ Detailed Cost Calculations

COST EFFECTIVENESS CALCULATION 1	
NELLIS AIR FORCE BASE (NAFB)	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
SELECTIVE CATALYTIC REDUCTION (SCR)	
Emissions Unit/Control Technology	
Emissions Unit	Unit A032
Emission Unit Description	Non-emergency generator
Pollutant	NOx
Control Technology	SCR
Baseline Emissions Rate (tpy)	0.39
Emissions Reduction (%)	90
Controlled Emissions (tpy)	0.039
Annualized Capital Costs	
Initial Capital Investment+A15	$100,000
Direct & Indirect Costs	$15,340
Total Capital Investment	$115,340
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$8,379
Annual Operating Costs	
Urea	$595
Catalyst	$1,013
Maintenance	$3,000
Total Annualized Cost	$12,987
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.351
Cost Effectiveness ($/ton)	$37,001

Note:
Highest rate in most recent 5 years

Note:
90% reduction with SCR indicated in literature and WW Williams quote for Caesars

Note:
Based on quotes from WW Williams in Caesars RACT of $119,571, then adjusted down for smaller unit

Note:
From Caesars based on quote from WW Williams

Note:
All costs from Caesars, except maintenance cut to $3K from $6K assuming lower due to # of generators at site.

COST EFFECTIVENESS CALCULATION 2	
NELLIS AIR FORCE BASE (NAFB)	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
DUAL FUEL	
Emissions Unit/Control Technology	
Emissions Unit	Unit A032
Emission Unit Description	Non-emergency generator
Pollutant	NOx
Control Technology	Dual Fuel
Baseline Emissions Rate (tpy)	0.39
Emissions Reduction (%)	30
Controlled Emissions (tpy)	0.273
Annualized Capital Costs	
Initial Capital Investment	$8,000
Direct & Indirect Costs	$2,000
Total Capital Investment	$10,000
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$727
Annual Operating Costs	
Maintenance	
Total Annualized Cost	$727
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.117
Cost Effectiveness ($/ton)	$6,209

Note:
Highest rate in most recent 5 years

Note:
20-30% from lab tests on direct-injection motor. West Virginia thesis.

Note:
Based on ranges for engines with and without turbocharging. See: https://finddiffer.com/how-much-does-it-cost-to-convert-a-diesel-engine-to-gas/

Note:
Assumed cost for hooking up to natural gas

Note:
Using natural gas could save money, depending on relative fuel prices and maintenace is expected to be less than with diesel due to less wear, but slightly higher due to dual system, so likely no change.

COST EFFECTIVENESS CALCULATION 3	
NELLIS AIR FORCE BASE (NAFB)	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
MANIFOLD AIR TEMPERATURE (MAT) REDUCTION	
Emissions Unit/Control Technology	
Emissions Unit	Unit A032
Emission Unit Description	Non-emergency generator
Pollutant	NOx
Control Technology	MAT
Baseline Emissions Rate (tpy)	0.39
Emissions Reduction (%)	70
Controlled Emissions (tpy)	0.117
Annualized Capital Costs	
Initial Capital Investment	$10,000
Direct & Indirect Costs	$5,000
Total Capital Investment	$15,000
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$1,090
Annual Operating Costs	
Maintenance	$3,000
Total Annualized Cost	$4,090
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.273
Cost Effectiveness ($/ton)	$14,981

Note:
Highest rate in most recent 5 years

Note:
70% reduction based on formula from 1978 EPA Control Techniques document, Table 4-20, and Komatsu report on an air-cooled aftercooler that lowered inlet air from 356 to 122 F

Note:
Based on internet search indicating an aftercooler costing $5000-7000, but that's just the unit and does not include the piping and other hardware, so selected $10,000.

Note:
Assumed cost to install system.

Note:
Assumes this is the additional cost of maintenance.

COST EFFECTIVENESS CALCULATION 4	
NELLIS AIR FORCE BASE (NAFB)	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
DIRECT WATER INJECTION (DWI)	
Emissions Unit/Control Technology	
Emissions Unit	Unit A032
Emission Unit Description	Non-emergency generator
Pollutant	NOx
Control Technology	DWI
Baseline Emissions Rate (tpy)	0.39
Emissions Reduction (%)	60
Controlled Emissions (tpy)	0.156
Annualized Capital Costs	
Initial Capital Investment	$8,370
Direct & Indirect Costs	
Total Capital Investment	$8,370
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$608
Annual Operating Costs	
Maintenance	$3,000
Total Annualized Cost	$3,608
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.234
Cost Effectiveness ($/ton)	$15,419

Note:
Highest rate in most recent 5 years

Based on Issa article

Note:
Based on Issa article, which gave costs in $/kW for 6000 to 64,000 HP. Includes cost to adapt injection to existing engines.

Note:
Assumes this is the additional cost of maintenance.

COST EFFECTIVENESS CALCULATION 5	
NELLIS AIR FORCE BASE (NAFB)	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
EMULSIFIED DIESEL	
Emissions Unit/Control Technology	
Emissions Unit	Unit A032
Emission Unit Description	Non-emergency generator
Pollutant	NOx
Control Technology	EMULSIFIED DIESEL
Baseline Emissions Rate (tpy)	0.39
Emissions Reduction (%)	20
Controlled Emissions (tpy)	0.312
Annualized Capital Costs	
Initial Capital Investment	$4,650
Direct & Indirect Costs	
Total Capital Investment	$4,650
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$338
Annual Operating Costs	
Fuel cost difference ($0.22/gallon, 6724 gal/year at 500 hr/yr	$1,479
Maintenance	$3,000
Total Annualized Cost	$4,817
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.078
Cost Effectiveness ($/ton)	$61,754

Note:
Highest rate in most recent 5 years

Based only 10% water in emulsion. Can go higher in water and reduce NOx more, but stability of emulsion decreased rapidly with additonal water.

Note:
Based on $25/kW capital costs.

Note:
Assumes this is the additional cost of maintenance.

COST EFFECTIVENESS CALCULATION 6	
NELLIS AIR FORCE BASE (NAFB)	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
SELECTIVE CATALYTIC REDUCTION (SCR)	
Emissions Unit/Control Technology	
Emissions Unit	Unit G041
Emission Unit Description	Non-emergency generator
Pollutant	NOx
Control Technology	SCR
Baseline Emissions Rate (tpy)	1.861
Emissions Reduction (%)	90
Controlled Emissions (tpy)	0.1861
Annualized Capital Costs	
Initial Capital Investment	$100,000
Direct & Indirect Costs	$15,340
Total Capital Investment	$115,340
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$8,379
Annual Operating Costs	
Urea	$595
Catalyst	$1,013
Maintenance	$3,000
Total Annualized Cost	$12,987
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.6749
Cost Effectiveness ($/ton)	$7,754

Note:
Highest rate in most recent 5 years

Note:
90% reduction with SCR indicated in literature and WW Williams quote for Caesars

Note:
Based on quotes from WW Williams in Caesars RACT of $119,571, then adjusted down for smaller unit

Note:
From Caesars based on quote from WW Williams

Note:
All costs from Caesars, except maintenance cut to $3K from $6K assuming lower due to # of generators at site.

COST EFFECTIVENESS CALCULATION 7	
NELLIS AIR FORCE BASE (NAFB)	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
INJECTION TIMING RETARD (ITR)	
Emissions Unit/Control Technology	
Emissions Unit	Unit G041
Emission Unit Description	Emergency generator
Pollutant	NOx
Control Technology	ITR
Baseline Emissions Rate (tpy)	1.861
Emissions Reduction (%)	30
Controlled Emissions (tpy)	1.3027
Annualized Capital Costs	
Initial Capital Investment	$16,000
Direct & Indirect Costs	
Total Capital Investment	$16,000
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$1,162
Annual Operating Costs	
Other	$16,000
Maintenance	
Total Annualized Cost	$17,162
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.5583
Cost Effectiveness ($/ton)	$30,740

Note:
Highest rate in most recent 5 years

Note:
20-30% estimated in EPA ACT, p. 2-18, for CI diesels. Used 30%.

Note:
NAFB used 10 years but no justification, so defaulted to 30 years

Note:
Based on ACT costs, p. 2-42, for a 2000 HP engine. Range is $16-24K for capital cost, $16-32K annual cost.

COST EFFECTIVENESS CALCULATION 8	
NELLIS AIR FORCE BASE (NAFB)	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
MANIFOLD AIR TEMPERATURE (MAT) REDUCTION	
Emissions Unit/Control Technology	
Emissions Unit	Unit G041
Emission Unit Description	Emergency generator
Pollutant	NOx
Control Technology	MAT
Baseline Emissions Rate (tpy)	1.861
Emissions Reduction (%)	70
Controlled Emissions (tpy)	0.5583
Annualized Capital Costs	
Initial Capital Investment	$10,000
Direct & Indirect Costs	$5,000
Total Capital Investment	$15,000
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$1,090
Annual Operating Costs	
Maintenance	$3,000
Total Annualized Cost	$4,090
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.3027
Cost Effectiveness ($/ton)	$3,139

Note:
Highest rate in most recent 5 years

Note:
70% reduction based on formula from 1978 EPA Control Techniques document, Table 4-20, and Komatsu report on an air-cooled aftercooler that lowered inlet air from 356 to 122 F

Note:
Based on internet search indicating an aftercooler costing $5000-7000, but that's just the unit and does not include the piping and other hardware, so selected $10,000.

Note:
Assumed cost to install system.

Note:
Assumes this is the additional cost of maintenance.

COST EFFECTIVENESS CALCULATION 9	
NELLIS AIR FORCE BASE (NAFB)	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
Direct Water Injection (DWI)	
Emissions Unit/Control Technology	
Emissions Unit	Unit A032
Emission Unit Description	Non-emergency generator
Pollutant	NOx
Control Technology	DWI
Baseline Emissions Rate (tpy)	1.861
Emissions Reduction (%)	35
Controlled Emissions (tpy)	1.20965
Annualized Capital Costs	
Initial Capital Investment	$37,510
Direct & Indirect Costs	
Total Capital Investment	$37,510
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$2,725
Annual Operating Costs	
Maintenance	$3,000
Total Annualized Cost	$5,725
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.65135
Cost Effectiveness ($/ton)	$8,790

Note:
Highest rate in most recent 5 years

Based on Issa article

Note:
Based on Issa article, which gave costs in $/kW for 6000 to 64,000 HP. Includes cost to adapt injection to existing engines.

Note:
Assumes this is the additional cost of maintenance.

COST EFFECTIVENESS CALCULATION 10	
NELLIS AIR FORCE BASE (NAFB)	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
Direct Water Injection (DWI)	
Emissions Unit/Control Technology	
Emissions Unit	Unit A032
Emission Unit Description	Non-emergency generator
Pollutant	NOx
Control Technology	DWI
Baseline Emissions Rate (tpy)	1.861
Emissions Reduction (%)	50
Controlled Emissions (tpy)	0.9305
Annualized Capital Costs	
Initial Capital Investment	$21,840
Direct & Indirect Costs	
Total Capital Investment	$21,840
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$1,587
Annual Operating Costs	
Fuel cost difference ($0.22/gallon, 6724 gal/year at 500 hr/yr	$7,810
Maintenance	$3,000
Total Annualized Cost	$12,397
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.9305
Cost Effectiveness ($/ton)	$13,323

Note:
Highest rate in most recent 5 years

Based only 10% water in emulsion. Can go higher in water and reduce NOx more, but stability of emulsion decreased rapidly with additonal water.

Note:
Based on $24/kW capital costs.

Note:
Assumes this is the additional cost of maintenance.

COST EFFECTIVENESS CALCULATION 11	
NELLIS AIR FORCE BASE (NAFB)	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
Dual Fuel	
Emissions Unit/Control Technology	
Emissions Unit	Unit A032
Emission Unit Description	Non-emergency generator
Pollutant	NOx
Control Technology	Dual Fuel
Baseline Emissions Rate (tpy)	1.861
Emissions Reduction (%)	30
Controlled Emissions (tpy)	1.3027
Annualized Capital Costs	
Initial Capital Investment	$21,840
Direct & Indirect Costs	$2,000
Total Capital Investment	$23,840
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$1,732
Annual Operating Costs	
Maintenance	$3,000
Total Annualized Cost	$4,732
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.5583
Cost Effectiveness ($/ton)	$8,476

Note:
Highest rate in most recent 5 years

Note:
Assumes 30% control

Note:
Based on ranges for engines with and without turbocharging. See: https://finddiffer.com/how-much-does-it-cost-to-convert-a-diesel-engine-to-gas/

Note:
Assumed cost for hooking up to natural gas

Note:
Using natural gas could save money, depending on relative fuel prices and maintenace is expected to be less than with diesel due to less wear, but slightly higher due to dual system, so likely no change.

COST EFFECTIVENESS CALCULATION 12	
NELLIS AIR FORCE BASE (NAFB)	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
SELECTIVE CATALYTIC REDUCTION (SCR)	
Emissions Unit/Control Technology	
Emissions Unit	Hush House
Emission Unit Description	Hush House
Pollutant	NOx
Control Technology	SCR
Baseline Emissions Rate (tpy)	12.9
Emissions Reduction (%)	90
Controlled Emissions (tpy)	1.29
Annualized Capital Costs	
Initial Capital Investment	$1,410,811
Direct & Indirect Costs	$153,400
Total Capital Investment	$1,564,211
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$113,640
Annual Operating Costs	
Urea	$595
Catalyst	$1,013
Maintenance	$6,000
Total Annualized Cost	$121,248
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	11.61
Cost Effectiveness ($/ton)	$10,443

Note:
Highest rate in most recent 5 years

Note:
90% reduction with SCR indicated in literature and WW Williams quote for Caesars

Note:
Extrapolated from WW Wiliiams cost of $145K and ratio of 3700 HP diesel to 36,000 HP turbofan in afterburner mode.

Note:
From Caesars based on quote from WW Williams, scaled up by factor of 10

Note:
All costs from Caesars without scaleup.

COST EFFECTIVENESS CALCULATION 13	
CAESARS	
BOILERS	
ULTRA-LOW NOx BURNERS (LNB)	
Emissions Unit/Control Technology	
Emissions Unit	CP02
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	ULNB
Baseline Emissions Rate (tpy)	2.74
Emissions Reduction (%)	70
Controlled Emissions (tpy)	0.822
Annualized Capital Costs	
Initial Capital Investment	$235,000
Direct & Indirect Costs	$3,000
Total Capital Investment	$238,000
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$17,291
Annual Operating Costs	
Total Annualized Cost	$17,291
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.918
Cost Effectiveness ($/ton)	$9,015

Note:
From Caesars RACT analysis for CP02

Note:
From Caesars

Note:
Based on quotes from Caesars RACT

Note:
From Caesars

Note:
None estimated

COST EFFECTIVENESS CALCULATION 14	
CAESARS	
BOILERS	
FGR	
Emissions Unit/Control Technology	
Emissions Unit	CP02
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	FGR
Baseline Emissions Rate (tpy)	2.74
Emissions Reduction (%)	42
Controlled Emissions (tpy)	1.5892
Annualized Capital Costs	
Initial Capital Investment	$116,318
Direct & Indirect Costs	$3,000
Total Capital Investment	$119,318
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$8,668
Annual Operating Costs	
Total Annualized Cost	$8,668
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.1508
Cost Effectiveness ($/ton)	$7,533

Note:
From Caesars RACT analysis for CP02

Note:
From Caesars

Note:
Based on 1975 cost for retrofit from 1978 EPA Control Tech doc of $21K (p. 4-55), adjusted for inflation with inflation index to 2023 (2023/1975 = $16196/$2924)

Note: general estimate

Note:
None estimated

COST EFFECTIVENESS CALCULATION 15	
CAESARS	
BOILERS	
FGR	
Emissions Unit/Control Technology	
Emissions Unit	CP02
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	FGR
Baseline Emissions Rate (tpy)	2.74
Emissions Reduction (%)	42
Controlled Emissions (tpy)	1.5892
Annualized Capital Costs	
Initial Capital Investment	$94,920
Direct & Indirect Costs	$3,000
Total Capital Investment	$97,920
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$7,114
Annual Operating Costs	
Total Annualized Cost	$7,114
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.1508
Cost Effectiveness ($/ton)	$6,182

Note:
From Caesars RACT analysis for CP02

Note:
From Caesars

Note:
Based on 1975 cost for retrofit from 1978 EPA Control Tech doc of $21K (p. 4-55), adjusted with Chem Engr Cost Index (ratio = 824.5 (2022) / 182.4 (1975) = 4.52). 4.52x21,000 = $94,920

Note: general estimate

Note:
None estimated

COST EFFECTIVENESS CALCULATION 16	
CAESARS	
BOILERS	
ULNB/FGR	
Emissions Unit/Control Technology	
Emissions Unit	CP02
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	ULNB/FGR
Baseline Emissions Rate (tpy)	2.74
Emissions Reduction (%)	75
Controlled Emissions (tpy)	0.685
Annualized Capital Costs	
Initial Capital Investment	$77,200
Direct & Indirect Costs	
Total Capital Investment	$77,200
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$5,609
Annual Operating Costs	
General	$39,520
Total Annualized Cost	$45,129
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	2.055
Cost Effectiveness ($/ton)	$21,960

Note:
From Caesars RACT analysis for CP02

Note:
From MGM

Note:
Based on 1975 cost for retrofit from 1978 EPA From MGMRI RACT analysis

Note:
From MGMRI RACT analysis

COST EFFECTIVENESS CALCULATION 17	
CAESARS	
BOILERS	
Overfire Air (OFA)	
Emissions Unit/Control Technology	
Emissions Unit	CP02
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	OFA
Baseline Emissions Rate (tpy)	2.74
Emissions Reduction (%)	50
Controlled Emissions (tpy)	1.37
Annualized Capital Costs	
Initial Capital Investment	$116,318
Direct & Indirect Costs	$3,000
Total Capital Investment	$119,318
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$8,668
Annual Operating Costs	
Total Annualized Cost	$8,668
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.37
Cost Effectiveness ($/ton)	$6,327

Note:
From Caesars 2017 Emissions Inventor--
Highest actual emissions--Unit A11.

Note:
Based on 1975 cost for retrofit from 1978 EPA Control Tech doc of $21K (p. 4-55), adjusted for inflation with Chem Engr index to 2022 (2022/1975 = $824.5/182.4 = 4.52

Note: general estimate

Note:
None estimated

COST EFFECTIVENESS CALCULATION 18	
CAESARS	
BOILERS	
Fuel-Induced Recirculation (FIR2)	
Emissions Unit/Control Technology	
Emissions Unit	CP02
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	FIR2
Baseline Emissions Rate (tpy)	2.74
Emissions Reduction (%)	43
Controlled Emissions (tpy)	1.5618
Annualized Capital Costs	
Initial Capital Investment	$94,920
Direct & Indirect Costs	$3,000
Total Capital Investment	$97,920
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$7,114
Annual Operating Costs	
Total Annualized Cost	$7,114
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.1782
Cost Effectiveness ($/ton)	$6,038

Note:
From Caesars RACT analysis for CP02

Note:
From Caesars

Note:
Based on 1975 cost for retrofit from 1978 EPA Control Tech doc of $21K (p. 4-55), adjusted with Chem Engr Cost Index (ratio = 824.5 (2022)/182.4 (1975) = 4.52). 4.52x21,000 = $94,920

Note: general estimate

Note:
None estimated

COST EFFECTIVENESS CALCULATION 19	
CAESARS	
BOILERS	
Ceramic Fiber Burners (CFB)	
Emissions Unit/Control Technology	
Emissions Unit	CP04
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	CFB
Baseline Emissions Rate (tpy)	1.08
Emissions Reduction (%)	50
Controlled Emissions (tpy)	0.54
Annualized Capital Costs	
Initial Capital Investment	$36,235
Direct & Indirect Costs	$3,000
Total Capital Investment	$39,235
Estimated Equipment Life, years	10
Interest Rate, %	6
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$5,336
Annual Operating Costs	
5% fuel savings assuming 446.6 hr/year	
Total Annualized Cost	$5,336
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.54
Cost Effectiveness ($/ton)	$9,881

Note:
From Caesars RACT analysis for CP04

Note:
From Cost 2011

Note:
Based on cost of $0.78/M Btu (per 1000 Btu), 33 Mm Btu/hr burner, CEPCI = $824.5/585.7

Note: general estimate from Caesars analyses

Note:
CP02 emissions of 2.74 would give a CE of $3895/ton because of the additional tons of NOx captured

COST EFFECTIVENESS CALCULATION 20	
CAESARS	
BOILERS	
Ceramic Fiber Burners (CFB)	
Emissions Unit/Control Technology	
Emissions Unit	CP04
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	CFB
Baseline Emissions Rate (tpy)	1.08
Emissions Reduction (%)	50
Controlled Emissions (tpy)	0.54
Annualized Capital Costs	
Initial Capital Investment	$36,235
Direct & Indirect Costs	$3,000
Total Capital Investment	$39,235
Estimated Equipment Life, years	10
Interest Rate, %	6
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$5,336
Annual Operating Costs	
5% fuel savings assuming 446.6 hr/year	-$6,815
Total Annualized Cost	-$1,479
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.54
Cost Effectiveness ($/ton)	-$2,739

Note:
From Caesars RACT analysis for CP04

Note:
From Cost 2011

Note:
Based on cost of $0.78/M Btu (per 1000 Btu), 33 Mm Btu/hr burner, CEPCI = $824.5/585.7

Note: general estimate from Caesars analyses

Note:
Assumes natural gas at $9.25/1000 cubic feet and operation of the burner at full capacity (33 MM Btu/hr)

Note:
CP02 emissions of 2.74 would give a CE of (-$1080/ton captured)

COST EFFECTIVENESS CALCULATION 21	
CAESARS	
BOILERS	
Oxygen Trim (OT)	
Emissions Unit/Control Technology	
Emissions Unit	CP02
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	OT
Baseline Emissions Rate (tpy)	2.74
Emissions Reduction (%)	15
Controlled Emissions (tpy)	2.329
Annualized Capital Costs	
Initial Capital Investment	$7,596
Direct & Indirect Costs	$7,596
Total Capital Investment	$15,192
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$1,104
Annual Operating Costs	
	$2,000
Total Annualized Cost	$3,104
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.411
Cost Effectiveness ($/ton)	$7,552

Note:
From Caesars 2017 Emissions Inventor--Highest boiler emissions

Note:
From Guide, p. 5-5

Note:
Based on 1994 ACT cost in 1992 $ of $100/MM Btu/hr. This is $3300 for a 33 MM Btu/hr burner. Adjusted for inflation withChem Engr index to 2022 (2022/1992 = $824.5/$358.2 = 2.3, so $7596.

Note: Assumes same as capital cost

Note:
General estimate

COST EFFECTIVENESS CALCULATION 22	
CAESARS	
BOILERS	
Gas Fuel Flow Modifiers (GFFM)	
Emissions Unit/Control Technology	
Emissions Unit	CP02
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	GFFM
Baseline Emissions Rate (tpy)	2.74
Emissions Reduction (%)	15
Controlled Emissions (tpy)	2.329
Annualized Capital Costs	
Initial Capital Investment	$117,500
Direct & Indirect Costs	$3,000
Total Capital Investment	$120,500
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$8,754
Annual Operating Costs	
Total Annualized Cost	$8,754
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.411
Cost Effectiveness ($/ton)	$21,300

Note:
From Caesars RACT analysis for CP02

Note:
From ACT, mid-range value

Note:
Based on quotes from Caesars RACT for ULNB but reduced to half the ULNB cost since less equipment involved

Note:
From Caesars

Note:
None estimated

COST EFFECTIVENESS CALCULATION 23	
CAESARS	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
SELECTIVE CATALYTIC REDUCTION (SCR)	
Emissions Unit/Control Technology	
Emissions Unit	CP13 Group
Emission Unit Description	Emergency Generator
Pollutant	NOx
Control Technology	SCR
Baseline Emissions Rate (tpy)	1.04
Emissions Reduction (%)	90
Controlled Emissions (tpy)	0.104
Annualized Capital Costs	
Initial Capital Investment	$145,519
Direct & Indirect Costs	$15,340
Total Capital Investment	$160,859
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$11,686
Annual Operating Costs	
Urea	$1,666
Catalyst	$2,702
Maintenance	$6,000
Total Annualized Cost	$22,054
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.936
Cost Effectiveness ($/ton)	$23,562

Note:
From Caesars RACT analysis for the group of generators beginning with CP13.

Note:
90% reduction with SCR indicated in literature and WW Williams quote for Caesars

Note:
Based on quotes from WW Williams in Caesars RACT

Note:
From Caesars based on quote from WW Williams

Note:
All costs from Caesars, except maintenance cut to $3K from $6K assuming lower due to # of generators at site.

COST EFFECTIVENESS CALCULATION 24	
CAESARS	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
INJECTION TIMING RETARD (ITR)	
Emissions Unit/Control Technology	
Emissions Unit	CP13 GROUP
Emission Unit Description	Emergency generator
Pollutant	NOx
Control Technology	ITR
Baseline Emissions Rate (tpy)	1.04
Emissions Reduction (%)	30
Controlled Emissions (tpy)	0.728
Annualized Capital Costs	
Initial Capital Investment	$16,000
Direct & Indirect Costs	
Total Capital Investment	$16,000
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$1,162
Annual Operating Costs	
Other	$920
Maintenance	
Total Annualized Cost	$2,082
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.312
Cost Effectiveness ($/ton)	$6,674

Note:
From Caesars RACT analysis for the group of generators beginning with CP13.

Note:
20-30% estimated in EPA ACT, p. 2-18, for CI diesels. Used 30%.

Note:
Based on ACT costs, p. 2-42, for a 2501-4000 HP engine. Range is $24K for capital cost, $32-46K annual cost in 1993 $; this value is adjusted per the CEPCI to 2022 $. Annualized cost from the ACT seems high but llikely reflects the 0-5% fuel penalty, so the 8000 hour adjusted cost of $73,600 is adjusted down to 100 hr/year operation allowed, which is $920/year.

COST EFFECTIVENESS CALCULATION 25	
CAESARS	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
Direct Water Injection (DWI)	
Emissions Unit/Control Technology	
Emissions Unit	CP13 GROUP
Emission Unit Description	Emergency Generator
Pollutant	NOx
Control Technology	DWI
Baseline Emissions Rate (tpy)	1.04
Emissions Reduction (%)	60
Controlled Emissions (tpy)	0.416
Annualized Capital Costs	
Initial Capital Investment	$94,533
Direct & Indirect Costs	
Total Capital Investment	$94,533
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$6,868
Annual Operating Costs	
2-3% Fuel Penalty	
Other	
Maintenance	
Total Annualized Cost	$6,868
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.624
Cost Effectiveness ($/ton)	$11,006

Note:
Highest rate in most recent 5 years

Based on Issa article

Note:
Based on Issa article, which gave costs in $/kW for 6000 to 64,000 HP. Includes cost to adapt injection to existing engines. Extrapolated cost to smaller 2100 kW engine to get $45/kW.

Note:
Did not calculate cost of fuel penalty or increased maiintenance.

COST EFFECTIVENESS CALCULATION 26	
CAESARS	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
Direct Water Injection (DWI)	
Emissions Unit/Control Technology	
Emissions Unit	CP13 Group
Emission Unit Description	Non-emergency generator
Pollutant	NOx
Control Technology	DWI
Baseline Emissions Rate (tpy)	1.04
Emissions Reduction (%)	50
Controlled Emissions (tpy)	0.52
Annualized Capital Costs	
Initial Capital Investment	$46,200
Direct & Indirect Costs	
Total Capital Investment	$46,200
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$3,356
Annual Operating Costs	
Fuel cost difference ($0.22/gallon, 6724 gal/year at 500 hr/yr	$3,122
Maintenance	
Total Annualized Cost	$6,478
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.52
Cost Effectiveness ($/ton)	$12,459

Note:
From Caesars RACT analysis

Based only 10% water in emulsion. Can go higher in water and reduce NOx more, but stability of emulsion decreased rapidly with additonal water.

Note:
Based on $22d/kW capital costs.

COST EFFECTIVENESS CALCULATION 27	
CAESARS	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
Dual Fuel	
Emissions Unit/Control Technology	
Emissions Unit	CP13 GROUP
Emission Unit Description	Non-emergency generator
Pollutant	NOx
Control Technology	Dual Fuel
Baseline Emissions Rate (tpy)	1.04
Emissions Reduction (%)	26.5
Controlled Emissions (tpy)	0.7644
Annualized Capital Costs	
Initial Capital Investment	$24,000
Direct & Indirect Costs	$2,000
Total Capital Investment	$26,000
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$1,889
Annual Operating Costs	
Maintenance	$3,000
Total Annualized Cost	$4,889
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.2756
Cost Effectiveness ($/ton)	$17,739

Note:
From Caesars report

Note:
From 1993 ACT, p. 2-3, Table 2-1. For 2001-4000 HP, diesel = 830 ppmv, dual = 610 ppmv, so 26.5% reduction.

Note:
Based on ranges for engines with and without turbocharging. See: https://finddiffer.com/how-much-does-it-cost-to-convert-a-diesel-engine-to-gas/ Note that this is for small truck engines and, with turbochargers, assumes $8-12K conversioin charge, so assume double the $12K for the large engine.

Note:
Assumed cost for hooking up to natural gas

Note:
Using natural gas could save money, depending on relative fuel prices and maintenace is expected to be less than with diesel due to less wear, but slightly higher due to dual system, so likely no change.

COST EFFECTIVENESS CALCULATION 28	
SWITCH	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
SELECTIVE CATALYTIC REDUCTION (SCR)	
Emissions Unit/Control Technology	
Emissions Unit	NA
Emission Unit Description	emergency generator
Pollutant	NOx
Control Technology	SCR
Baseline Emissions Rate (tpy)	1.16
Emissions Reduction (%)	90
Controlled Emissions (tpy)	0.116
Annualized Capital Costs	
Initial Capital Investment	$145,519
Direct & Indirect Costs	$15,340
Total Capital Investment	$160,859
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$11,686
Annual Operating Costs	
Urea	$1,666
Catalyst	$2,702
Maintenance	$6,000
Total Annualized Cost	$22,054
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.044
Cost Effectiveness ($/ton)	$21,125

Note:
This is total emissions from the entire source, per the RACT Guidance, p. 7), but there are around 100 generators.

Note:
90% reduction with SCR indicated in literature and WW Williams quote for Caesars

Note:
Based on quotes from WW Williams in Caesars RACT

Note:
From Caesars based on quote from WW Williams

Note:
All costs from Caesars.

COST EFFECTIVENESS CALCULATION 29	
MGMRI	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
Dual Fuel	
Emissions Unit/Control Technology	
Emissions Unit	MG17
Emission Unit Description	Emergency generator
Pollutant	NOx
Control Technology	Dual Fuel
Baseline Emissions Rate (tpy)	3.49
Emissions Reduction (%)	26.5
Controlled Emissions (tpy)	2.56515
Annualized Capital Costs	
Initial Capital Investment	$24,000
Direct & Indirect Costs	$2,000
Total Capital Investment	$26,000
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$1,889
Annual Operating Costs	
Maintenance	$3,000
Total Annualized Cost	$4,889
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.92485
Cost Effectiveness ($/ton)	$5,286

Note:
Nelllis AFB actual emissions % of NAFB PTE (Unit 41) PTE = 8.07 tpy, actual max= 1.861, so 23.1% of 15.12 = 3.49

Note:
From 1993 ACT, p. 2-3, Table 2-1. For 2001-4000 HP, diesel = 830 ppmv, dual = 610 ppmv, so 26.5% reduction.

Note:
Based on ranges for engines with and without turbocharging. See: https://finddiffer.com/how-much-does-it-cost-to-convert-a-diesel-engine-to-gas/ Note that this is for small truck engines and, with turbochargers, assumes $8-12K conversioin charge, so assume double the $12K for the large engine.

Note:
Assumed cost for hooking up to natural gas

Note:
Using natural gas could save money, depending on relative fuel prices and maintenace may even be less than with diesel due to less wear, so assume general additional maintenance of $3K

COST EFFECTIVENESS CALCULATION 30	
MGMRI	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
Direct Water Injection (DWI)	
Emissions Unit/Control Technology	
Emissions Unit	Unit MG17
Emission Unit Description	Emergency generator
Pollutant	NOx
Control Technology	DWI
Baseline Emissions Rate (tpy)	3.49
Emissions Reduction (%)	50
Controlled Emissions (tpy)	1.745
Annualized Capital Costs	
Initial Capital Investment	$55,440
Direct & Indirect Costs	
Total Capital Investment	$55,440
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$4,028
Annual Operating Costs	
Fuel cost difference ($0.22/gallon, 16,389 gal/year at 115.1 hr/yr	$7,810
Maintenance	$3,000
Total Annualized Cost	$14,838
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.745
Cost Effectiveness ($/ton)	$8,503

Note:
Nelllis AFB actual emissions % of NAFB PTE (Unit 41) PTE = 8.07 tpy, actual max= 1.861, so 23.1% of 15.12 = 3.49

Based only 10% water in emulsion. Can go higher in water and reduce NOx more, but stability of emulsion decreased rapidly with additonal water.

Note:
Based on $24/kW capital costs.

Note:
Based on operation 23.1% of allowed 500 hours and use of 141.9 gal/hr at full load

Note:
Assumes this is the additional cost of maintenance.

COST EFFECTIVENESS CALCULATION 31	
MGMRI	
BOILERS	
ULTRA-LOW NOx BURNERS (LNB)	
Emissions Unit/Control Technology	
Emissions Unit	MG13
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	ULNB
Baseline Emissions Rate (tpy)	1.66
Emissions Reduction (%)	77
Controlled Emissions (tpy)	0.3818
Annualized Capital Costs	
Initial Capital Investment	$235,000
Direct & Indirect Costs	
Total Capital Investment	$235,000
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$17,073
Annual Operating Costs	
Total Annualized Cost	$17,073
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.2782
Cost Effectiveness ($/ton)	$13,357

Note:
From MGMRI RACT analysis TAble 2-1.

Note:
MGMRI has 40 ppm LNB already on. ULNB burner quoted can get to 9 ppm, so about 77% reduction.

Note:
Based on quotes from Pyro Combustion Controls for a ULNB burner for Caesars boilers (in the Caesars RACT analysis).

Note:
None estimated

COST EFFECTIVENESS CALCULATION 32	
MGMRI	
BOILERS	
FGR	
Emissions Unit/Control Technology	
Emissions Unit	MG13
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	FGR
Baseline Emissions Rate (tpy)	1.66
Emissions Reduction (%)	35.69
Controlled Emissions (tpy)	1.067546
Annualized Capital Costs	
Initial Capital Investment	$77,200
Direct & Indirect Costs	
Total Capital Investment	$77,200
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$5,609
Annual Operating Costs	
Total Annualized Cost	$5,609
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.592454
Cost Effectiveness ($/ton)	$9,467

Note:
From MGMRI RACT analysis Table 2-1

Note:
From MGMRI Table 2-1

Note:
From MGMRI RACT analysis, Table 2-2.

Note:
If add corrected annual operating cost of $9439, CE becomes $25,399

COST EFFECTIVENESS CALCULATION 33	
MGMRI	
BOILERS	
Fuel-Induced Recirculation (FIR2)	
Emissions Unit/Control Technology	
Emissions Unit	MG13
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	FIR2
Baseline Emissions Rate (tpy)	1.66
Emissions Reduction (%)	35.69
Controlled Emissions (tpy)	1.067546
Annualized Capital Costs	
Initial Capital Investment	$94,920
Direct & Indirect Costs	$3,000
Total Capital Investment	$97,920
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$7,114
Annual Operating Costs	
Total Annualized Cost	$7,114
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.592454
Cost Effectiveness ($/ton)	$12,007

Note:
From MGMRI RACT analysis Table 2-1

Note:
From MGMRI RACT analysis, Table 2-1

Note:
Based on 1975 cost for retrofit from 1978 EPA Control Tech doc of $21K (p. 4-55), adjusted with Chem Engr Cost Index (ratio = 824.5 (2022)/182.4 (1975) = 4.52). 4.52x21,000 = $94,920

Note: general estimate

Note:
None estimated

COST EFFECTIVENESS CALCULATION 34	
MGMRI	
BOILERS	
Ceramic Fiber Burners (CFB)	
Emissions Unit/Control Technology	
Emissions Unit	MG13 & MG14
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	CFB
Baseline Emissions Rate (tpy)	1.66
Emissions Reduction (%)	62.5
Controlled Emissions (tpy)	0.6225
Annualized Capital Costs	
Initial Capital Investment	$36,235
Direct & Indirect Costs	$3,000
Total Capital Investment	$39,235
Estimated Equipment Life, years	10
Interest Rate, %	6
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$5,336
Annual Operating Costs	
5% fuel savings	
Total Annualized Cost	$5,336
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.0375
Cost Effectiveness ($/ton)	$5,143

Note:
From MGMRI RACT analysis -actual average annual emissions per boiler

Note:
Based on current 40 ppm v. ceramic 15 ppm: (40-15)/40 = 0.625 = 62.5%

Note:
Based on cost of $0.78/M Btu (per 1000 Btu), 33 MM Btu/hr burner, CEPCI = $824.5/585.7

Note: general estimate

COST EFFECTIVENESS CALCULATION 35	
MGMRI	
BOILERS	
Ceramic Fiber Burners (CFB)	
Emissions Unit/Control Technology	
Emissions Unit	MG13 & MG14
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	CFB
Baseline Emissions Rate (tpy)	1.66
Emissions Reduction (%)	62.5
Controlled Emissions (tpy)	0.6225
Annualized Capital Costs	
Initial Capital Investment	$36,235
Direct & Indirect Costs	$3,000
Total Capital Investment	$39,235
Estimated Equipment Life, years	10
Interest Rate, %	6
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$5,336
Annual Operating Costs	
5% fuel savings assuming 2094 hr/year	$31,959
Total Annualized Cost	-$26,623
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.0375
Cost Effectiveness ($/ton)	-$25,661

Note:
From MGMRI RACT analysis -actual average annual emissions per boiler

Note
Based on current 40 ppm v. ceramic 15 ppm: (40-15)/40 = 0.625 = 62.5%

Note:
Based on cost of $0.78/M Btu (per 1000 Btu), 33 Mm Btu/hr burner, CEPCI = $824.5/585.7

Note: general estimate

Note:
Assumes natural gas at $9.25/1000 cubic feet and operation of the burner at full capacity (33 MM Btu/hr). Operating hours estimated based on actual v. PTE: (1.66/6.95)x8760 = 2094 hr/yr. 2094x(33 mm Btu/hr)x (1 cu ft/1000 Btu)x ($9.25/1000 cu ft) x 0.05) = $31,959/yr

COST EFFECTIVENESS CALCULATION 36	
MGMRI	
BOILERS	
ULNB/FGR	
Emissions Unit/Control Technology	
Emissions Unit	MG13
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	ULNB/FGR
Baseline Emissions Rate (tpy)	1.66
Emissions Reduction (%)	75
Controlled Emissions (tpy)	0.415
Annualized Capital Costs	
Initial Capital Investment	$77,200
Direct & Indirect Costs	$22,211
Total Capital Investment	$99,411
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$7,222
Annual Operating Costs	
General	$9,439
Total Annualized Cost	$16,661
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.245
Cost Effectiveness ($/ton)	$13,382

Note:
From MGMRI Table 2-1

Note:
From MGM RACT, Table 2-1

Note:
From MGMRI RACT analysis, Table 2-2

Note:
From the MGMRI RACT analysis, this annual cost is $22,211. If this is included in the costs but the annual operating cost is left out, CE =

Note:
From MGMRI RACT analysis. Leaving this and direct/indiirect costs out would result in a CE = $4505/ton, but this is unrealistic

COST EFFECTIVENESS CALCULATION 37	
MGMRI	
BOILERS	
Fuel-Induced Recirculation (FIR2)	
Emissions Unit/Control Technology	
Emissions Unit	MG13
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	FIR2
Baseline Emissions Rate (tpy)	1.66
Emissions Reduction (%)	57
Controlled Emissions (tpy)	0.7138
Annualized Capital Costs	
Initial Capital Investment	$94,920
Direct & Indirect Costs	$3,000
Total Capital Investment	$97,920
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$7,114
Annual Operating Costs	
Total Annualized Cost	$7,114
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.9462
Cost Effectiveness ($/ton)	$7,518

Note:
From MGMRI RACT Table 2-1

Note:
From estimated reduction from 40 ppm to 17 ppm = 57%

Note:
Based on 1975 cost for retrofit from 1978 EPA Control Tech doc of $21K (p. 4-55), adjusted with Chem Engr Cost Index (ratio = 824.5 (2022)/182.4 (1975) = 4.52). 4.52x21,000 = $94,920

Note: general estimate

Note:
None estimated

COST EFFECTIVENESS CALCULATION 38	
MGMRI	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
SELECTIVE CATALYTIC REDUCTION (SCR)	
Emissions Unit/Control Technology	
Emissions Unit	EX007
Emission Unit Description	Emergency generator
Pollutant	NOx
Control Technology	SCR
Baseline Emissions Rate (tpy)	3.49
Emissions Reduction (%)	90
Controlled Emissions (tpy)	0.349
Annualized Capital Costs	
Initial Capital Investment	$145,519
Direct & Indirect Costs	$15,340
Total Capital Investment	$160,859
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$11,686
Annual Operating Costs	
Urea	$1,666
Catalyst	$2,702
Maintenance	$6,000
Total Annualized Cost	$22,054
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	3.141
Cost Effectiveness ($/ton)	$7,021

Note:
MGMRI provided no actual emissions for individual units, so used highest PTE of 15.12 times the highest Nelllis AFB actual emissions % of NAFB PTE (Unit 41) PTE = 8.07 tpy, actual max= 1.861, so 23.1% of 15.12 = 3.49

Note:
90% reduction with SCR indicated in literature and WW Williams quote for Caesars

Note:
Based on quotes from WW Williams in Caesars RACT

Note:
From Caesars based on quote from WW Williams

Note:
All costs from Caesars

COST EFFECTIVENESS CALCULATION 39	
MGMRI	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
MANIFOLD AIR TEMPERATURE (MAT) REDUCTION	
Emissions Unit/Control Technology	
Emissions Unit	EX007
Emission Unit Description	Emergency generator
Pollutant	NOx
Control Technology	MAT
Baseline Emissions Rate (tpy)	3.49
Emissions Reduction (%)	70
Controlled Emissions (tpy)	1.047
Annualized Capital Costs	
Initial Capital Investment	$400,000
Direct & Indirect Costs	
Total Capital Investment	$400,000
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$29,060
Annual Operating Costs	
General	$60,000
Maintenance	
Total Annualized Cost	$89,060
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	2.443
Cost Effectiveness ($/ton)	$36,455

Note:
Nelllis AFB actual emissions % of NAFB PTE (Unit 41) PTE = 8.07 tpy, actual max= 1.861, so 23.1% of 15.12 = 3.49

Note:
70% reduction based on formula from 1978 EPA Control Techniques document, Table 4-20, and Komatsu report on an air-cooled aftercooler that lowered inlet air from 356 to 122 F

Note:
1993 ACT, Fig. 6-10

Note:
1993 ACT, Figure 6-10

COST EFFECTIVENESS CALCULATION 40	
MGMRI	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
Direct Water Injection (DWI)	
Emissions Unit/Control Technology	
Emissions Unit	MG17
Emission Unit Description	Emergency generator
Pollutant	NOx
Control Technology	DWI
Baseline Emissions Rate (tpy)	3.49
Emissions Reduction (%)	60
Controlled Emissions (tpy)	1.396
Annualized Capital Costs	
Initial Capital Investment	$84,627
Direct & Indirect Costs	
Total Capital Investment	$84,627
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$6,148
Annual Operating Costs	
2-3% Fuel Penalty	
Other	
Maintenance	$6,000
Total Annualized Cost	$12,148
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	2.094
Cost Effectiveness ($/ton)	$5,801

Note:
Nelllis AFB actual emissions % of NAFB PTE (Unit 41) PTE = 8.07 tpy, actual max= 1.861, so 23.1% of 15.12 = 3.49

Based on Issa article

Note:
Based on Issa article, which gave costs in $/kW for 6000 to 64,000 HP. Includes cost to adapt injection to existing engines. Extrapolated cost to smaller 1880 kW (2520 HP) engine to get $45/kW.

Note:
Double the general maintenance allowance of $3000 diue to potential effect of water injection into the cylinders.

Note:
$11,603/ton if use EPA's control levels of 25-35% (taking 30% midrange)

COST EFFECTIVENESS CALCULATION 41	
MGMRI	
BOILERS	
Overfire Air (OFA)	
Emissions Unit/Control Technology	
Emissions Unit	MG13
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	OFA
Baseline Emissions Rate (tpy)	1.66
Emissions Reduction (%)	50
Controlled Emissions (tpy)	0.83
Annualized Capital Costs	
Initial Capital Investment	$116,318
Direct & Indirect Costs	$3,000
Total Capital Investment	$119,318
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$8,668
Annual Operating Costs	
Total Annualized Cost	$8,668
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.83
Cost Effectiveness ($/ton)	$10,444

Note:
From MGMRI RACT analysis, Table 2-1

Note:
Based on 1975 cost for retrofit from 1978 EPA Control Tech doc of $21K (p. 4-55), adjusted for inflation withChem Engr index to 2022 (2022/1975 = $824.5/182.4 = 4.52

Note: general estimate

Note:
None estimated

COST EFFECTIVENESS CALCULATION 42	
CLARK COUNTY GENERATING STATION (CCGS)	
UNIT 4 (COMBUSTION TURBINE)	
Emissions Unit	4
Pollutant	NOx
Control Technology	SCR
Baseline Emissions (ppm@15% O2)	120
Controlled Emissions (ppm@15% O2)	4
Baseline Emissions Rate (tpy)	37.65
Controlled Emissions (tpy)	1.255
Emissions Reduction (%)	97%
Annualized Capital Costs	
Initial Capital Investment	10,100,000
Direct & Indirect Costs	7,000,000
Total Capital Investment	17,100,000
Estimated Equipment Life, years	15
Interest Rate, %	7.14
Capital Recovery Factor	0.111
Annualized Total Capital Investment	1,894,124
Annual Operating Costs	
Catalyst	156,100
Total Annualized Cost	**2,050,224**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	36.4
Cost Effectiveness ($/ton)	**56,333**

Notes:

1. SCR costs provided by NV Energy based on vendor estimate (see Attachment 7)

2. Achievable emissions for SCR and oxidation catalyst retrofit is based on vendor data provided by NV Energy (see "PMC Budgetary Cost Estimate for SCR/CO Systems for a 60 and 85 MW Simple Cycle CT"

3. Capital interest rate based on interest rate for other capital projects approved by the public utility commission (see Attachment 7)

4. Estimated equipment life for all control options based on EPA CoST Model (version 4.1)

5. Baseline NOx and VOC emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see Attachment 7)

COST EFFECTIVENESS CALCULATION 43	
CLARK COUNTY GENERATING STATION (CCGS)	
UNIT 4 (COMBUSTION TURBINE)	
Emissions Unit	4
Pollutant	NOx
Control Technology	Water Injection
Baseline Emissions (ppm@15% O2)	120
Controlled Emissions (ppm@15% O2)	25
Baseline Emissions Rate (tpy)	37.65
Controlled Emissions (tpy)	7.84
Emissions Reduction (%)	79%
Annualized Capital Costs	
Initial Capital Investment	
Direct & Indirect Costs	
Total Capital Investment	
Estimated Equipment Life, years	
Interest Rate, %	
Capital Recovery Factor	
Annualized Total Capital Investment	
Annual Operating Costs	
Total Annualized Cost	**3,403,512**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	29.8
Cost Effectiveness ($/ton)	**114,188**

Notes:

1. *Water injection costs based on EPA CoST Model (version 4.1):*

Annual Cost (1999$) = annual cost multiplier x design capacity^annual cost exponent + annual base cost

*Annual Cost (1999$) = 3700.2*600^0.95+0 $ 1,612,386*

Design capacity = (60 MW)(1000 kW/MW)(10,000 Btu/kWh)/1000000 = 600 MMBtu/hr

2. *Present value cost adjustment (2022$) = Cost x CEPCI (2022) / CEPCI (YYYY)*

CEPCI (8/2022)	*824.5*
CEPCI (1999)	*390.6*

3. *Achievable emissions for water injection are based on the lowest RBLC determination for similarly equipped unit for 2012-2022 (see RBLC Determinations - Attachment 10). Further investigation may be required to confirm this level of performance.*

4. *Capital interest rate based on interest rate for other capital projects approved by the public utility commission (see Attachment 7)*

5. *Estimated equipment life for all control options based on EPA CoST Model (version 4.1)*

6. *Baseline NOx and VOC emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see Attachment 7)*

COST EFFECTIVENESS CALCULATION 44	
CLARK COUNTY GENERATING STATION (CCGS)	
UNIT 4 (COMBUSTION TURBINE)	
Emissions Unit	4
Pollutant	VOC
Control Technology	Oxidation Catalyst
Baseline Emissions (ppm@15% O2)	85
Controlled Emissions (ppm@15% O2)	17
Baseline Emissions Rate (tpy)	2.05
Controlled Emissions (tpy)	0.41
Emissions Reduction (%)	80%
Annualized Capital Costs	
Initial Capital Investment	2,030,000
Direct & Indirect Costs	1,500,000
Total Capital Investment	3,530,000
Estimated Equipment Life, years	15
Interest Rate, %	7.14
Capital Recovery Factor	0.111
Annualized Total Capital Investment	391,009
Annual Operating Costs	
Catalyst	130,100
Total Annualized Cost	**521,109**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.6
Cost Effectiveness ($/ton)	**317,750**

Notes:

1. Achievable emissions for SCR and oxidation catalyst retrofit is based on vendor data provided by NV Energy (see "PMC Budgetary Cost Estimate for SCR/CO Systems for a 60 and 85 MW Simple Cycle CT"

2. Capital interest rate based on interest rate for other capital projects approved by the public utility commission (see Attachment 7)

3. Estimated equipment life for all control options based on EPA CoST Model (version 4.1)

4. Baseline NOx and VOC emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see Attachment 7)

5. Oxidation catalyst costs provided by NV Energy based on vendor estimate for Unit 5 and scaled using 'six-tenths factor' methodology (see Attachment 7)

6. Baseline emissions concencentration (ppm as propane) provided by NV Energy assuming current emissions 0.024 lb/MMBtu (see Attachment 7)

COST EFFECTIVENESS CALCULATION 45	
CLARK COUNTY GENERATING STATION (CCGS)	
UNIT 5 - 8 (COMBINED CYCLE UNITS)	
Emissions Unit	7
Pollutant	NOx
Control Technology	SCR/LNB
Baseline Emissions (ppm@15% O2)	5
Controlled Emissions (ppm@15% O2)	2
Baseline Emissions Rate (tpy)	14.3
Controlled Emissions (tpy)	5.72
Emissions Reduction (%)	60%
Annualized Capital Costs	
Initial Capital Investment	12,447,496
Direct & Indirect Costs	8,626,977
Total Capital Investment	21,074,473
Estimated Equipment Life, years	15
Interest Rate, %	7.14
Capital Recovery Factor	0.111
Annualized Total Capital Investment	2,334,366
Annual Operating Costs	
Catalyst	192,382
Total Annualized Cost	**2,526,748**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	8.6
Cost Effectiveness ($/ton)	**294,493**

Notes:

1. SCR capital, installation, and catalyst cost is based on NV Energy Unit 4 vendor estimate scaled according to generating capacity using 'six-tenths factor' methodology (see Attachment 7):

$Cost_1 / Cost_2 = (MW_1 / MW_2)^{0.6}$

2. Achievable emissions for SCR/LNB is based the lowest RBLC determination for a similarly equipped unit (see RBLC Determinations - Attachment 10)

3. Capital interest rate based on interest rate for other capital projects approved by the public utility commission (see Attachment 7)

4. Estimated equipment life for all control options based on EPA CoST Model (version 4.1)

5. Baseline NOx and VOC emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see Attachment 7)

6. Unit 7 was selected as representative of all units for the cost effectiveness evaluation because it has the highest baseline emissions.

COST EFFECTIVENESS CALCULATION 46	
CLARK COUNTY GENERATING STATION (CCGS)	
UNIT 5 - 8 (COMBINED CYCLE UNITS)	
Emissions Unit	7
Pollutant	VOC
Control Technology	Oxidation Catalyst
Baseline Emissions (ppm@15% O2)	16
Controlled Emissions (ppm@15% O2)	2
Baseline Emissions Rate (tpy)	4.57
Controlled Emissions (tpy)	0.57
Emissions Reduction (%)	88%
Annualized Capital Costs	
Initial Capital Investment	2,500,000
Direct & Indirect Costs	1,500,000
Total Capital Investment	4,000,000
Estimated Equipment Life, years	15
Interest Rate, %	7.14
Capital Recovery Factor	0.111
Annualized Total Capital Investment	443,070
Annual Operating Costs	
Catalyst	130,100
Total Annualized Cost	**573,170**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	4.0
Cost Effectiveness ($/ton)	**143,337**

Notes:

according to generating capacity using 'six-tenths factor' methodology (see Attachment 9):

$Cost_1/Cost_2 = (MW_1/MW_2)^{0.6}$

2. Oxidation catalyst costs provided by NV Energy based on vendor estimate (see Attachment 7)

3. Achievable oxidation catalyst retrofit is based on vendor data provided by NV Energy (see "PMC Budgetary Cost Estimate for SCR/CO Systems for a 60 and 85 MW Simple Cycle CT"

4. Capital interest rate based on interest rate for other capital projects approved by the public utility commission (see Attachment 7)

5. Estimated equipment life for all control options based on EPA CoST Model (version 4.1)

6. Baseline NOx and VOC emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see Attachment 7)

7. Baseline emissions concencentration (ppm as propane) provided by NV Energy assuming current emissions 0.0046 lb/MMBtu (see Attachment 7)

8. Unit 7 was selected as representative of all units for the cost effectiveness evaluation because it has the highest baseline emissions.

COST EFFECTIVENESS CALCULATION 47	
CLARK COUNTY GENERATING STATION (CCGS)	
UNIT 11 - 22 (COMBUSTION TURBINES)	
Emissions Unit	14
Pollutant	NOx
Control Technology	SCR/LNB
Baseline Emissions (ppm@15% O2)	5
Controlled Emissions (ppm@15% O2)	2
Baseline Emissions Rate (tpy)	4.37
Controlled Emissions (tpy)	1.748
Emissions Reduction (%)	60%
Annualized Capital Costs	
Initial Capital Investment	
Direct & Indirect Costs	
Total Capital Investment	19,000,000
Estimated Equipment Life, years	15
Interest Rate, %	7.14
Capital Recovery Factor	0.111
Annualized Total Capital Investment	2,104,582
Annual Operating Costs	
Total Annualized Cost	**2,104,582**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	2.6
Cost Effectiveness ($/ton)	**802,663**

Notes:

1. LNB total installed cost is based on CCGS Unit 4 vendor estimate (see Attachment 7a - RACT Analysis Request for Supporting Documentation (1/30/2023))

2. SCR upgrade costs are based on Saguaro Power Company vendor estimate for 35 MW CCU and scaled using 'six-tenths factor' methodology:

$Cost_2 = Cost_1 (MW_2/MW_1)^{0.6}$

3. Achievable emissions for SCR/LNB is based the lowest RBLC determination for a similarly equipped unit (see RBLC Determinations - Attachment 10)

4. Capital interest rate based on interest rate for other capital projects approved by the public utility commission (see Attachment 7)

5. Estimated equipment life for all control options based on EPA CoST Model (version 4.1)

6. Baseline NOx and VOC emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see NV Energy RACT Analysis - Attachment 7)

7. Unit 14 was selected as representative of all units for the cost effectiveness evaluation because it has the highest baseline emissions.

COST EFFECTIVENESS CALCULATION 48 SUN PEAK GENERATING STATION (SPGS) UNITS 3-5 (COMBUSTION TURBINES)	
Emissions Unit	3
Pollutant	NOx
Control Technology	SCR
Baseline Emissions (ppm@15% O2)	37
Controlled Emissions (ppm@15% O2)	2
Baseline Emissions Rate (tpy)	32.19
Controlled Emissions (tpy)	1.74
Emissions Reduction (%)	95%
Annualized Capital Costs	
Initial Capital Investment	12,500,000
Direct & Indirect Costs	8,500,000
Total Capital Investment	21,000,000
Estimated Equipment Life, years	15
Interest Rate, %	7.14
Capital Recovery Factor	0.111
Annualized Total Capital Investment	2,326,117
Annual Operating Costs	
Catalyst	192,382
Total Annualized Cost	**2,518,499**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	30.5
Cost Effectiveness ($/ton)	**82,709**

Notes:

1. SCR total installed cost is based on SPGS vendor estimate (see Attachment 7a - RACT Analysis Request for Supporting Documentation (1/30/2023))

2. SCR catalyst cost is based on vendor estimate for CCGS Unit 4 (see Attachment 7a - RACT Analysis Request for Supporting Documentation (1/30/2023))

3. Achievable emissions for SCR is based on vendor data provided by NV Energy (see Attachment 7a - RACT Analysis Request for Supporting Documentation (1/30/2023))

4. Capital interest rate based on interest rate for other capital projects approved by the public utility commission (see Attachment 7)

5. Estimated equipment life for all control options based on EPA CoST Model (version 4.1)

6. Baseline NOx (tpy) based on maximum two-year annual average for the period 2017-2021 (see Attachment 7 - NV Energy RACT Analysis)

7. Unit 3 was selected as representative of all units for the cost effectiveness evaluation because it has the highest baseline emissions.

COST EFFECTIVENESS CALCULATION 49 SUN PEAK GENERATING STATION (SPGS) UNITS 3-5 (COMBUSTION TURBINES)	
Emissions Unit	3
Pollutant	NOx
Control Technology	LNB
Baseline Emissions (ppm@15% O2)	37
Controlled Emissions (ppm@15% O2)	9
Baseline Emissions Rate (tpy)	32.19
Controlled Emissions (tpy)	7.83
Emissions Reduction (%)	76%
Annualized Capital Costs	
Initial Capital Investment	9,000,000
Direct & Indirect Costs	1,500,000
Total Capital Investment	10,500,000
Estimated Equipment Life, years	15
Interest Rate, %	7.14
Capital Recovery Factor	0.111
Annualized Total Capital Investment	1,163,059
Annual Operating Costs	
Total Annualized Cost	**1,163,059**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	24.4
Cost Effectiveness ($/ton)	**47,745**

Notes:

1. *Achievable emissions for LNB are based on the vendor estimate (see Attachment 7 - NV Energy RACT Analysis)*
2. *Capital interest rate based on interest rate for other capital projects approved by the public utility commission (see Attachment 7)*
3. *Estimated equipment life for all control options based on EPA CoST Model (version 4.1)*
4. *Baseline NOx (tpy) based on maximum two-year annual average for the period 2017-2021 (see Attachment 7 - NV Energy RACT Analysis)*
5. *Unit 3 was selected as representative of all units for the cost effectiveness evaluation because it has the highest baseline emissions.*

COST EFFECTIVENESS CALCULATION 50	
SAGUARO POWER COMPANY	
UNIT 1 AND 2 (COMBINED CYCLE UNITS)	
Emissions Unit	2
Pollutant	NOx
Control Technology	SCR/LNB
Baseline Emissions (ppm@15% O2)	10
Controlled Emissions (ppm@15% O2)	2
Baseline Emissions Rate (tpy)	54.40
Controlled Emissions (tpy)	10.88
Emissions Reduction (%)	80%
Annualized Capital Costs	
Initial Capital Investment	3,793,000
Direct & Indirect Costs	
Total Capital Investment	3,793,000
Estimated Equipment Life, years	15
Interest Rate, %	7.14
Capital Recovery Factor	0.111
Annualized Total Capital Investment	420,141
Annual Operating Costs	
Total Annualized Cost	**420,141**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	43.5
Cost Effectiveness ($/ton)	**9,654**

Notes:

1. LNB total installed cost is based on CCGS Unit 4 vendor estimate (see Attachment 8 - SPC RACT Analysis)

2. Achievable emissions for SCR/LNB is based the lowest RBLC determination for a similarly equipped unit (see RBLC Determinations - Attachment 10)

3. Capital interest rate based on interest rate as per DAQ RACT guidelines.

4. Estimated equipment life is based on EPA CoST Model (version 4.1)

5. Baseline NOx emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see SPC RACT Analysis - Attachment 8)

6. Unit 2 was selected as representative of both units for the cost effectiveness evaluation because it has the highest baseline emissions.

COST EFFECTIVENESS CALCULATION 51	
SAGUARO POWER COMPANY	
UNIT 1 AND 2 (COMBINED CYCLE UNITS)	
Emissions Unit	2
Pollutant	NOx
Control Technology	Replace Catalyst on Existing SCR
Baseline Emissions (ppm@15% O2)	10
Controlled Emissions (ppm@15% O2)	3
Baseline Emissions Rate (tpy)	54.40
Controlled Emissions (tpy)	16.32
Emissions Reduction (%)	70%
Annualized Capital Costs	
Initial Capital Investment	607,500
Direct & Indirect Costs	
Total Capital Investment	607,500
Estimated Equipment Life, years	5
Interest Rate, %	7.14
Capital Recovery Factor	0.245
Annualized Total Capital Investment	148,719
Annual Operating Costs	
Ammonia	207,500
Total Annualized Cost	**356,219**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	38.1
Cost Effectiveness ($/ton)	**9,355**

Notes:

1. SCR catalyst replacement costs are based on Saguaro Power Company vendor estimate. DAQ assumes the additional ammonia is based on a catalyst replacement project that accommodates higher ammonia injection rates.

2. Achievable emissions with the catalyst replacement is based on the highest RBLC determination (range is 2-3 ppm @ 15% O2) for a similarly equipped unit (SCR/steam injection) (see RBLC Determinations - Attachment 10)

3. The highest value was selected due to the uncertainty in the scope of the SCR catalyst replacement project.

4. Capital interest rate based on interest rate as per DAQ RACT guidelines.

5. Estimated equipment life assumes a five-year catalyst replacement cycle

6. Baseline NOx emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see SPC RACT Analysis - Attachment 8)

7. Unit 2 was selected as representative of both units for the cost effectiveness evaluation because it has the highest baseline emissions.

COST EFFECTIVENESS CALCULATION 52	
SAGUARO POWER COMPANY	
UNIT 5 (Indeck/Volcano Auxiliary Boiler)	
Emissions Unit	5
Pollutant	NOx
Control Technology	N/A
Baseline Emissions (ppm@3% O2)	12
Controlled Emissions (ppm@3% O2)	8.2
Baseline Emissions Rate (tpy)	0.39
Controlled Emissions (tpy)	0.27
Emissions Reduction (%)	32%
Annualized Capital Costs	
Initial Capital Investment	6,500
Direct & Indirect Costs	
Total Capital Investment	6,500
Estimated Equipment Life, years	15
Interest Rate, %	6.0
Capital Recovery Factor	0.103
Annualized Total Capital Investment	669
Annual Operating Costs	
Total Annualized Cost	**669**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.1
Cost Effectiveness ($/ton)	**5,419**

Notes:

1. Capital interest rate based on interest rate as per DAQ RACT guidelines.

2. Estimated equipment life for combustion-related upgrades are 15 years based on EPA CoST Model (version 4.1)

3.Baseline NOx emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see Attachment 8 - SPC RACT Analysis)

DAQ did not have sufficient information at the time of this evaluation to determine the technical feasibility of the combustion-related NOx controls. All/some of these options would be eliminated if the existing oxidation catalyst system is unable to offset additional CO formation by modifying the existing burner. DAQ also notes that any post-combustion controls (SCR) are not feasible due to relatively low boiler exit temperature. While technical feasibility of the combustion-NOx controls cannot be established, DAQ evaluated potential costs to determine whether there may be any cost-effective combustion controls even if they were deemed to be technically feasible. The data suggests that TCI would need to be less than $6,500 to achieve a RACT level reduction of 0.01 lb/MMBtu (~8.2 PPM @ 3% O2), which is the lowest RBLC determination for any combustion-related control option. DAQ is not aware of any potential upgrade that can be purchased for this cost.

COST EFFECTIVENESS CALCULATION 53	
SAGUARO POWER COMPANY	
UNIT 6 (NEBRASKA BOILER)	
Emissions Unit	6
Pollutant	NOx
Control Technology	LNB Replacement with FGR
Baseline Emissions (ppm@3% O2)	30
Controlled Emissions (ppm@3% O2)	9
Baseline Emissions Rate (tpy)	1.39
Controlled Emissions (tpy)	0.42
Emissions Reduction (%)	70%
Annualized Capital Costs	
Initial Capital Investment	657,629
Direct & Indirect Costs	
Total Capital Investment	657,629
Estimated Equipment Life, years	15
Interest Rate, %	6.0
Capital Recovery Factor	0.103
Annualized Total Capital Investment	67,711
Annual Operating Costs	
Total Annualized Cost	**67,711**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.0
Cost Effectiveness ($/ton)	**69,590**

Notes:

1. LNB/FGR cost is based on SPC vendor estimate (see Attachment 8 - SPC RACT Analysis). The estimate does not appear to include direct installation cost.

2. Achievable emissions are based on SPC vendor guarantee (see Attachment 8 - SPC RACT Analysis).

3. Capital interest rate based on DAQ RACT Guidelines document

4. Estimated equipment life for all control options based on EPA CoST Model (version 4.1)

5. Baseline NOx emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see Attachment 8 - SPC RACT Analysis)

COST EFFECTIVENESS CALCULATION 53a	
SAGUARO POWER COMPANY	
UNIT 6 (NEBRASKA BOILER)	
Emissions Unit	6
Pollutant	NOx
Control Technology	LNB Replacement with Metal Mesh LNB+FGR
Baseline Emissions (ppm@3% O2)	30
Controlled Emissions (ppm@3% O2)	5
Baseline Emissions Rate (tpy)	1.39
Controlled Emissions (tpy)	0.23
Emissions Reduction (%)	83%
Annualized Capital Costs	
Initial Capital Investment	385,870
Direct & Indirect Costs	
Total Capital Investment	385,870
Estimated Equipment Life, years	15
Interest Rate, %	6.0
Capital Recovery Factor	0.103
Annualized Total Capital Investment	39,730
Annual Operating Costs	
Total Annualized Cost	**39,730**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.2
Cost Effectiveness ($/ton)	**34,299**

Notes:

1. The capital cost is based on a budgetary estimate provided to RTP (8/14/2023 email from Jason Howard to Note:) from Alzeta for a 35 MMBtu/hr firetube boiler ($225K) and scaled using 'six-tenths factor' methodology:

$$Cost_2 = Cost_1 (MW_2 / MW_1)^{0.6}$$

$Cost_1$ (2023$)	$	225,000
HI_1 (MMBtu/hr)		35
HI_2 (MMBtu/hr)		86
Cost2 (2023$)	$	385,870

2. Estimate does not include direct installation cost

3. Achievable emissions of 5 ppm @ 3% O_2 based on a vendor literature. Literature suggests burners are capable of < 9 ppm but does not specify. DAQ assumes 5 ppm for conservatism using FGR option.

4. Capital interest rate based on interest rate as per DAQ RACT guidelines.

5. Estimated equipment life for combustion-related upgrades are 15 years based on EPA CoST Model (version 4.1) for LNB. Did not receive any information from vendor on equipment life.

6. Baseline NOx emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see Attachment 8 - SPC RACT Analysis)

This LNB option (surface stabilized combustion burner), marketed by Alzeta (CSB product line), was identified by RTP during the preparation of the final report. Although budgetary costs were not provided in time for the final report by the vendor for this specific boiler, cost information was obtained for a similar burner design. Because cost effectiveness is >> DAQ cost threshold ($5,500/ton), this option was also eliminated from consideration. The cost and performance estimates used in the final report for the 'LNB+FGR' option are based on the assumptions below (8/15/2023).

COST EFFECTIVENESS CALCULATION 54 SAGUARO POWER COMPANY UNIT 6 (NEBRASKA BOILER)	
Emissions Unit	6
Pollutant	NOx
Control Technology	LNB Replacement with FGR
Baseline Emissions (ppm@3% O2)	30
Controlled Emissions (ppm@3% O2)	15
Baseline Emissions Rate (tpy)	1.39
Controlled Emissions (tpy)	0.70
Emissions Reduction (%)	50%
Annualized Capital Costs	
Initial Capital Investment	94,430
Direct & Indirect Costs	
Total Capital Investment	94,430
Estimated Equipment Life, years	10
Interest Rate, %	6.0
Capital Recovery Factor	0.136
Annualized Total Capital Investment	12,830
Annual Operating Costs	
Total Annualized Cost	**12,830**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.7
Cost Effectiveness ($/ton)	**18,460**

Notes:

1. The capital cost of the ceramic fiber burner ($0.78/1000 Btu (2011$)) based on a whitepaper (Characterizing Costs, Savings, and Benefits of a Selection of Energy Efficient Emerging Technologies in the

Burner Rating (MMBtu/hr)		*86*	
Burner Equipment Cost	*$*	*67,080*	*2011$*
	$	*94,430*	*2022$*

2. Present value cost adjustment (2022$) = Cost x CEPCI (2022) / CEPCI (YYYY)

CEPCI (8/2022)	*824.5*
CEPCI (2011)	*585.7*

3. Estimate does not include direct installation cost

4. Achievable emissions of 15 ppm @ 3% O_2 based on a vendor whitepaper (Radiant Fiber Burners for Gas-Fired Appliances and Equipment, John P. Kesselring, Robert M. Kendall, and Richard J. Schreiber, Alzeta

5. Capital interest rate based on interest rate as per DAQ RACT guidelines.

6. Estimated equipment life for combustion-related upgrades are 15 years based on EPA CoST Model (version 4.1)

7. Baseline NOx emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see Attachment 10 - SPC RACT Analysis)

COST EFFECTIVENESS CALCULATION 55	
SAGUARO POWER COMPANY	
UNIT 6 (NEBRASKA BOILER)	
Emissions Unit	6
Pollutant	NOx
Control Technology	FIR
Baseline Emissions (ppm@3% O2)	30
Controlled Emissions (ppm@3% O2)	9
Baseline Emissions Rate (tpy)	1.39
Controlled Emissions (tpy)	0.42
Emissions Reduction (%)	70%
Annualized Capital Costs	
Initial Capital Investment	507,629
Direct & Indirect Costs	
Total Capital Investment	507,629
Estimated Equipment Life, years	15
Interest Rate, %	6.0
Capital Recovery Factor	0.103
Annualized Total Capital Investment	52,267
Annual Operating Costs	
Total Annualized Cost	**52,267**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.0
Cost Effectiveness ($/ton)	**53,717**

Notes:

1. Achievable emissions are assumed to be similar to LNB upgrade+FGR (9 ppm @ 3% O2). LNB+FGR performance is based on vendor guarantee (see Attachment 8 - SPC RACT Analysis)

2. FIR costs are assumed to be the same as LNB upgrade without FGR. This cost is based on a vendor estimate for LNB+FGR (see Attachment 8 - SPC RACT Analysis)

3. DAQ did not include the 'cost adder for 9 ppm' ($150K) because this represents the additional cost of FGR in the LNB+FGR cost estimate.

4. Capital interest rate based on interest rate as per DAQ RACT guidelines.

5. Estimated equipment life for combustion-related upgrades are 15 years based on EPA CoST Model (version 4.1)

6. Baseline NOx emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see Attachment 8 - SPC RACT Analysis)

COST EFFECTIVENESS CALCULATION 56	
SAGUARO POWER COMPANY	
UNIT 6 (NEBRASKA BOILER)	
Emissions Unit	6
Pollutant	NOx
Control Technology	FIR2
Baseline Emissions (ppm@3% O2)	30
Controlled Emissions (ppm@3% O2)	13
Baseline Emissions Rate (tpy)	1.39
Controlled Emissions (tpy)	0.58
Emissions Reduction (%)	58%
Annualized Capital Costs	
Initial Capital Investment	150,000
Direct & Indirect Costs	
Total Capital Investment	150,000
Estimated Equipment Life, years	15
Interest Rate, %	6
Capital Recovery Factor	0.103
Annualized Total Capital Investment	15,444
Annual Operating Costs	
Total Annualized Cost	**15,444**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.8
Cost Effectiveness ($/ton)	**19,157**

Notes:

1. *Achievable emissions assume an incremental reduction of 58% based on the average removal efficiency demonstrated in a utility boiler study (Demonstration of Fuel Injection Recirculation (FIR) for NOx Emissions Control, Reese, James L., et al., 1994).*

2. *FIR2 costs are assumed to be the same as the installation of FGR without burner replacement. This cost is based on a vendor estimate for LNB+FGR (see Attachment 8 - SPC RACT Analysis)*

3. *DAQ assumes that the 'cost adder for 9 ppm' ($150K) represents the additional cost for adding FGR in the LNB+FGR cost estimate. This may understate actual cost associated with FGR retrofit w/o burner replacement.*

4. *Capital interest rate based on interest rate as per DAQ RACT guidelines.*

5. *Estimated equipment life for combustion-related upgrades are 15 years based on EPA CoST Model (version 4.1)*

6. *Baseline NOx emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see Attachment 8 - SPC RACT Analysis)*

COST EFFECTIVENESS CALCULATION 57	
SAGUARO POWER COMPANY	
UNIT 6 (NEBRASKA BOILER)	
Emissions Unit	6
Pollutant	NOx
Control Technology	FGR
Baseline Emissions (ppm@3% O2)	30
Controlled Emissions (ppm@3% O2)	15
Baseline Emissions Rate (tpy)	1.39
Controlled Emissions (tpy)	0.70
Emissions Reduction (%)	50%
Annualized Capital Costs	
Initial Capital Investment	150,000
Direct & Indirect Costs	
Total Capital Investment	150,000
Estimated Equipment Life, years	15
Interest Rate, %	6
Capital Recovery Factor	0.103
Annualized Total Capital Investment	15,444
Annual Operating Costs	
Total Annualized Cost	**15,444**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.7
Cost Effectiveness ($/ton)	**22,222**

Notes:

1. Achievable emissions assumes an incremental reduction of 50% based on the upper range of expected performance from other installations (40-50% using 20-30% FGR).

2. FIR costs are assumed to be the same as the installation of FGR without burner replacement. This cost is based on a vendor estimate for LNB+FGR (see Attachment 8 - SPC RACT Analysis)

3. DAQ assumes that the 'cost adder for 9 ppm' ($150K) represents the additional cost for adding FGR in the LNB+FGR cost estimate. This may understate actual cost associated with FGR retrofit w/o burner replacement.

4. Capital interest rate based on interest rate as per DAQ RACT guidelines.

5. Estimated equipment life for combustion-related upgrades are 15 years based on EPA CoST Model (version 4.1)

6. Baseline NOx emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see Attachment 8 - SPC RACT Analysis)

Appendix 10

DAQ RBLC Determinations

RBLCID	FACILITY NAME	STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	UNITS	CONTROL METHOD	EMISSION LIMIT 1	UNITS	AVERAGING TIME	EMISSION LIMIT 2	UNITS	AVERAGING TIME	STANDARD EMISSION LIMIT	UNITS	AVERAGING TIME
AL-0307	ALLOYS PLANT	AL	10/9/2015	PACKAGE BOILER	17.5	MMBTU/H	LOW NOX BURNER FLUE GAS RECIRCULATION GCP	30	PPMVD	3% O2	0.64	LB/H		0		
AL-0307	ALLOYS PLANT	AL	10/9/2015	2 CALP LINE BOILERS	24.59	MMBTU/H	LOW NOX BURNER FLUE GAS RECIRCULATION (FGR) GOOD COMBUSTION PRACTICES (GCP)	30	PPMVD	3% O2	0.9	LB/H		0		
FL-0335	SUWANNEE MILL	FL	9/5/2012	Four(4) Natural Gas Boilers - 46 MMBtu/hour	46	MMBTU/H	Low NOx Burner and Flue Gas Recirculation	0.036	LB/MMBTU		0			0		
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	TWO (2) NATURAL GAS AUXILIARY BOILERS	80	MMBTU/H	LOW NOX BURNER WITH FLUE GAS RECIRCULATION	0.032	LB/MMBTU	3 HOURS	2.56	LB/H	3 HOURS	0		
MD-0041	CPV ST. CHARLES	MD	4/23/2014	AUXILLARY BOILER	93	MMBTU/H	EXCLUSIVE USE OF NATURAL GAS, ULTRA LOW-NOX BURNERS, AND FLUE GAS RECIRCULATION (FGR)	0.011	LB/MMBTU	3-HOUR AVERAGE	0			0		
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FGAUXBOILERS: Two auxiliary boilers < 100 MMBTU/H heat input each	100	MMBTU/H heat input each	Low NOx burners and flue gas recirculation.	0.05	LB/MMBTU	TEST PROTOCOL	0			0		
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	Auxiliary Boiler B (EUAUXBOILERB)	95	MMBTU/H	Dry low NOx burners, flue gas recirculation and good combustion practices.	0.05	LB/MMBTU	TEST PROTOCOL	0			0		
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	EUAUXBOILER (Auxiliary boiler)	83.5	MMBTU/H	Low NOx burners/Internal flue gas recirculation and good combustion practices.	0.05	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	0			0		
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUAUXBOILER (North Plant): Auxiliary Boilder	61.5	MMBTU/H	Low NOx burners/flue gas recirculation and good combustion practices.	0.04	LB/MMBTU	30-DAY ROLLING AVG TIME PERIOD	0			0		
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUAUXBOILER (South Plant): Auxiliary Boiler	61.5	MMBTU/h	Low NOx burners/flue gas recirculation and good combustion practices.	0.04	LB/MMBTU	30 DAY ROLLING AVG TIME PERIOD	0			0		
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUAUXBOILER: Auxiliary Boiler	99.9	MMBTU/H	Low NOx burners/Flue gas recirculation.	0.036	LB/MMBTU	HOURLY	3.6	LB/H	HOURLY	0		
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Boiler less than 100 MMBtu/hr	51.9	mmcubic ft/year	Low NOx burners and flue gas recirculation	0.01	LB/MMBTU	AVERAGE OF THREE TESTS	0.66	LB/H	AVERAGE OF THREE TESTS	0		
NY-0103	CRICKET VALLEY ENERGY CENTER	NY	2/3/2016	Auxiliary boiler	60	MMBTU/H	flue gas recirculation with low NOx burners	0.0085	LB/MMBTU	1 H	0			0		
NY-0104	CPV VALLEY ENERGY CENTER	NY	8/1/2013	Auxiliary boiler	0		Flue gas recirculation with low NOx burners.	0.045	LB/MMBTU	1 H	0			0		
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	Auxillary Boiler	99	MMBtu/H	low NOx burners and flue gas recirculation	1.98	LB/H		1.98	T/YR	PER ROLLING 12-MONTHS	0.02	LB/MMBTU	
OH-0360	CARROLL COUNTY ENERGY	OH	11/5/2013	Auxiliary Boiler (B001)	99	MMBtu/H	low NOx burners and flue gas recirculation	1.98	LB/H		4.46	T/YR		0.02	LB/MMBTU	
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	8/25/2015	Auxiliary Boiler (B001)	34	MMBTU/H	Flue gas recirculation (FGR) and low NOx burner	0.68	LB/H		0.68	T/YR	PER ROLLING 12 MONTH PERIOD	0.02	LB/MMBTU	
OH-0370	TRUMBULL ENERGY CENTER	OH	9/7/2017	Auxiliary Boiler (B001)	37.8	MMBTU/H	Flue gas recirculation (FGR), low NOx burner	0.76	LB/H		0.76	T/YR	PER ROLLING 12 MONTH PERIOD	0.02	LB/MMBTU	
OH-0372	OREGON ENERGY CENTER	OH	9/27/2017	Auxiliary Boiler (B001)	37.8	MMBTU/H	low NOX burners and flue gas recirculation	0.76	LB/H		0.76	T/YR	PER ROLLING 12 MONTH PERIOD	0.02	LB/MMBTU	
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	11/7/2017	Auxiliary Boiler (B001)	26.8	MMBTU/H	Flue gas recirculation and low NOX burner	0.29	LB/H		0.74	T/YR	PER ROLLING 12 MONTH PERIOD	0.011	LB/MMBTU	
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	Auxiliary boiler	39.8	MMBTU/H	Utilize Low-NOx burners and FGR.	0.035	LB/MMBTU	3-HR BLOCK AVERAGE	0			0		
PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	PA	6/15/2015	Auxilary Boiler	62.04	MCF/hr	Good combustion practices, Ultra-Low NOx burners, FGR	0.0086	LB/MMBTU		2.3	TPY	ANY CONSECUTIVE 12-MONTH PERIOD	0		
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Auxilary boiler	92.4	MMBtu/hr	Ultra low NOx burners, FGR, good combustion practices	0.011	LB/MMBTU	AVG OF 3 1-HR TEST RUNS	2.03	TPY	12-MONTH ROLLING BASIS	0		

*PA-0319	RENAISSANCE ENERGY CENTER	PA	8/27/2018	NATURAL GAS FIRED AUXILIARY BOILER	88	MMBtu/hr	Lo-NOx burners, Flue Gas Recirculation, good combustion practices, proper operation and maintainance.	0.02	LB/MMBTU	HR	0			0		
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	TX	11/6/2015	Commercial/Institutional-Size Boilers/Furnaces	95.7	MMBTU/H	Low NOx burners and flue gas recirculation	0.011	LB/MMBTU		0			0		
WI-0283	AFE, INC. â€“LCM PLANT	WI	4/24/2018	B01-B12, Boilers	28	mmBTU/hr	Ultra-low NOx Burners, Flue Gas Recirculation and Good Combustion Practices	0.0105	LB/MMBTU		0			0		
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	WI	4/24/2018	B13-B24 & B25-B36 Natural Gas-Fired Boilers	28	mmBTU	Ultra-Low NOx Burners, Flue Gas Recirculation, and Good Combustion Practices.	0.0105	LB/MMBTU	1-HOUR AVERAGE	0			0		
*WV-0029	HARRISON COUNTY POWER PLANT	WV	3/27/2018	Auxiliary Boiler	77.8	mmBtu/hr	LNB, FGR, Good Combustion Practices	0.86	LB/HR		1.96	TONS/YEAR		0.0011	LB/MMBTU	
WY-0075	CHEYENNE PRAIRIE GENERATING STATION	WY	7/16/2014	Auxiliary Boiler	25.06	MMBtu/h	Ultra low NOx burners and flue gas recirculation	0.0175	LB/MMBTU	3 HOUR AVERAGE	0.4	LB/H	3 HOUR AVERAGE	0		

RBLCID	FACILITY NAME	STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	UNITS	CONTROL METHOD	EMISSION LIMIT 1	UNITS	AVERAGING TIME	EMISSION LIMIT 2	UNITS	AVERAGING TIME	STANDARD EMISSION LIMIT	UNITS	AVERAGING TIME
IN-0261	VERMILLION GENERATING STATION	IN	2/28/2017	SIMPLE CYCLE, NATURAL GAS FIRED COMBUSTION TURBINES	80	MW	GOOD COMBUSTION PRACTICES	250	LB/H	EACH TURBINE	25	TON/12 CONSEC. MONTH	COMPLIANCE DETERMINED END OF EACH MONTH	0		
LA-0343	SABINE PASS LNG TERMINAL	LA	9/6/2019	gas turbines during startups, shutdowns, and maintenance	0		good combustion practices	96	PPMV	@ 15% O2	0			0		

RBLCID	FACILITY NAME	STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	UNITS	CONTROL METHOD	EMISSION LIMIT 1	UNITS	AVERAGING TIME	EMISSION LIMIT 2	UNITS	AVERAGING TIME	STANDARD EMISSION LIMIT	UNITS	AVERAGING TIME
IN-0264	MONTPELIER GENERATING STATION	IN	1/6/2017	PRATT & TWIN-PAC SIMPLE CYCLE TURBINES	270.9	MMBTU/H	WATER INJECTION	25	PPMV	AT 15% O2 FOR NATURAL GAS	42	PPMV	AT 15% O2 FOR FUEL OIL	0		

RBLCID	FACILITY NAME	STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	UNITS	CONTROL METHOD	EMISSION LIMIT 1	UNITS	AVERAGING TIME	EMISSION LIMIT 2	UNITS	AVERAGING TIME	STANDARD EMISSION LIMIT	UNITS	AVERAGING TIME
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Aeroderivative Simple Cycle Combustion Turbine	263	MM BTU/h	Selective Catalytic Reduction (SCR), exclusive combustion of fuel gas, and good combustion practices.	25	PPMV	30 DAY ROLLING AVERAGE	0			0		
ND-0030	LONESOME CREEK GENERATING STATION	ND	9/16/2013	Natural Gas Fired Simple Cycle Turbines	412	MMBTU/H	SCR	5	PPMVD	4 HOUR ROLLING AVERAGE EXCEPT STARTUP	18.5	LB	TOTAL FOR 30 MINUTES DURING STARTUP	0		
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Simple Cycle Turbine (EP03)	40	MW	SCR	5	PPMV AT 15% O2	1-HOUR	7.7	LB/H	30-DAY ROLLING AVERAGE	36	T/YR	
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Simple Cycle Trubine (EP04)	40	MW	SCR	5	PPMV AT 15% O2	1-HOUR AVERAGE	7.7	LB/H	30-DAY ROLLING AVERAGE	36	T/YR	
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Simple Cycle Turbine (EP05)	40	MW	SCR	5	PPMV AT 15% O2	1-HOUR	7.7	LB/H	30-DAY ROLLING AVERAGE	36	T/YR	

RBLCID	FACILITY NAME	STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	UNITS	CONTROL METHOD	EMISSION LIMIT 1	UNITS	AVERAGING TIME	EMISSION LIMIT 2	UNITS	AVERAGING TIME	STANDARD EMISSION LIMIT	UNITS	AVERAGING TIME
AK-0088	LIQUEFACTION PLANT	AK	7/7/2022	Six Simle Cycle Gas-Fired Turbines	1113	MMBtu/hr	SCR, DLN combustors, and good combustion practices	2	PPMV @ 15% O2	3-HOURS	0			0		
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	LA	9/3/2020	Turbines (EQT0020 - EQT0031)			LNB + SCR	3.1	PPMVD @15%O2	3-HOUR AVERAGE	0			0		
MD-0044	COVE POINT LNG TERMINAL	MD	6/9/2014	2 COMBUSTION TURBINES	130	MW	USE OF DRY LOW-NOX COMBUSTOR TURBINE DESIGN (DLN1), USE OF FACILITY PROCESS FUEL GAS AND PIPELINE NATURAL GAS DURING NORMAL OPERATION AND SCR SYSTEM	2.5	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD	1304.5	LB/EVENT	FOR ALL STARTUPS	0		

RBLC Query Results - NOx (SCR+Water Injection) (15.110 - Gas Fired Simple Cycle Turbines)

RBLCID	FACILITY NAME	STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	UNITS	CONTROL METHOD	EMISSION LIMIT 1	UNITS	AVERAGING TIME	EMISSION LIMIT 2	UNITS	AVERAGING TIME	STANDARD EMISSION LIMIT	UNITS	AVERAGING TIME
CA-1223	PIO PICO ENERGY CENTER	CA	11/19/2012	COMBUSTION TURBINES (NORMAL OPERATION)	300	MW	WATER INJECTION, SCR	2.5	PPMVD	@15% O2, 1-HR AVG	8.18	LB/H	1-HR AVG	0		
CA-1223	PIO PICO ENERGY CENTER	CA	11/19/2012	(STARTUP & SHUTDOWN PERIODS)	300	MW	water injection and SCR system	22.5	LB/H	STARTUP EVENTS	6	LB/H	SHUTDOWN EVENTS	0		
ND-0029	PIONEER GENERATING STATION	ND	5/14/2013	Natural gas-fired turbines	451	MMBTU/H	Water injection plus SCR	5	PPPMVD	AVERAGE EXCEPT FOR	19	LB/H	DURING STARTUP	0		
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	turbines, simple cycle with water injection	1690	MMBTU/H	combusting natural gas or ULSD;	2.5	PPMDV AT 15% O2	AVERAGE ON NG	3.8	PPMDV AT 15% O2	AVERAGE ON ULSD	0		

RBLCID	FACILITY NAME	STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	UNITS	CONTROL METHOD	EMISSION LIMIT 1	UNITS	AVERAGING TIME	EMISSION LIMIT 2	UNITS	AVERAGING TIME	STANDARD EMISSION LIMIT	UNITS	AVERAGING TIME
AK-0085	GAS TREATMENT PLANT	AK	8/13/2020	Six (6) Simple Cycle Gas-Turbines (Power Generation)	386	MMBtu/hr	Good Combustion Practices and burning clean fuels (NG)	0.0022	LB/MMBTU	3-HOUR AVERAGE	0			0		
FL-0346	LAUDERDALE PLANT	FL	4/22/2014	Five 200-MW combustion turbines	2000	MMBtu/hr (approx)	Good combustion practice	3.77	LB/H	THREE ONE-HR RUNS (NATURAL GAS)	8	LB/H	THREE ONE-HR RUNS (OIL)	0		
IN-0261	VERMILLION GENERATING STATION	IN	2/28/2017	SIMPLE CYCLE, NATURAL GAS FIRED COMBUSTION TURBINES	80	MW	GOOD COMBUSTION PRACTICES	17.6	LB/H	EACH TURBINE	1.76	TON/12 CONSEC. MONTH	DETERMINED END OF EACH MONTH	0		
LA-0307	MAGNOLIA LNG FACILITY	LA	3/21/2016	Gas Turbines (8 units)	333	mm btu/hr	good combustion practices and fueled by natural gas	0			0			0		
LA-0316	CAMERON LNG FACILITY	LA	2/17/2017	Gas turbines (9 units)	1069	mm btu/hr	good combustion practices and fueled by natural gas	1.6	PPMVD	@15%O2	0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG01 CO - Simple-Cycle Combustion Turbine 1 (Commissioning) [SCN0005]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas	0			0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG02 CO - Simple-Cycle Combustion Turbine 2 (Commissioning) [SCN0006]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas	0			0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	Combustion Turbine 1 (Startup/Shutdown/ Maintenance/Tuning/Runb	2201	MM BTU/hR	Good combustion practices & use of pipeline quality natural gas	0			0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	Combustion Turbine 2 (Startup/Shutdown/ Maintenance/Tuning/Runb	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas	0			0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	Combustion Turbine 1 (Normal Operations) [EQT0017]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas	0			0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	Combustion Turbine 2 (Normal Operations) [EQT0018]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas	0			0			0		
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Aeroderivative Simple Cycle Combustion Turbine	263	MM BTU/h	Proper Equipment Design, Proper Operation, and Good Combustion Practices.	1.5	PPMV	3 HOUR AVERAGE	0			0		
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	927	MM BTU/h	Proper Equipment Design, Proper Operation, and Good Combustion Practices.	1.4	PPMV	3 HOUR AVERAGE	0			0		
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	LA	9/3/2020	Turbines (EQT0020 - EQT0031)	0		Good combustion practices	0			0			0		
MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	rated 667 MMBTU/hr natural gas-fired simple cycle CTG	667	MMBTU/H	Good combustion practices.	5	LB/H	DURING STARTUP/SHUT DOWN	0			0		
MI-0447	LBWL--ERICKSON STATION	MI	1/7/2021	EUCTGSC1-natural gas fired simple cycle CTG	667	MMBTU/H	Good combustion practices	5	LB/H	EXCEPT DURING STARTUP/SHUT DOWN	0			0		
TX-0696	ROANâ€™S PRAIRIE GENERATING STATION	TX	9/22/2014	(2) simple cycle turbines	600	MW	good combustion	1.4	PPMVD	@15% O2 GE OPTION	1	PPMVD	@15% O2 SIEMENS OPTION	0		
TX-0733	ANTELOPE ELK ENERGY CENTER	TX	5/12/2015	Simple Cycle Turbine & Generator	202	MW	Good combustion practices	2	PPMVD @ 15% O2		0			0		
TX-0764	NACOGDOCHES POWER ELECTRIC GENERATING PLANT	TX	10/14/2015	Natural Gas Simple Cycle Turbine (>25 MW)	232	MW	Pipeline quality natural gas; limited hours; good combustion practices.	2	PPMVD @ 15% O2		0			0		
TX-0768	SHAWNEE ENERGY CENTER	TX	10/9/2015	Simple cycle turbines greater than 25 megawatts (MW)	230	MW	Pipeline quality natural gas; limited hours; good combustion practices.	1.4	PPMV		0			0		
TX-0788	NECHES STATION	TX	3/24/2016	Large Combustion Turbines > 25 MW	232	MW	good combustion practices	2	PPM		0			0		
TX-0819	GAINES COUNTY POWER PLANT	TX	4/28/2017	Simple Cycle Turbine	227.5	MW	Pipeline quality natural gas; limited hours; good combustion practices	2	PPMVD	145% O2	0			0		
TX-0833	JACKSON COUNTY GENERATORS	TX	1/26/2018	Combustion Turbines	920	MW	Good combustion practices	2	PPMVD		0			0		

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AK-0088	LIQUEFACTION PLANT	AK	7/7/2022	Six Simle Cycle Gas-Fired Turbines	1113	MMBtu/hr	Oxidation catalyst and good combustion practices	2	PPMV @ 15% O2	3-HOURS	0			0		
MD-0044	COVE POINT LNG TERMINAL	MD	6/9/2014	2 COMBUSTION TURBINES	130	MW	AND PIPELINE NATURAL GAS, GOOD COMBUSTION	0.7	PPMVD @ 15% O2	AVERAGE, EXCLUDING	101.1	LB/EVENT	FOR ALL STARTUPS	0		
NJ-0086	BAYONNNE ENERGY CENTER	NJ	8/26/2016	Simple Cycle Stationary Turbines firing Natural gas	2143980	MMBTU/YR	Oxidation Catalyst, and use of natural gas as fuel for pollution	2	PPMVD@15%O 2	BASED ON ONE H BLOCK AV	1.65	LB/H	ONE H STACK TESTS EVERY 5	0		
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	turbines, simple cycle with water injection	1690	MMBTU/H	Limit the time in startup or shutdown.	0			0			0		
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Simple Cycle Turbine (EP03)	40	MW	Oxidation Catalyst	3	PPMV AT 15% O2	3-HOUR AVERAGE	3	LB/H	3-HOUR AVERAGE	14	T/YR	
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Simple Cycle Trubine (EP04)	40	MW	Oxidation Catalyst	3	PPMV AT 15% O2	3-HOUR AVERAGE	3	LB/H	3-HOUR AVERAGE	14	T/YR	
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Simple Cycle Turbine (EP05)	40	MW	Oxidation Catalyst	3	PPMV AT 15% O2	3-HOUR AVERAGE	3	LB/H	3-HOUR AVERAGE	14	T/YR	

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AL-0328	PLANT BARRY	AL	11/9/2020	Two 744 MW Combined Cycle Units	744	MW	SCR	2	PPM	3 HOUR AVG / @15% O2	39.1	LB/HR	3 HOUR AVG	0		
CT-0157	CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/12 months	SCR	2	PPMVD @15% O2	1 HR BLOCK	0			0		
CT-0158	CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/yr	SCR	2	PPMVD @15% O2	1 HR BLOCK	2	PPMVD @15% O2	1 HR BLOCK	0		
LA-0308	MORGAN CITY POWER PLANT	LA	9/26/2013	Combustion Turbine with SCR/HRSG	607.1	MMBTU/hr	Selective Catalytic Reduction (SCR) and Water/Steam Injection	11.89	LB/H	HOURLY MAXIMUM	52.07	T/YR	ANNUAL MAXIMUM	5	PPM@15% O2	12 MONTH AVERAGE
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined cylce turbine with duct burner	39463	mmcubic ft/year*	Selelctive catalytic reduction (SCR) system	2	PPMVD	3-HR ROLLING AVERAGE BASED ON 1-HR BLOCK	16.5	LB/H	AVERAGE OF THREE TESTS	0		
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined Cycle Combustion Turbine	39463	MMCubic ft/yr	Selective Catalytic Reduction (SCR) System and use of natural gas a clean burning fuel	0.75	LB/H	AVERAGE OF THREE TESTS	2	PPMVD	3-HR ROLLING AVE BASED ON 1-HR BLOCK AVE	0		
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - SIEMENS	33691	MMCF/YR	Selective Catalytic Reduction System (SCR)	2	PPMVD	3-HR ROLLING AVE BASED ON 1-HR BLOCK AVE	19.5	LB/H	AVERAGE OF THREE ONE HOUR TESTS	0		
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine without Duct Burner	20282	MMCF/YR	Selective Catalytic Reduction System (SCR) and use of natural gas a clean burning fuel	2	PPMVD@15%O2	3-HR ROLLING AVE BASED ON 1-HR BLOCK	17.33	LB/H	3-HR ROLLING AVE BASED ON 1-HR BLOCK	0		
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine with Duct Burner	20282	MMCF/YR	Selective Catalytic reduction (SCR) and use of natural gas a clean burning fuel	23	LB/H	3-HR ROLLING AVE BASED ON 1-HR BLOCK	2	PPMVD@15%O2	3-HR ROLLING AVE BASED ON 1-HR BLOCK	0		
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	Combined Cycle Power Blocks 472 MW - (2)	0		SCR	2	PPMDV		111.2	T/YR	EACH UNIT	0		
PA-0288	SUNBURY GENERATION LP/SUNBURY SES	PA	4/1/2013	Combined Cycle Combustion Turbine AND DUCT BURNER (3)	2538000	MMBTU/H	SCR	2	PPM	CORRECTED TO 15% OXYGEN	17.4	LB/H	DUCT BURNERS NOT OPERATING	18.4	LB/H	DUCT BURNERS OPERATING
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	COMBINED CYCLE UNITS #1 and #2	3.4	MMCF/HR	SCR	2	PPMVD @ 15% O2	WITH OR WITHOUT DUCT BURNER	17.25	TPY 12 MONTH ROLLING	INCLUDING START UP AND SHUR DOWN	0		
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Turbine, Combined Cycle, #1 and #2	3046	MMBTU/H	SCR	131.6	TPY	12-MONTH ROLLING TOTAL	0			0		
*PA-0298	FUTURE POWER PA/GOOD SPRINGS NGCC FACILITY	PA	3/4/2014	Turbine, COMBINED CYCLE UNIT (Siemens 5000)	2267	MMBTU/H	SCR	2	PPMVD	@ 15% OXYGEN	19.6	LB/H	WITH DUCT BURNER	79.9	TPY	BASED ON A 12-MONTH ROLLING TOTAL
TX-0709	SAND HILL ENERGY CENTER	TX	9/13/2013	Natural gas-fired combined cycle turbines	173.9	MW	SCR	2	PPM	24HR ROLLING AVG.	0			0		
VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	COMBUSTION TURBINE GENERATOR WITH DUCT-FIRED HEAT RECOVERY STEAM GENERATORS (3)	3227	MMBTU/HR	SCR	2	PPMVD	1 HR AVG	0			0		
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Combined Cycle Turbine (EP01)	40	MW	SCR	3	PPMV AT 15% O2	1-HOUR	4.6	LB/H	30-DAY ROLLING AVERAGE	25.5	T/YR	
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Combined Cycle Turbine (EP02)	40	MW	SCR	3	PPMV AT 15% O2	1-HOUR	4.6	LB/H	30-DAY ROLLING AVERAGE	25.5	T/YR	

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AK-0088	LIQUEFACTION PLANT	AK	7/7/2022	Four Combined Cycle Gas-Fired Turbines	384	MMBtu/hr	SCR, DLN combustors, and good combustion practices	2	PPMV @ 15% O2	3-HOURS	0			0		
CO-0076	PUEBLO AIRPORT GENERATING STATION	CO	12/11/2014	Four combined cycle combustion turbines	373	MMBTU/H each	SCR and dry low NOx burners	8	LB/H	4-HR ROLLING AVE / STARTUP AND SHUTDOWN	0			0		
FL-0337	POLK POWER STATION	FL	10/14/2012	Combine cycle power block (4 on 1)	1160	MW	SCR/DLN	2	PPMVD @15% O2	24-HR BLOCK (GAS) CEMS	8	PPMVD @15% O2	24-HR BLOCK (OIL) CEMS	0		
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	FL	7/27/2018	1-on-1 combined cycle unit (GE 7HA)	3266.9	MMBtu/hour	Dry low-NOX combustors and Selective Catalytic Reduction (SCR)	2	PPMVD AT 15% O2	24-HOUR BLOCK AVERAGE BASIS (BACT)	15	PPMVD AT 15% O2	30-OPERATING-DAY ROLLING AVG. (NSPS)	0		
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	FL	6/7/2021	GE 7HA.02 Combustion Turbine and HRSG with Duct Firing	3622.1	MMBtu/hour	Dry low-NOX combustors and Selective Catalytic Reduction (SCR)	2	PPMVD AT 15% O2	24-HOUR BLOCK AVERAGE BASIS (BACT)	15	PPMVD AT 15% O2	30-OPERATING-DAY ROLLING AVG. (NSPS)	0		
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	Combustion turbine #1 - combined cycle	2258	mmBtu/hr	Low-NOx burners and SCR	2	PPM	30-DAY ROLLING AVG. @15% O2	114.5	TON/YR	12-MONTH ROLLING TOTAL	0		
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	Combustion turbine #2 - combined cycle	2258	mmBtu/hr	SCR, Low-NOx burner	2	PPM	30-DAY ROLLING AVERAGE	114.5	TON/YR	12-MONTH ROLLING TOTAL	0		
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Combined Cycle Combustion Turbines	3474	mmBtu/hr	Selective catalytic reduction (SCR) and low-NOx combustion technology (dry low-NOx combustion technology for natural gas; water injection for ULSD)	2	PPMV @ 15% O2	3-UNIT OPERATING HOURS	5	PPMV @ 15% O2	3-UNIT OPERATING HOURS	0		
IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Combined-Cycle Combustion Turbine	3864	mmBtu/hr	Selective Catalytic Reduction (SCR) and low-NOx technology (dry low-NOx combustion technology)	2	PPMV	3-UNIT OPERATING HOURS @ 15% O2	2	PPMV	1-UNIT OPERATING HOUR @ 15% O2	0		
IL-0133	LINCOLN LAND ENERGY CENTER	IL	7/29/2022	Combined-Cycle Combustion Turbines	3647	mmBtu/hour	Dry low-NOx combustion with ultra-low NOx combustors; low-NOx duct burners; and selective catalytic reduction (SCR)	2	PPMV @ 15% O2	SEE NOTES	0		SEE NOTES	0		
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Combined Cycle Combustion Turbines (CCCT1 to CCCT5)	921	MM BTU/h	Low NOx Burners, SCR, and Good Combustion Practices	2.5	PPMV	30 DAY ROLLING AVERAGE	0			0		
LA-0364	FG LA COMPLEX	LA	1/6/2020	Cogeneration Units	2222	mm btu/h	Dry low NOx combustor design along with SCR.	2	PPMVD	12-MONTH ROLLING AVERAGE	0			0		
*LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	LA	6/3/2022	Combined Cycle Gas Turbine w/ Duct Burners and HRSG	5081	mm BTU/h	Dry low-NOx combustor design, selective catalytic reduction (SCR), and good combustion practices.	2	PPMVD	24-HR ROLLING AVG BASED ON 1-HR AVG	0			0		
MD-0041	CPV ST. CHARLES	MD	4/23/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	725	MEGAWATT	DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)	2	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD	123	LB/EVENT	CEM	0		
MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITH DUCT FIRING	1000	MW	USE OF DRY LOW-NOX COMBUSTOR TURBINE DESIGN , USE OF PIPELINE QUALITY NATURAL GAS DURING NORMAL OPERATION AND SCR SYSTEM	2	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD	870	LB/EVENT	FOR ALL STARTUPS	0		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - COLD STARTUP	286	MW	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)	153	LB/EVENT	COLD STARTUP	0			0		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES	286	MW	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)	2	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE (EXCLUDING SU/SD)	42	PPM @ 15% O2	3-HOUR BLOCK AVERAGE	0		

MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - WARM STARTUP	286	MW	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)	132	LB/EVENT	WARM STARTUP	0			0		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - HOT STARTUP	286	MW	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)	105	LB/EVENT	HOT STARTUP	0			0		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - SHUTDOWN	286	MW	DRY LOW-NOX COMBUSTOR DESIGN, GOOD COMBUSTION PRACTICES AND SELECTIVE CATALYTIC REDUCTION (SCR)	23	LB/EVENT	SHUT DOWN	0			0		
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES - COLD STARTUP	235	MW	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)	245.2	LB/EVENT	COLD STARTUP	0			0		
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES - WARM STARTUP	235	MW	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)	82.9	LB/EVENT	WARM STARTUP	0			0		
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG	2237	MMBTU/H	Dry low NOx (DLN) burner and selective catalytic reduction (SCR) system.	2	PPM	EACH CTG; 24-H ROLLING AVG.	16.2	LB/H	EACH CTG; 24-H ROLLING AVG.	0		
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG and duct burner (DB)	2486	MMBTU/H	Dry low NOx (DLN) burners and selective catalytic reduction (SCR) system.	2	PPM	24-H ROLLING AVG	18	LB/H	24-H ROLLING AVG	0		
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG--Startup/Shutdown	2237	MMBTU/H each	Dry low NOx (DLN) burner and selective catalytic reduction (SCR)	185.7	LB/H	HOURLY DURING STARTUP	134	LB/H	HOURLY DURING SHUTDOWN	0		
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG1-4 Natural gas fueled combined cycle combustion turbine generators (CTG)	2147	MMBTU/H	Dry Low NOx burners (DLN) and Selective Catalytic Reduction (SCR) system.	2	PPMVOL	3-H ROLL AVG., EXCEPT STARTUP/SHUT DOWN	18.6	PPH	24-H ROLL AVG., EXCEPT STARTUP/SHUT DOWN	0		
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG/DB1-4 Natural gas fueled combined cycle combustion turbine generators; duct burner on HRSG	2807	MMBTU/H	Dry low NOx burner (DLN) and selective catalytic reduction system (SCR).	2	PPMVOL	3-H ROLL AVG., EXCEPT STARTUP/SHUT DOWN	23.7	PPH	24-H ROLL AVG., EXCEPT STARTUP/SHUT DOWN	0		
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: 2 Combined cycle CTGs with HRSGs with duct burners	647	MMBTU/H for each CTGHRSG	SCR with DLNB (selective catalytic reduction with dry low NOx burners).	3	PPM	24-H ROLL.AVG. NOT STARTUP/SHUT DOWN	8.18	LB/H	24-H ROLL.AVG. NOT STARTUP/SHUT DOWN	0		
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: Startup & Shutdown	647	MMBTU/H for each CTGHRSG	SCR with DLNB (selective catalytic reduction with dry low NOx burners).	43.7	LB/H	OPERATING HOUR DURING STARTUP	43.1	LB/H	OPERATING HOUR DURING SHUTDOWN	0		
MI-0423	INDECK NILES, LLC	MI	1/4/2017	FGCTGHRSG (2 Combined Cycle CTGs with HRSGs)	8322	MMBTU/H	SCR with DLNB (selective catalytic reduction with dry low NOx burners)	38.1	LB/H	24-H ROLLING AVERAGE	286	LB/H	OPERATING HR DURING STARTUP OR SHUTDOWN	0		
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	FGCTGHRSG (2 Combined cycle CTGs with HRSGs; EUCTGHRSG10 & EUCTGHRSG11)	554	MMBTU/H, each	Selective catalytic reduction with dry low NOx burners (SCR with DLNB).	3	PPM AT 15% O2	24-H ROLLING AVG; EACH EU	8.18	LB/H	24-H ROLLING AVG; EACH EU	0		
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	FGCTGHRSG--Startup/Shutdown (2 combined cycle CTGs with HRSGs; EUCTGHRSG10 & EUCTGHRSG11)	554	MMBTU/H; EACH	Selective catalytic reduction with dry low NOx burners (SCR with DLNB).	43.7	LB/H	OPERATING HOUR DURING STARTUP; EACH EU	43.1	LB/H	OPERATING HOUR DURING SHUTDOWN; EACH EU	0		

MI-0427	FILER CITY STATION	MI	11/17/2017	EUCCT (Combined cycle CTG with unfired HRSG)	1934.7	MMBTU/H	SCR with DLNB (Selective catalytic reduction with dry low NOx burners).	3	PPM	24-H ROLL.AVG., EXCEPT STARTUP/SHUT DOWN	21.4	LB/H	24-H ROLL.AVG., EXCEPT STARTUP/SHUT DOWN	0		
MI-0431	INDECK NILES LLC	MI	6/26/2018	FGCTGHRSG (2 Combined Cycle CTG with HRSGs)	3421	MMBTU/H	SCR with DLNB (Selective Catalytic Reduction with Dry Low NOx Burners)	2	PPM	AT 15%O2; 24-HR ROLL AVG	38.1	LB/H	24-HR ROLL AVG.	0		
MI-0432	NEW COVERT GENERATING FACILITY	MI	7/30/2018	FG-TURB/DB1-3 (3 combined cycle combustion turbine and heat recovery steam generator trains)	1230	MW	Good combustion practices, DLN burners and SCR.	2	PPMVD	AT 15%O2; EACH INDIV. CT/HRSG TRAIN	22.4	LB/H	EACH INDIV. CT/HRSG TRAIN; 24-H ROLL AVG	0		
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUCTGHRSG (South Plant): A combined cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	500	MW	SCR with DLNB (Selective catalytic reduction with dry low NOx burners).	2	PPMV	AT 15%O2; 24-HR ROLL AVG NOT S.S.	29.7	LB/H	24-H ROLL AVG NOT S.S.	0		
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUCTGHRSG (North Plant): A combined-cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	500	MW	SCR with DLNB (Selective catalytic reduction with Dry Low NOx burners).	2	PPMVD	AT 15%O2; 24-H ROLL AVG; NOT S.S.	29.7	LB/H	24-H ROLL AVG; NOT STARTUP/SHUT DOWN (SS)	0		
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	FGCTGHRSG (EUCTGHRSG1 & EUCTGHRSG2)	0		SCR with DLNB (Selective catalytic reduction with dry low NOx burners).	2	PPMVD	AT 15%O2; 24-H ROLL AVG; EACH UNIT;	28.9	LB/H	24-H ROLL AVG; EACH UNIT; NOT S.S.	0		
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	FGCTGHRSG (EUCTGHRSG1 & EUCTGHRSG2)--Startup & Shutdown	0		SCR with DLNB (Selective catalytic reduction with dry low NOx burners).	262.4	LB/H	EACH UNIT; OPERATING HOUR DURING S.S.	0			0		
*MI-0451	MEC NORTH, LLC	MI	6/23/2022	EUCTGHRSG (North Plant): A combined cycle natural gas fired combustion turbine generator with heat recovery steam generator	3064	MMBTU/H	SCR with DLNB (Selective catalytic reduction with Dry low NOx burners)	2.5	PPM	24-HR ROLLING AVG	29.2	LB/H	24-HR ROLLING AVG	0		
*MI-0452	MEC SOUTH, LLC	MI	6/23/2022	EUCTGHRSG (South Plant): A combined-cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	3064	MMBTU/H	SCR with DLNB [Selective Catalytic Reduction with Dry Low NOx Burners]	2	PPM	24-HR ROLLING AVG	29.2	LB/H	24-HR ROLLING AVG EXCEPT SU/SD	0		
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Combined Cycle Combustion Turbine w/o duct burner	40297.6	mmcubic ft/year	DLN combustion system with SCR on each of the two combustion turbines and use of only natural gas as fuel.	2	PPMVD	3-HR ROLLING AVE BASED ON 1-HR BLOCK	16.8	LB/H	AVERAGE OF THREE TESTS	0		
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	Selective Catalytic Reduction Systems(SCR) and Dry Low NOx	2	PPMVD@15%O2	3-HR BLOCK AVERAGE BASED ON 1-HR BLOCK	18.1	LB/H	AVERAGE OF THREE ONE HOUR TESTS	0		
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITHOUT DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	Selective Catalytic Reduction System (SCR) and Dry Low NOx	2	PPMVD@15%O2	3-HR ROLLING AVERAE BASED ON 1-HR BLOCK	16.8	LB/H	AVERAGE OF THREE ONE-HOUR TESTS	0		
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, without duct burners	515600	MMSCF/rolling 12-months	selective catalytic reduction (SCR); dry low NOx combustors; lean fuel technology	22	LB/H		92	T/YR	PER ROLLING 12-MONTHS	2	PPM	PPMVD AT 15% O2
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, with duct burners	51560	MMSCF/rolling 12-MO	selective catalytic reduction (SCR); dry low NOx combustors; lean fuel technology	21	LB/H		92	T/YR	PER ROLLING 12-MONTHS	2	PPM	PPMVD AT 15% O2
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, without duct burners	47917	MMSCF/rolling 12-MO	selective catalytic reduction (SCR); dry low NOx combustors; lean fuel technology	22.6	LB/H		94.8	T/YR	PER ROLLING 12-MONTHS	2	PPM	PPMVD AT 15% O2

OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, with duct burners	47917	MMSCF/rolling 12-MO	selective catalytic reduction (SCR); dry low NOx combustors; lean fuel technology	20.8	LB/H		94.8	T/YR	PER ROLLING 12-MONTHS	2	PPM	PPMVD AT 15% O2
OH-0360	CARROLL COUNTY ENERGY	OH	11/5/2013	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	2045	MMBTU/H	selective catalytic reduction (SCR) and dry low NOx combustors	20.5	LB/H	WITH DUCT BURNER. SEE NOTES.	103.2	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	2	PPM	BY VOLUME AT 15% O2
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	8/25/2015	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	2725	MMBTU/H	dry low NOx combustors, selective catalytic reduction (SCR)	23.5	LB/H	WITH DUCT BURNER. SEE NOTES.	107.2	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
OH-0367	SOUTH FIELD ENERGY LLC	OH	9/23/2016	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	3131	MMBTU/H	Dry low NOx (DLN) burners for natural gas firing, wet injection when firing ultra low sulfur diesel, and selective catalytic reduction (SCR) for both natural gas and ultra low sulfur diesel.	30.51	LB/H	WITH DUCT BURNER. SEE NOTES.	151.3	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
OH-0370	TRUMBULL ENERGY CENTER	OH	9/7/2017	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	3025	MMBTU/H	dry low NOx combustors (DLN) and selective catalytic reduction (SCR)	25.3	LB/H	WITH DUCT BURNER. SEE NOTES.	117.6	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
OH-0372	OREGON ENERGY CENTER	OH	9/27/2017	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	3055	MMBTU/H	Dry low NOX combustors and selective catalytic reduction (SCR)	25.3	LB/H	WITH DUCT BURNER. SEE NOTES.	118.02	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
OH-0374	GUERNSEY POWER STATION LLC	OH	10/23/2017	Combined Cycle Combustion Turbines (3, identical) (P001 to P003)	3516	MMBTU/H	dry low NOx burners and SCR	33.85	LB/H	WITH DUCT BURNER. SEE NOTES.	26.37	LB/H	WITHOUT DUCT BURNERS. SEE NOTES.	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	Combined-cycle Turbines (2) - Natural gas fired	3277	MMBTU/H	Dry low-NOx (DLN) combustor and selective catalytic reduction (SCR)	2	PPMVD		0			0		
PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	PA	6/15/2015	Two Combine Cycle Combustion Turbine with Duct Burner	3001.57	MCF/hr	SCR, Dry Lo-NOx combustor, good combustion practices and low sulfur fuels	2	PPVDM @ 15 O2		358.9	TONS	ANY 12-MONTH PERIOD	0		
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	Combustion turbine with duct burner	3304.3	MMBtu/hr	Dry low-NOx burners, SCR, exclusive natural gas	2	PPMDV @15% O2		100.3	TONS	YEAR	0		
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Combustion turbine and HRSG with duct burner NG only	3338	MMBtu/hr	Dry Low NOx combustion technology, SCR at all steady state operating loads, good combustion and operating practices	2	PPMDV @ 15% O2		233.3	TONS	12-MONTH ROLLING BASIS	0		
PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Combustion Turbine With Duct Burner	3727	MMBtu/hr	DLN burner, SCR, good engineering practice	2	PPMDV @ 15% O2		25.7	LB/HR		0		
TX-0689	CEDAR BAYOU ELECTRIC GENERATION STATION	TX	8/29/2014	Combined cycle natural gas turbines	225	MW	DLN, SCR	2	PPM	24HR ROLLING AVG.	0			0		
TX-0819	GAINES COUNTY POWER PLANT	TX	4/28/2017	Combined Cycle Turbine with Heat Recovery Steam Generator, fired Duct Burners, and Steam Turbine Generator	426	MW	Selective Catalytic Reduction (SCR) and Dry Low NOx burners	2	PPMVD	15% O2 3-H AVG	0			0		
TX-0834	MONTGOMERY COUNTY POWER STATIOIN	TX	3/30/2018	Combined Cycle Turbine	2635	MMBTU/HR/UNIT	SCR and Dry Low NOx burners	2	PPMVD	15% O2 1-HOUR AVERAGE	0			0		
*VA-0335	PANDA STONEWALL LLC	VA	12/18/2020	Combustion Turbines, Two (2) and HRSG Duct Burners	2.55	MMBTU/H	Selective Catalytic Reduction (SCR), with ammonia injection and dry low NOx combustion.	2	PPMVD @ 15% O2	W & W/O DUCT BURNING	0			0		
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Natural-Gas-Fired Combined-Cycle Turbine (P01)	4671	MMBTU/H	Selective Catalytic Reduction (SCR), low-NOx burners, Water injection when firing diesel fuel oil.	2	PPM AT 15% O2	24-HR ROLLING AVG., NATURAL GAS	6	PPM AT 15% O2	24-HR ROLLING AVG., DIESEL	0		
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Combined Cycle Turbine/Duct Burner	2419.61	mmBtu/Hr	SCR & Dry Low-NOx Burners	15.2	LB/H		0			2	PPM	@ 15% O2
*WV-0033	MAIDSVILLE	WV	1/5/2022	Combustion Turbine & Duct Burner (CT-01/HRSG1 & CT-02/HRSG2)	1275	mw	Dry Low NOx Combustion w/ SCR	2	PPMDV @ 15% O2	3-HOUR ROLLING AVERAGE	32.09	LB/HR	3-HOUR ROLLING AVERAGE	0.43	LB/MWH GROSS	30 OPERATING DAY ROLLING AVG.
*WV-0033	MAIDSVILLE	WV	1/5/2022	Combustion Turbine & Duct Burner (CT-01/HRSG1 & CT-02/HRSG2)	1275	mw	Dry Low NOx Combustor with SCR	2	PPMDV @ 15% O2	3-HOUR ROLLING AVERAGE	34.09	LB/HR	3-HOUR ROLLING AVERAGE	0.43	LB/MWH GROSS	30 OPERATING DAY ROLLING AVG.

RBLCID	FACILITY NAME	STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	UNITS	CONTROL METHOD	EMISSION LIMIT 1	UNITS	AVERAGING TIME	EMISSION LIMIT 2	UNITS	AVERAGING TIME	STANDARD EMISSION LIMIT	UNITS	AVERAGING TIME
*LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	LA	6/3/2022	Combined Cycle Gas Turbine Startup and Shutdown	5081	mm BTU/h	Good combustion practices.	520	LB/HR		0			0		
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG	2237	MMBTU/H	Good combustion practices	0.0018	LB/MMBTU	EACH CTG; TEST PROTOCOL	0			0		
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG and duct burner (DB)	2486	MMBTU/H	Good combustion practices	0.004	LB/MMBTU	TEST PROTOCOL	0			0		
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	Combined Cycle Combustion Turbine - Siemens turbine without Duct Burner	33691	MMCF/YR	Good Combustion Practices and use of Natural gas as a clean burning fuel	1	PPMVD@ 15%O2	AVERAGE OF THREE TESTS	6.4	LB/H	AVERAGE OF THREE TESTS	0		
TX-0618	CHANNEL ENERGY CENTER LLC	TX	10/15/2012	Combined Cycle Turbine	180	MW	Good combustion	2	PPMVD	@15% O2	0			0		
TX-0619	DEER PARK ENERGY CENTER	TX	9/26/2012	Combined Cycle Turbine	180	MW	good combustion, use of natural gas	2	PPMVD	@15% O2	0			0		
TX-0620	ES JOSLIN POWER PLANT	TX	9/12/2012	Combined cycle gas turbine	195	MW	good combustion and natural gas as fuel	2	PPMVD	@15% O2	0			0		

RBLCID	FACILITY NAME	STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	UNITS	CONTROL METHOD	EMISSION LIMIT 1	UNITS	AVERAGING TIME	EMISSION LIMIT 2	UNITS	AVERAGING TIME	STANDARD EMISSION LIMIT	UNITS	AVERAGING TIME
AK-0088	LIQUEFACTION PLANT	AK	7/7/2022	Four Combined Cycle Gas-Fired Turbines	384	MMBtu/hr	Oxidation catalyst and good combustion practices	2	PPMV @ 15% O2	3-HOURS	0			0		
AL-0328	PLANT BARRY	AL	11/9/2020	Two 744 MW Combined Cycle Units	744	MW	Oxidation Catalyst	13.6	LB/HR	3 HOUR AVG	0.003	LB/MMBTU	3 HOUR AVG	0		
CT-0157	CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/12 months	Oxidation Catalyst	1	PPMVD @15% O2		2	PPMVD @15% O2		0		
CT-0158	CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/yr	Oxidation Catalyst	1	PPMVD @15% O2		2	PPMVD @15% O2		0		
IL-0133	LINCOLN LAND ENERGY CENTER	IL	7/29/2022	Combined-Cycle Combustion Turbines	3647	mmBtu/hour	Oxidation catalyst and good combustion practices.	1	PPMV, ADJ. TO 15% O2	ROLLING 3-OPERATING HOUR	1.1	PPMV, ADJ. TO 15% O2	ROLLING 3-OPERATING HOUR	0		
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES	2300	MMBTU/H	OXIDIZED CATALYST	1	PPMVD	3 HOURS	2	PPMVD	3 HOURS	0		
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Combined Cycle Combustion Turbines (CCCT1 to CCCT5)	921	MM BTU/h	Catalytic Oxidation, Proper Equipment Design and Good Combustion Practices.	1.1	PPMV	3 HOUR AVERAGE	0			0		
LA-0364	FG LA COMPLEX	LA	1/6/2020	Cogeneration Units	2222	mm btu/h	Good combustion practices and catalytic oxidation	4	PPMVD		0			0		
*LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	LA	6/3/2022	Combined Cycle Gas Turbine w/ Duct Burners and HRSG	5081	mm BTU/h	Catalytic oxidation and good combustion practices.	1	PPMVD	3 1-HR TEST AVERAGE	2	PPMVD	3 1-HR TEST AVERAGE	0		
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Combustion Turbine with Duct Burner	2449	MMBTU/H	Oxidation catalyst	1	PPMVD@15% O2	1 HR AVG EXCLUDING SS/NO DUCT FIRING	1.7	PPMVD@15% O2	1 HR AVG EXCLUDING SS/DUCT FIRING	0		
MD-0041	CPV ST. CHARLES	MD	4/23/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	725	MEGAWATT	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD	2	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD	0		
MD-0041	CPV ST. CHARLES	MD	4/23/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITH DUCT FIRING	725	MW	EXCLUSIVE USE OF NATURAL GAS, AND AN OXIDATION CATALYST	2	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD	7.6	LB/H	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD	0		
MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITH DUCT FIRING	1000	MW	USE OF PIPELINE NATURAL GAS, GOOD COMBUSTION PRACTICES, AND USE OF AN OXIDATION CATALYST	1.6	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD	6720	LB/EVENT	COLD STARTUP	0		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - COLD STARTUP	286	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	301	LB/EVENT	COLD STARTUP	0			0		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES	286	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1	PPMVD @ 15% O2	3-HR BLOCK AVG. W/OUT DUCT FIRING	1.9	PPMVD @ 15% O2	3-HR BLOCK AVG. WITH DUCT FIRING	0		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - WARM STARTUP	286	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	258	LB/EVENT	WARM STARTUP	0			0		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - HOT STARTUP	286	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	207	LB/EVENT	HOT STARTUP	0			0		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - SHUTDOWN	286	MW	GOOD COMBUSTION PRACTICES AND OXIDATION CATALYST	63	LB/EVENT	SHUTDOWN	0			0		
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	235	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1	PPMVD @ 15% O2	W/OUT DUCT FIRING, 3-HR BLOCK AVG	2	PPMVD @ 15% O2	WITH DUCT FIRING, 3-HR BLOCK AVG	0		
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES - COLD STARTUP	235	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	164	LB/EVENT	COLD STARTUP	0			0		
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES - WARM STARTUP	235	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	63	LB/EVENT	WARM STARTUP	0			0		
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES - HOT STARTUP	235	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	52.6	LB/EVENT	HOT STARTUP	0			0		
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES - SHUTDOWN	235	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	12	LB/EVENT	SHUTDOWN	0			0		

MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG1-4 Natural gas fueled combined cycle combustion turbine generators (CTG)	2147	MMBTU/H	Catalytic oxidation system (COS)	2	PPMVOL	DRY AT 15% OXYGEN	0			0		
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG/DB1-4 Natural gas fueled combined cycle combustion turbine generators; duct burner on HRSG	2807	MMBTU/H	Catalytic oxidation system (COS)	2	PPMVOL	DRY AT 15% OXYGEN	0			0		
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: 2 Combined cycle CTGs with HRSGs with duct burners	647	MMBTU/H for each CTGHRSG	Oxidation catalyst technology and good combustion practices.	4	PPM	TEST PROTOCOL	0			0		
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: Startup & Shutdown	647	MMBTU/H for each CTGHRSG	Oxidation catalyst technology and good combustion practices.	198.9	LB/H	EACH, DURING STARTUP	419.7	LB/H	EACH, DURING SHUTDOWN	0		
MI-0423	INDECK NILES, LLC	MI	1/4/2017	FGCTGHRSG (2 Combined Cycle CTGs with HRSGs)	8322	MMBTU/H	Oxidation Catalyst Technology and Good Combustion Practices	4	PPM	TEST PROTOCOL WILL SPECIFY	0			0		
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	FGCTGHRSG (2 Combined cycle CTGs with HRSGs; EUCTGHRSG10 & EUCTGHRSG11)	554	MMBTU/H, each	Oxidation catalyst technology and good combustion practices.	4	PPM AT 15% O2	TEST PROTOCOL WILL SPECIFY AVG TIME	0			0		
MI-0432	NEW COVERT GENERATING FACILITY	MI	7/30/2018	FG-TURB/DB1-3 (3 combined cycle combustion turbine and heat recovery steam generator trains)	1230	MW	An oxidation catalyst and good combustion practices.	1	PPMVD	HOURLY; EACH CT/HRSG TRAIN	48	T/YR	EACH CT/HRSG TRAIN; 12-MO ROLL TIME PER.	0		
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUCTGHRSG (South Plant): A combined cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	500	MW	Oxidation catalyst technology and good combustion practices.	4	PPMVD	AT 15%O2; NOT INCL. STARTUP/SHUT DOWN	0			0		
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUCTGHRSG (North Plant): A combined-cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	500	MW	Oxidation catalyst technology and good combustion practices.	4	PPMVD	AT 15%O2; HOURLY	0			0		
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	FGCTGHRSG (EUCTGHRSG1 & EUCTGHRSG2)	0		Oxidation catalyst technology and good combustion practices.	0.0026	LB/MMBTU	EACH UNIT; HOURLY EXCEPT S.S.	0.0013	LB/MMBTU	EACH UNIT W/O DUCT BURNER FIRING; NOT SS	0		
MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUCTGHRSG2--A 667 MMBTU/H natural gas fired CTG with a HRSG.	667	MMBTU/H	An oxidation catalyst for VOC control and good combustion practices.	3	PPM	PPMVD@15%O2; HOURLY; SEE NOTES	5	LB/H	HOURLY EXCEPT STARTUP/SHUT DOWN; SEE NOTE	0		
MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUCTGHRSG1--A 667 MMBTU/H NG fired combustion turbine generator coupled with a heat recovery steam generator (HRSG)	667	MMBTU/H	An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices.	3	PPM	PPMVD@15%O2; HOURLY EXC.START/SHUT; NOTE	5	LB/H	HOURLY EXCEPT STARTUP/SHUT DOWN; SEE NOTE	0		
MI-0447	LBWL--ERICKSON STATION	MI	1/7/2021	EUCTGHRSG1	667	MMBTU/H	An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices.	3	PPM	HOURLY EXCEPT STARTUP SHUTDOWN	5	LB/H	HOURLY EXCEPT STARTUP SHUTDOWN	0		
MI-0447	LBWL--ERICKSON STATION	MI	1/7/2021	EUCTGHRSG2	667	MMBTU/H	An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices.	3	PPM	HOURLY; EXCEPT DURING STARTUP/SHUT DOWN	5	LB/H	HOURLY EXCEPT DURING STARTUP/SHUT DOWN	0		
*MI-0451	MEC NORTH, LLC	MI	6/23/2022	EUCTGHRSG (North Plant): A combined cycle natural gas fired combustion turbine generator with heat recovery steam generator	3064	MMBTU/H	Oxidation catalyst technology and good combustion practices.	2	PPM	HOURLY	0			0		

*MI-0452	MEC SOUTH, LLC	MI	6/23/2022	EUCTGHRSG (South Plant): A combined-cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	3064	MMBTU/H	Oxidation Catalyst Technology and Good Combustion Practices	2	PPM	HOURLY	0			0		
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Combined Cycle Combustion Turbine with Duct Burner	40297.6	mmcubic ft/year	oxidation Catalyst and Good Combustion Practices and use of Clean fuel (Natural gas)	2	PPMVD	3-HR ROLLING AVERAGE BASED ON 1-HR BLK	6.9	LB/H	AVERAGE OF THREE TESTS.	0		
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Combined Cycle Combustion Turbine w/o duct burner	40297.6	mmcubic ft/year	Oxidation catalyst and good combustion practices, use of natural gas a clean burning fuel	2.9	LB/H	AVERAGE OF THREE TESTS	1	PPMVD	3H ROLLING AVE BASED ON 1H BLOCKS	0		
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined cylce turbine with duct burner	39463	mmcubic ft/year*	Oxidation catalyst	1	PPMVD	3-HR ROLLING AVERAGE BASED ON 1-HR BLOCK	5.7	LB/H	AVERAGE OF THREE TESTS	0		
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined Cycle Combustion Turbine	39463	MMCubic ft/yr	Oxidation Catalyst and Good combustion Practices and use of natural gas a clean burning fuel	2.9	LB/H	AVERAGE OF THREE TESTS	1	PPMVD	3-HR ROLLING AVERAGE BASED ON 1-HR BLOCK	0		
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - SIEMENS	33691	MMCF/YR	Oxidation catalyst and pollution prevention (use of natural gas a clean burning fuel)	2	PPMVD	AVERAGE OF THREE ONE HOUR TESTS	6.6	LB/H	AVERAGE OF THREE ONE HOUR TESTS	0		
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	CO Oxidation Catalyst and good combustion practices and use natural gas only as a clean burning fuel	2	PPMVD@15%O2	AVERAGE OF THREE ONE HOUR TESTS	7.2	LB/H	AVERAGE OF THREE ONE HOUR TESTS	0		
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITHOUT DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	Oxidation Catalyst and use of natural gas a clean burning fuel	1	PPMVD@15%O2	AVERAGE OF THREE ONE-HOUR TESTS	2.9	LB/H	AVERAGE OF THREE ONE-HOUR TESTS	0		
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine without Duct Burner	20282	MMCF/YR	Oxidation catalysts and use of Natural gas a clean burning fuel	0.7	PPMVD215%O2	AVERAGE OF THREE ONE HOUR STACK TESTS	2.11	LB/H	AVERAGE OF THREE ONE HOUR STACK TESTS	0		
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine with Duct Burner	20282	MMCF/YR	Oxidation catalyst and use of natural gas a clean burning fuel	1	PPMVD@15%O2	AVERAGE OF THREE STACK TEST RUNS	4	LB/H	AVERAGE OF THREE STACK TEST RUNS	0		
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas with Duct Burner	4000	h/yr	Oxidation Catalyst and good combustion practices	2	PPMVD@15%O2	AV OF THREE ONE H STACK TESTS EVERY 5 YR	10.3	LB/H	AV OF THREE ONE H STACK TESTS EVERY 5 YR	0		
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas without Duct Burner	8040	H/YR	Oxidation catalyst and good combustion practices	1	PPMVD@15%O2	AV OF THREE ONE H STACK TESTS EVERY 5 YR	4.37	LB/H	AV OF THREE ONE H STACK TESTS EVERY 5 YR	0		
NJ-0088	COGEN TECH LINDEN VENTURE LP	NJ	7/30/2019	250 MW COMBINED CYCLE COMBUSTION TURBINE FIRING NATURAL GAS	21042	MMCubic ft/yr	Add on Oxidation Catalyst and use of Natural Gas as primary fuel for pollution prevention	3.2	LB/H	AV OF THREE ONE H STACK TESTS EVERY 5 YR	1	PPMVD@15% O2	3 H ROLLING AV BASED ON ONE H BLOCK	0		
NY-0104	CPV VALLEY ENERGY CENTER	NY	8/1/2013	Turbines and duct burners - NG	0		Good combustion practice and oxidation catalyst.	0.7	PPMVD @ 15% O2	1 H	0			0		
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines- Siemens, without duct burners	515600	MMSCF/rolling 12-months	oxidation catalyst	3.9	LB/H		28.6	T/YR	PER ROLLING 12 MONTHS	1	PPM	PPMVD AT 15% O2
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines- Siemens, with duct burners	51560	MMSCF/rolling 12-MO	oxidation catalyst	5.9	LB/H		28.6	T/YR	PER ROLLING 12-MONTHS	1.9	PPM	PPMVD AT 15% O2
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines- Mitsubishi, without duct burners	47917	MMSCF/rolling 12-MO	oxidation catalyst	7.9	LB/H		56	T/YR	PER ROLLING 12-MONTHS	2	PPM	PPMVD AT 15% O2
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines- Mitsubishi, with duct burners	47917	MMSCF/rolling 12-MO	oxidation catalyst	7.3	LB/H		56	T/YR	PER ROLLING 12-MONTHS	2	PPM	PPMVD AT 15% O2

OH-0360	CARROLL COUNTY ENERGY	OH	11/5/2013	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	2045	MMBTU/H	oxidation catalyst	7.1	LB/H	WITH DUCT BURNER. SEE NOTES.	40.2	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	0		SEE NOTES
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	8/25/2015	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	2725	MMBTU/H	Good combustion controls and oxidation catalyst	8.2	LB/H	WITH DUCT BURNER. SEE NOTES.	47.1	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
OH-0367	SOUTH FIELD ENERGY LLC	OH	9/23/2016	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	3131	MMBTU/H	Good combustion controls and oxidation catalyst	10.64	LB/H	WITH DUCT BURNER. SEE NOTES.	50.6	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
OH-0370	TRUMBULL ENERGY CENTER	OH	9/7/2017	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	3025	MMBTU/H	Good combustion controls and oxidation catalyst	8.8	LB/H	WITH DUCT BURNER. SEE NOTES.	50.3	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
OH-0372	OREGON ENERGY CENTER	OH	9/27/2017	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	3055	MMBTU/H	oxidation catalyst and good combustion control	8.8	LB/H	WITH DUCT BURNER. SEE NOTES.	50.28	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
OH-0374	GUERNSEY POWER STATION LLC	OH	10/23/2017	Combined Cycle Combustion Turbines (3, identical) (P001 to P003)	3516	MMBTU/H	oxidation catalyst and good combustion practices as recommended by the manufacturer	11.73	LB/H	WITH DUCT BURNER. SEE NOTES.	4.92	LB/H	WITHOUT DUCT BURNERS. SEE NOTES.	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	Combined-cycle Turbines (2) - Natural gas fired	3277	MMBTU/H	Oxidation Catalyst	1	PPMVD	WITHOUT DUCT BURNER	1.5	PPMVD	WITH DUCT BURNER	0		
PA-0288	SUNBURY GENERATION LP/SUNBURY SES	PA	4/1/2013	Combined Cycle Combustion Turbine AND DUCT BURNER (3)	2538000	MMBTU/H	Oxidation Catalyst	1	PPM	3 LB/HR, DUCT BURN NOT OPERATING, 15% O2	3.9	PPM	10.8 LB/HR, DUCT BURN OPERATING, 15% O2	0		
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	COMBINED CYCLE UNITS #1 and #2	3.4	MMCF/HR	Oxidation Catalyst	1.5	PPMVD @ 15% OXYGEN	WITH OR WITHOUT DUCT BURNER	93.44	TPY 12-MONTH ROLLING	INCLUDING STARTUP AND SHUTDOWN	0		
PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	PA	6/15/2015	Two Combine Cycle Combustion Turbine with Duct Burner	3001.57	MCF/hr	Oxidation catalyst, good combustion practices and low sulfur fuels	1.9	PPMDV @ 15% O2		256.4	TONS	ANY 12-MONTH PERIOD	0		
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	Combustion turbine with duct burner	3304.3	MMBtu/hr	Oxidation catalyst, combustion controls, exclusive natural gas	1.5	PPMDV @ 15% O2		24.6	TONS	YEAR	0		
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Combustion turbine and HRSG with duct burner NG only	3338	MMBtu/hr	Oxidation catalyst and good combustion practices	1.5	PPMDV @ 15% O2		64.2	TONS	12-MONTH ROLLING BASIS	0		
PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Combustion Turbine With Duct Burner	3727	MMBtu/hr	Oxidation catalyst and good engineering practice	1.5	PPMDV @ 15% O2		8.93	LB/HR		0		
TX-0641	PINECREST ENERGY CENTER	TX	11/12/2013	combined cycle turbine	700	MW	oxidation catalyst	2	PPMVD	INITIAL STACK TEST, 15% OXYGEN	0			0		
TX-0708	LA PALOMA ENERGY CENTER	TX	2/7/2013	(2) combined cycle turbines	650	MW	oxidation catalyst	2	PPMVD	@15% O2, 3-HR ROLLING	0			0		
TX-0710	VICTORIA POWER STATION	TX	12/1/2014	combined cycle turbine	197	MW	oxidation catalyst	4	PPMVD	@15% O2, 3-HR ROLLING AVERAGE	0			0		
TX-0712	TRINIDAD GENERATING FACILITY	TX	11/20/2014	combined cycle turbine	497	MW	oxidation catalyst	4	PPMVD	@15% O2 1-HR	0			0		
TX-0713	TENASKA BROWNSVILLE GENERATING STATION	TX	4/29/2014	(2) combined cycle turbines	274	MW	oxidation catalyst	2	PPMVD	@15% O2, 3-HR AVERAGE	0			0		
TX-0714	S R BERTRON ELECTRIC GENERATING STATION	TX	12/19/2014	(2) combined cycle turbines	240	MW	oxidation catalyst	1	PPMVD	@15% O2	0			0		
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	TX	6/18/2015	Combined Cycle Turbines (>25 MW) â€" natural gas	210	MW	Oxidation catalyst	2	PPM		0			0		
TX-0767	LON C. HILL POWER STATION	TX	10/2/2015	Combined Cycle Turbines (>25 MW)	195	MW	oxidation catalyst	2	PPM		0			0		
TX-0773	FGE EAGLE PINES PROJECT	TX	11/4/2015	Combined Cycle Turbines (>25 MW)	321	MW	Oxidation Catalyst	2	PPM		0			0		
TX-0788	NECHES STATION	TX	3/24/2016	Combined Cycle & Cogeneration	231	MW	OXIDATION CATALYST	2	PPM		0			0		
TX-0789	DECORDOVA STEAM ELECTRIC STATION	TX	3/8/2016	Combined Cycle & Cogeneration	231	MW	OXIDATION CATALYST	2	PPM		0			0		
TX-0819	GAINES COUNTY POWER PLANT	TX	4/28/2017	Combined Cycle Turbine with Heat Recovery Steam Generator, fired Duct Burners, and Steam Turbine Generator	426	MW	Oxidation catalyst and good combustion practices	3.5	PPMVD	15% O2	0			0		

TX-0834	MONTGOMERY COUNTY POWER STATIOIN	TX	3/30/2018	Combined Cycle Turbine	2635	MMBTU/HR/UNIT	Oxidation catalyst	2	PPMVD	15% O2 3 HOUR AVERAGE	0			0		
VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	COMBUSTION TURBINE GENERATOR WITH DUCT-FIRED HEAT RECOVERY STEAM GENERATORS (3)	3227	MMBTU/HR	Oxidation Catalyst and good combustion practices	1.4	PPMVD		214.8	T/YR	PER TURBINE-12 MO ROLLING TOTAL	0		
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Natural-Gas-Fired Combined-Cycle Turbine (P01)	4671	MMBTU/H	Oxidation Catalyst, good combustion control	2.7	PPM AT 15% O2	168-HR AVG., NAT. GAS, DUCT FIRING	0.6	PPM AT 15% O2	168-HR AVG., NAT. GAS, W/O DUCT FIRING	0		
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Combined Cycle Turbine/Duct Burner	2419.61	mmBtu/Hr	Oxidation Catalyst & Good Combustion Practices	5.3	LB/H		0.0022	LB/MMBTU		2	PPM	@ 15% O2
*WV-0033	MAIDSVILLE	WV	1/5/2022	Combustion Turbine & Duct Burner (CT-01/HRSG1 & CT-02/HRSG2)	1275	mw	good combustion practices and oxidation catalyst	1	PPMDV @ 15% O2	AVG OF 3 1-HR TEST RUNS (W/O DUCT FIRING	2	PPMDV @ 15% O2	AVG OF 3 1-HR TEST RUNS (W DUCT FIRING	11.19	LB/HR	AVG OF 3 1-HR TEST RUNS
*WV-0033	MAIDSVILLE	WV	1/5/2022	Combustion Turbine & Duct Burner (CT-01/HRSG1 & CT-02/HRSG2)	1275	mw	good combustion practices and oxidation catalyst	1	PPMDV @ 15% O2	AVG OF 3 1-HR TEST RUNS (W/O DUCT FIRING	2	PPMDV @ 15% O2	AVG OF 3 1-HR TEST RUNS (W DUCT FIRING	11.89	LB/HR	AVG OF 3 1-HR TEST RUNS
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Combined Cycle Turbine (EP01)	40	MW	Oxidation Catalyst	3	PPMV AT 15% O2	1-HOUR	3	LB/H	3-HOUR AVERAGE	14.7	T/YR	
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Combined Cycle Turbine (EP02)	40	MW	Oxidation Catalyst	3	PPMV AT 15% O2	3-HOUR AVERAGE	3	LB/H	3-HOUR AVERAGE	14.7	T/YR	

ATTACHMENT E:

Reasonably Available Control Measure Analysis

VOC AND NO_X
REASONABLY AVAILABLE CONTROL MEASURES (RACM) ANALYSIS
FOR
HYDROGRAPHIC AREA (HA) 212

togetherforbetter

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1.0 INTRODUCTION

Section 172(c)(1) of the Clean Air Act requires states to implement reasonably available control measures ("RACM") to assure that a nonattainment area attains the NAAQS as expeditiously as practicable. Specifically, the Act states:

> [i]n general – Such plan provisions shall provide for the implementation of all reasonably available control measures as expeditiously as practicable (including such reductions in emissions from existing sources in the area as may be obtained through the adoption, at a minimum, of reasonably available control technology) and shall provide for attainment of the national primary ambient air quality standards [42 U.S.C. § 7502(c)(1)].

EPA has not identified a specific set of control measures that qualify as RACM: "Under EPA's policy concerning RACM there are no measures that are automatically deemed RACM" (70 FR 71660). Instead, EPA recognizes that the requirement for RACM relates to the requirement to achieve attainment of the NAAQS. EPA determined that it may approve any SIP submittal lacking specific RACM control measures if the state demonstrates "(a) that reasonable further progress and attainment of the NAAQS are assured, and (b) that application of all RACM would not result in attainment any faster..." (44 FR 20372, 20375). Several courts have upheld EPA's interpretation of the RACM requirement (e.g., *Sierra Club v. EPA*, 314 F. 3d 735 (5th Cir. 2002) and *Sierra Club* v. *EPA*, 294 F. 3d 155 (D.C. Cir. 2002)).

2.0 IDENTIFYING RACM CONTROL MEASURES

RACM includes the emissions controls necessary to meet reasonable further progress (RFP) requirements and bring an area into attainment as expeditiously as practicable. Such control measures can include control of point, area, onroad, and/or nonroad emission sources. To qualify as RACM, EPA considers whether the control measure meets five criteria. The control measures should:

- Be technologically feasible;
- Be economically feasible;
- Not result in "substantial widespread and long-term adverse impacts";
- Not be "absurd, unenforceable, or impracticable"; and
- "[A]dvance the attainment date by at least one year" (74 FR 2945, 2951).

In identifying available control measures, state and local air pollution control agencies consider applying control measures emissions sources inside or outside the nonattainment area if emissions reductions from the wider geographic area reduce ozone concentrations within the nonattainment area.

RACM measures can reduce either VOC or NO_x emissions. However, if emissions reductions of one of these pollutants will not contribute to attainment, then available control measures for that pollutant need not be considered in the RACM analysis: "If a state demonstrates that implementation of VOC emissions reduction measures will not contribute to an area's reasonable further progress or to attainment, then additional control of VOC emissions does not need to be further considered for RACM purposes" (80 FR 12264).

Additionally, a state or local air pollution control agency need not consider control measures for emissions sources that will not lead to a decrease in the ambient air concentration of ozone. EPA has determined that where an emissions source contributes "'only negligibly' to ambient concentrations that exceed the NAAQS," applying a control measure to the emissions source is not reasonable (57 FR 13498, 13540).

Finally, in identifying potential control measures, a state and local air pollution control agency should consider "...the time needed to analyze, develop, and implement the measure" (44 FR 20372, 20375). If a control measure is available, but implementation of the measure in the nonattainment area could not occur on a schedule that would achieve or advance the area's attainment date, then "EPA would not consider it reasonable to require implementation of such measures" (57 FR 13498, 13560). To advance the area's attainment date, the measure must provide emissions reductions such that the nonattainment area would achieve attainment one year sooner (e.g., 40 CFR § 51.1004(a)(1)(i)).

3.0 METHODOLOGY FOR RACM ANALYSIS FOR HA 212

The purposes of a RACM analysis are to (1) identify control measures necessary to meet reasonable further progress and attainment by an area's attainment date, and (2) determine whether additional control measures exist that would advance the attainment date by one year. Control measures meeting one of these criterion are considered reasonably available.

3.1 Pollutants Considered

RTP considered both NO_x and VOC emissions reduction control measures for RACM. The attainment modeling shows HA 212 includes a balanced mix of NO_x and VOC sensitive ozone production on the top 10 simulated days at the highest modeled design value monitoring site (Joe Neal). There are also substantial variations in day-to-day sensitivities. This means that, in the near term, ambient air concentrations of ozone should respond to either VOC or NO_x emissions reductions – making reductions in either pollutant a candidate for effective contingency measures (DES, 2024e).

3.2 Control Measures Evaluated

RTP developed a list of potential NO_x control measures using EPA's Menu of Control Measures for NAAQS Implementation (available at: [Menu of Control Measures for NAAQS Implementation | US EPA]), and considered transportation control measures (TCMs) and control measures reviewed in other state RACM plans (EPA, 2022). The Menu of Control Measures provides a broad listing of potential emissions reduction measures for reducing NO_x and VOC emissions. DES also consulted with the Regional Transportation Commission of Southern Nevada to identify potential TCMs that could be applied in the area to reduce mobile source emissions, and provided this information to RTP.

For VOC, most of the control measures listed on EPA's Menu of Control Measures included

VOC RACT CTGs, which RTP already thoroughly evaluated in the CTG Reasonably Available Control Technology Analysis (DES, 2024c). For this reason, RTP conducted no additional evaluation of EPA's Menu of Control Measures for VOC. Instead, RTP identified potential VOC control measures based on SCC with emissions reported in the inventories above a 0.10 tpd VOC threshold.

DES then reviewed state regulations and state RACM analyses to identify potential control measures for these categories, listed in Table 1.

Table 1. Nonpoint Source Categories with Greater than 0.01 tpy VOC Emissions in 2015 Ozone NAAQS SIP Inventory

SCC	SCC Description
2680003000	Waste Disposal, Treatment, and Recovery; Composting; 100% Green Waste (e.g., residential or municipal yard wastes); All Processes
2501012013	Storage and Transport; Petroleum and Petroleum Product Storage; Commercial Portable Gas Cans; Spillage During Transport
2461800000	Solvent Utilization; Miscellaneous Non-industrial: Commercial; Pesticide Application: All Processes; Total: All Solvent Types
2610000500	Waste Disposal, Treatment, and Recovery; Open Burning; All Categories; Land Clearing Debris (use 28-10-005-000 for Logging Debris Burning)
2501011013	Storage and Transport; Petroleum and Petroleum Product Storage; Residential Portable Gas Cans; Spillage During Transport
2501011012	Storage and Transport; Petroleum and Petroleum Product Storage; Residential Portable Gas Cans; Evaporation (includes Diurnal losses)
2501012014	Storage and Transport; Petroleum and Petroleum Product Storage; Commercial Portable Gas Cans; Refilling at the Pump - Vapor Displacement
2501011011	Storage and Transport; Petroleum and Petroleum Product Storage; Residential Portable Gas Cans; Permeation
2302002200	Industrial Processes; Food and Kindred Products: SIC 20; Commercial Cooking - Charbroiling; Under-fired Charbroiling
2501012012	Storage and Transport; Petroleum and Petroleum Product Storage; Commercial Portable Gas Cans; Evaporation (includes Diurnal losses)
2501012011	Storage and Transport; Petroleum and Petroleum Product Storage; Commercial Portable Gas Cans; Permeation

Finally, RTP also reviewed a spreadsheet prepared by Ramboll U.S. Consulting, Inc. for DES, which identifies potential controls and estimates cost effectiveness and emissions reductions for certain control measures, and used this information in preparing the RACM analysis (Ramboll, undated).

In Section 5.0, Tables 2 and 3 identify potential onroad and offroad TCMs, while Table 4 identifies potential control measures for NOx and Table 5 identifies potential VOC control measures.

3.3 Estimating Emissions Reductions and Cost Effectiveness

After identifying potential control measures, RTP considered the degree of emissions reductions that could result from implementing the control. RTP used the 1997 ozone NAAQS second maintenance plan 2023 emissions inventory (DES, 2021) to estimate emissions reductions for point sources, and the 2023 estimates in the 2015 Ozone NAAQS SIP Inventory (DES, 2024a) for nonpoint sources and other categories. (The full 2015 Ozone NAAQS SIP Inventory was not yet available at the time of the analysis).

If the emission inventories included emissions that might be controlled by a potential measure, then RTP presumed the measure is technically feasible for purposes of this RACM evaluation. If estimated cost effectiveness for an available control measure is less than $5,500/ton, then RTP considered the measure potentially cost effective. RTP did not consider whether some or all the emissions in the inventory are already meeting some level of emissions control and assumed no existing control. Also, there are multiple available control options for some source categories; RTP generated the emissions reduction estimates assuming no overlap in the available emissions controls. If emissions, in fact, are already controlled, then this impacts the cost effectiveness conclusions.

In identifying potential emission reductions from the inventories, RTP eliminated individual point sources reporting less than 0.003 tpd NO_x or 0.10 tpd VOC. These source emissions are negligible sources of emissions and unlikely to be cost effective to control. After grouping individual point or nonpoint sources together, RTP also eliminated groupings collectively reporting less than 0.10 tpd of NO_x or VOC, because these emissions are also negligible and unlikely to be cost effective to control (MDE, undated).

The only point source categories meeting the VOC threshold are SCC 20200102 (generators), and SCC 50410312 (thermal oxidizers). The generators will be subject to major source VOC CTG RACT requirements and RTP determined that no additional controls measures are cost effective in the major source RACT analyses (DES, 2024d). Thermal oxidizers are a VOC emissions control measure, and therefore, no additional control measure is appropriate for this type of VOC emissions unit. For nonpoint source emissions, DES identified several SCC codes that met the VOC threshold, that also were not otherwise regulated by a RACT requirement. These categories are listed in Table 1 in Section 3.2.

To estimate emissions reductions from identified control measures, RTP assigned 2023 summer day NO_x emissions by source classification code (SCC) to potential control measures for that emissions type. In some cases, RTP grouped similar equipment from different SCC together and assigned those emissions to a single control option. RTP used control efficiency provided in by EPA to estimate emissions reductions for a control measure (EPA, 2022), when available, in some cases, relied on previous estimates provided by Ramboll US Consulting Inc (Ramboll, undated), and in others researched methods for computing cost and emissions reductions.

When RTP could estimate potential emissions reductions, the “RACM Conclusions” column includes this estimate. If a control measure is associated with emissions sources that RTP determined were negligible, then DES determined that an emissions control measure is not cost effective irrespective of the stated cost-per-ton (cost effectiveness) reported for the control measure.

4.0 RACM ANALYSIS FINDINGS

DES cannot implement any potential control measure identified in Section 5.0, Tables 2-5 in time to advance the attainment date by one year. EPA requires that ozone control measures be implemented, and attainment be modeled, for the last full ozone season preceding the attainment date. The attainment date for HA 212 is August 3, 2024. Ozone attainment by this date will be determined using a 3-year average of the annual fourth-highest daily maximum ozone concentrations. For the August 3, 2024 attainment date, this 3-year period was 2021–2023. To advance the attainment date by a year (to August 3, 2023), EPA would rely on the 3-year average of the annual fourth-highest daily maximum ozone concentrations for the years 2020–2022. Accordingly, for measures to advance attainment to 2023, DES would have had to adopt control measures and have these measures in effect no later than December 31, 2022. This date occurred before EPA reclassified HA 212 to moderate nonattainment.

In addition, sensitivity modeling conducted to support an interprecursor trading ratio showed that, in the near term, although both precursor have some effect on ozone ambient air concentrations, VOC emissions are more effective in reducing the concentration in HA 212 than NO_x reductions (DES, 2024e). The source apportionment modeling study further suggests that external, uncontrollable factors significantly impact ambient ozone concentrations in HA 212, including natural emissions (i.e., biogenic, lightning, oceanic sources), international transport, and transport of anthropogenic emissions from upwind California monitoring sites located over the Mojave Desert, and that imposition of local control measures will have a negligible effect on HA 212's ozone design value concentration and ability to reach attainment. Specifically, the attainment modeling showed that a 15.13 tpd VOC emissions reduction from local control measures would only reduce HA-212's design value concentration by only 0.02 ppb (DES, 2024d). RTP did not identify additional local control measures that would produce this amount of tpd VOC emissions reduction, and even if such control measures were identified and implemented in the near term, the 0.02 ppb change in ozone ambient air concentrations would not be sufficient for HA 212 to reach attainment.

In summary, RTP identified no additional control measures that could advance the attainment date by at least one year. Even if such control measures existed, it is also not feasible to implement the control measures to advance the attainment date by at least one year, because such measure could not be adopted and put into effect before December 31, 2022. Therefore, there are no control measures that satisfy the RACM criteria. RTP recommends that DES continue to evaluate the technical and economic feasibility of these control measures for other purposes (e.g., contingency measures).

5.0 RACM CONCLUSIONS FOR POTENTIAL RACM CONTROL MEASURES

Table 2. Potential Transportation Control Measures for NO_X and VOC Emissions Reductions

Sector	Control Measure	Cost Effectiveness ($/ton)	RACM Conclusion
Gasoline-Passenger Vehicles	Reformulated Gasoline Passenger Vehicles	$3,613	This measure might reduce NOx by 0.58 tpd and VOC by 1.52 tpd. There are supply chain issues that raise the technical feasibility of implementing this control measure. This measure is not necessary for attainment and cannot advance the moderate area attainment date.
Diesel - Heavy Duty Haul Trucks	Fuel Composition Requirements	$50,000	This measure might reduce NOx by 0.07 tpd, but is not cost effective. The measure is not necessary for attainment and cannot advance the moderate area attainment date.
Light Duty Gasoline and Diesel Vehicles	Zero Emissions Vehicle Incentive Program	$17,000-$340,000	NDEP has already adopted this measure.
Heavy Duty Gasoline and Diesel Vehicles and Buses	Accelerate Fleet Turnover/Retrofit Requirements	$3,822	The measure might reduce NOx by 0.22 tpd. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Gasoline Vehicles	Petition EPA to remove 1 PSI Allowance for 9-10% Ethanol Blends	unknown	This measure might reduce VOC emissions by 0.49 tpd. This measure is not necessary for attainment and cannot advance the moderate area attainment date.
Gasoline Vehicles	Low RVP Fuel	$5700/ton	This measure might reduce VOC emissions by 0.004 tpd; but this control measure is not cost effective. This measure is not necessary for attainment and cannot advance the moderate area attainment date.
Heavy Duty Haul Trucks - Diesel	Reduce Idling	$15,751	This measure might reduce NOx emissions by 0.162 tpd and VOC emissions by 0.018 tpd. This control measure is not cost effective; is not necessary for attainment and cannot advance the moderate area attainment date.
Heavy Duty Haul Trucks - Diesel	Aerodynamic Tires and Devises; or low rolling resistance tires and retread tire technologies	$17,000	This measure might reduce NOx emissions by 0.002 to 0.20 tpd; this measure is not cost effective; is not necessary for attainment and cannot advance the moderate area attainment date.
Refuse Collection Trucks	Alternative Fuels	$25,000	This measure might reduce NOx emissions by 0.02 tpd; this measure is not cost effective; is not necessary for attainment and cannot advance the moderate area attainment date.

Sector	Control Measure	Cost Effectiveness ($/ton)	RACM Conclusion
Heavy Duty Haul Trucks - Diesel	Truck Stop Electrification	$10,000-$15,000 per parking space for standalone system; $2500 per parking space for shore power system; $4000 per truck (Centralina, 2007)	This control measure might reduce VOC emissions by 0.0004 tpd VOC and NOx emissions 0.003 tpd emissions reductions per truck parking spot. With an average truck stop having 145 parking spots and 23 hours of use, this control measure could result in 0.05 tpd VOC and 0.42 tpd NOx per truck stop. The economic feasibility of this control measure is not known. Implementation would take at least 1 year. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Heavy Duty Haul Trucks - Diesel	Ultra-low NOx Engine Replacement	Unknown	This measure might reduce NOx emissions by 0.68 tpd. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Diesel School Buses	Idle Reduction	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Diesel School Buses	Electrification	>$30,000	This measure might reduce NOx emissions by 0.16 tpd/per bus. This measure costs $400,000 per school bus. (EPA, 2024) Costs may be offset by grants but it is likely that the measure remains not cost effective. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Commuters	New or Expanded Mobility Services	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Commuters	Education and Outreach	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Gasoline and Diesel Onroad Vehicles	Traffic Signal Optimization	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Diesel Buses	Conversion of Public Transit Fleet Cleaner Fuels	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.

Sector	Control Measure	Cost Effectiveness ($/ton)	RACM Conclusion
Commuter	FlexRide On-demand Service	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Gasoline and Diesel Vehicles	Roadway and Congestion Pricing	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Gasoline and Diesel Vehicles	Enhanced I/M	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
`Gasoline and Diesel Vehicles	Auto Technician Training	Unknown	This control measure has already been implemented. Chapter 445B.700-835 of the Nevada Revised Statutes and Nevada Administrative Code includes an auto technician training and certification program.
Gasoline and Diesel Vehicles	Alternative Fuels for Gov't Fleet	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Gasoline Service Stations	Low Permeation Fuel Hoses	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Gasoline Service Stations	Dripless Gasoline Nozzles	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Heavy Duty Haul Trucks - Diesel	Encourage Truck Fleet Efficiencies	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Heavy Duty Haul Trucks - Diesel	Auxiliary Power Units to Reduce Truck Idling	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Diesel Vehicles	Expand use of Biodiesel Fuel	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot

Sector	Control Measure	Cost Effectiveness ($/ton)	RACM Conclusion
			advance the moderate area attainment date.
Gasoline and Diesel Vehicles	Reduce VOC content in Windshield Wiper Fluid – below 35%	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Fleet Buses	Electrify Tour Buses	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Commuters	Free Transit Passes	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Fleet Buses	Dedicated Bus Lanes for Faster Travel	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Commuters	Rail lines from Airport to Strip	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Commuters	Underwrite Vanpool Insurance	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Commuters	Pay As You Go Auto Insurance ($/gallons)	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Commuters	Park and Ride Lots	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Commuters	Bike/Pedestrian Paths and Locker facilities	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.

Sector	Control Measure	Cost Effectiveness ($/ton)	RACM Conclusion
Gasoline and Diesel Vehicles	Shift Rush Hour by 30 minutes	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Gasoline and Diesel Vehicles	Eliminate/Reduce Drive Through Fast Food or Set Service Guidelines to Reduce Idling	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Gasoline and Diesel Vehicles	Reduce Speed Limits	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
All Vehicles	"Cash for Clunkers" Passenger Cars, Taxis and Buses	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Heavy Duty Haul Trucks - Diesel	Diesel Engine Chip Reflash/OTC Measure	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Gasoline Vehicles	Low Income Vehicle Repair Assistance	Unknown	This control measure has already been implemented. The Smog Free Clark County Voucher Program will pay for emissions-related repairs, up to $975, on 1968-1999 model year vehicles based on income eligibility criteria.
Airport	Regulate Disposal of Fuel Samples from Preflight Checks at Airport	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Gasoline Vehicles	Hydrogen Fueled Vehicles	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
All Vehicles	Implement Advanced Highway Incident Management System	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Heavy Duty Haul Trucks - Diesel	Automatic Tire Inflation Systems	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot

Sector	Control Measure	Cost Effectiveness ($/ton)	RACM Conclusion
			advance the moderate area attainment date.
Heavy Duty Haul Trucks - Diesel	Improved Freight Logistics	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Heavy Duty Haul Trucks - Diesel	Low Viscosity Lubricants	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Heavy Duty Haul Trucks - Diesel	Reduce Truck Weight Limits	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Heavy Duty Haul Trucks - Diesel	Truck Cab or Bunk Heaters/AC	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
All Vehicles	Mandate Automatic Engine Stop-Start Controls	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Fleet Vehicles	Transit Fleet Cleaner Fuels	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Commuters	TDM Program Expansion – free transit passes	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
All Vehicles	Enhanced Integration of Land Use and Transportation Planning	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
Commuters	RTC Smart Trips – service to promote alternative transportation	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.

Sector	Control Measure	Cost Effectiveness ($/ton)	RACM Conclusion
Gasoline and Diesel Passenger Cars	Game Day Express – Service to Stadium	Unknown	This measure is technically feasible. The economic feasibility of the measure is unknown. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.

Table 3. Potential Nonroad Source VOC and NOx Emissions Control Measures

Sector	Control Measure	Cost Effectiveness ($/ton)	RACM Conclusion
Off-highway equipment - Gasoline/LPG/CNG	Reformulated Gasoline (RFG)	Unknown	This measure might reduce NOx emissions by 0.87 tpd and VOC emissions by 2.16 tpd. This economic feasibility of this control measure is unknown. This control measure is not necessary for attainment and cannot advance the attainment date.
Off-highway equipment - Diesel	Repowering Engines/Retrofits	$4,500	This measure might reduce NOx emissions by 0.31 tpd and VOC emissions by 0.005 tpd. This control measure is not necessary for attainment and cannot advance the attainment date.
Offroad Engines - Diesel	Tier II Engine Replacement to Tier III or IV	$43, 493	This measure might reduce NOx emissions by 0.110 tpd. This is not cost effective. This control measure is not necessary for attainment and cannot advance the attainment date.
Offroad Construction, Industrial and Airport Equipment	Engine Replacement to Tier IV	$16,000	This measure might reduce NOx emissions by 1.55 tpd. This control measure is not cost effective. This control measure is not necessary for attainment and cannot advance the attainment date.
Off-highway Construction and Agriculture Equipment	Electrification	Unknown	This measure might reduce NOx emissions by 0.151 tpd and VOC emissions by 0.02 tpd. The economic feasibility of this measure is unknown. This control measure is not necessary for attainment and will not advance the attainment date.
Off-highway Construction and Agriculture Equipment	Biodiesel	Unknown	The economic feasibility of this measure is unknown. This control measure is not necessary for attainment and cannot advance the attainment date.

Sector	Control Measure	Cost Effectiveness ($/ton)	RACM Conclusion
Off-highway Construction and Agriculture Equipment	Cap and Trade	Unknown	The economic feasibility of this measure is unknown. This control measure is not necessary for attainment and cannot advance the attainment date.
Small Offroad Engines	Electrification or Low emitting Engines	$16,000	This measure might reduce NOx emissions by 0.015 tpd and VOC emissions by 0.153 tpd. The measure is not cost effective. This control measure is not necessary for attainment and cannot advance the attainment date.
Locomotives	Upgrade Engines in Switcher Locomotives - Diesel-Electric Hybrid Locomotives	$12, 250	This measure is not cost effective; is not needed for attainment; and will not advance the moderate area attainment date.

Table 4. Analysis of Potential Point and Nonpoint Source NO_X Control Measures for Clark County

SCC	Sector	Source Category	Emission Reduction Measure	Control Efficiency (%)	Cost Effectiveness (2018$/ton reduced)	RACM Conclusion
	NonEGU Point	Adipic Acid Manufacturing	Extended Absorption	86	$156	No sources operating in Clark County.
	NonEGU Point	Adipic Acid Manufacturing	Thermal Reduction	81	$728	No sources operating in Clark County.
	NonEGU Point	Ammonia - NG-Fired Reformers	Low NOx Burner and Flue Gas Recirculation	60	NOX < 365 tpy: $4,440 NOX > 365 tpy: $1,023	No sources operating in Clark County.
	NonEGU Point	Ammonia - NG-Fired Reformers	Low NOx Burner	50	NOX < 365 tpy: $1,422 NOX > 365 tpy: $937	No sources operating in Clark County.
	NonEGU Point	Ammonia - NG-Fired Reformers	Selective Catalytic Reduction	90	$3,421	No sources operating in Clark County.
	NonEGU Point	Ammonia - NG-Fired Reformers	Selective Non-Catalytic Reduction	50	NOX < 365 tpy: $6,711 NOX > 365 tpy: $2,723	No sources operating in Clark County.
	NonEGU Point	Ammonia - Oil-Fired Reformers	Low NOx Burner and Flue Gas Recirculation	60	NOX < 365 tpy: $1,942 NOX > 365 tpy: $676	No sources operating in Clark County.
	NonEGU Point	Ammonia - Oil-Fired Reformers	Low NOx Burner	50	NOX < 365 tpy: $694 NOX > 365 tpy: $746	No sources operating in Clark County.
	NonEGU Point	Ammonia - Oil-Fired Reformers	Selective Catalytic Reduction	80	NOX < 365 tpy: $2,567 NOX > 365 tpy: $1,405	No sources operating in Clark County.

SCC	Sector	Source Category	Emission Reduction Measure	Control Efficiency (%)	Cost Effectiveness (2018$/ton reduced)	RACM Conclusion
	NonEGU Point	Ammonia - Oil-Fired Reformers	Selective Non-Catalytic Reduction	50	NOX < 365 tpy: $4,474 NOX > 365 tpy: $1,821	No sources operating in Clark County.
	NonEGU Point	Ammonia Prod; Feedstock Desulfurization	Low NOx Burner and Flue Gas Recirculation	60	NOX < 365 tpy: $4,440 NOX > 365 tpy: $1,023	No sources operating in Clark County.
30500205, 30500206	NonEGU Point	Asphaltic Conc; Rotary Dryer; Conv Plant	Low NOx Burner	50	NOX < 365 tpy: $3,815 NOX > 365 tpy: $3,122	Emissions from this source category are negligible and therefore the control measure is not cost effective. This measure is not necessary for attainment and cannot advance the moderate area attainment date.
	NonEGU Point	By-Product Coke Mfg; Oven Underfiring	Selective Non-Catalytic Reduction	60	$2,844	No sources operating in Clark County.
30500606, 30500620, 30500622	NonEGU Point	Cement Manufacturing - Dry	Selective Catalytic Reduction	90	$6,703	No sources operating in Clark County.
	NonEGU Point	Cement Manufacturing - Dry	Selective Non-Catalytic Reduction - Ammonia	50	$1,474	No sources operating in Clark County.
	NonEGU Point	Cement Manufacturing - Dry	Selective Non-Catalytic Reduction	50	$1,335	No sources operating in Clark County.
	NonEGU Point	Cement Manufacturing - Dry2	Selective Catalytic Reduction	85	$5,844	No sources operating in Clark County.
30500606	NonEGU Point	Cement Manufacturing - Wet	Selective Catalytic Reduction	90	$5,728	No sources operating in Clark County.
	NonEGU Point	Cement Manufacturing - Wet	Selective Non-Catalytic Reduction	50	$1,335	No sources operating in Clark County.
	NonEGU Point	Cement Manufacturing - Wet or Dry	Low NOx Burner	27	$653	No sources operating in Clark County.

SCC	Sector	Source Category	Emission Reduction Measure	Control Efficiency (%)	Cost Effectiveness (2018$/ton reduced)	RACM Conclusion
	NonEGU Point	Cement Manufacturing - Wet or Dry	Mid-Kiln Firing	41	$82	No sources operating in Clark County.
	NonEGU Point	Ceramic Clay Mfg; Drying	Low NOx Burner	50	NOX < 365 tpy: $3,815 NOX > 365 tpy: $3,122	No sources operating in Clark County.
	NonEGU Point	Coal Cleaning-Thrml Dryer; Fluidized Bed	Low NOx Burner	50	NOX < 365 tpy: $1,338 NOX > 365 tpy: $268	No sources operating in Clark County.
30190013	NonEGU Point	Comm./Inst. Incinerators	Selective Non-Catalytic Reduction	45	$1,960	Emissions from this source category are negligible and therefore the control measure is not cost effective. This measure is not necessary for attainment and cannot advance the moderate area attainment date.
	NonEGU Point	Conv Coating of Prod; Acid Cleaning Bath	Low NOx Burner	50	NOX < 365 tpy: $3,815 NOX > 365 tpy: $3,122	No sources operating in Clark County.
	NonEGU Point	External Combustion Boilers, Elec Gen, Coal	Selective Non-Catalytic Reduction	40	$1,642	No sources operating in Clark County.
20100201	NonEGU Point	External Combustion Boilers, Elec Gen, Dis Oil	Selective Non-Catalytic Reduction	50	$5,838	This control measure could result in emissions reductions of 1.4 tpd. This control measure is not cost effective. This control measure is not needed for attainment and cannot advance the moderate area attainment date.
10100601, 10100602	NonEGU Point	External Combustion Boilers, Elec Gen, Nat Gas	Natural Gas Reburn	50	$2,821	Emissions from this source category are negligible and therefore the control measure is not cost effective. This measure is not necessary for attainment and cannot advance the moderate area attainment date.

SCC	Sector	Source Category	Emission Reduction Measure	Control Efficiency (%)	Cost Effectiveness (2018$/ton reduced)	RACM Conclusion
	NonEGU Point	External Combustion Boilers, Elec Gen, Res Oil and Solid Waste	Selective Non-Catalytic Reduction	50	$3,231	No sources operating in Clark County.
	NonEGU Point	Fbrglass Mfg; Txtle-Type Fbr; Recup Furn	Low NOx Burner	40	$2,931	No sources operating in Clark County.
	NonEGU Point	Fluid Cat Cracking Units; Cracking Unit	Selective Catalytic Reduction	90	$8,269	No sources operating in Clark County.
	NonEGU Point	Fluid Cat Cracking Units; Cracking Unit	Low NOx Burner and Flue Gas Recirculation	55	NOX < 365 tpy: $5,532 NOX > 365 tpy: $4,284	No sources operating in Clark County.
	NonEGU Point	Fuel Fired Equip; Furnaces; Natural Gas	Low NOx Burner	50	$989	No sources operating in Clark County.
	NonEGU Point	Fuel Fired Equip; Process Htrs; Pro Gas	Low NOx Burner and Flue Gas Recirculation	55	NOX < 365 tpy: $5,532 NOX > 365 tpy: $4,284	No sources operating in Clark County.
20100801, 31000203, 20300203	NonEGU Point	Gas Turbines - Natural Gas	Catalytic Combustion	98	NOX < 365 tpy: $1,330 DC < 26 MW: $969 DC > 26 MW: $535	This control measure could achieve 0.42 tpd in emissions reductions. This control measure is not necessary for attainment and cannot advance the attainment date.
20100801,	NonEGU Point	Gas Turbines - Natural Gas	Dry Low NOx Combustion	84	NOX < 365 tpy: $434 NOX > 365 tpy: $188	This control measure could achieve 0.36 tpd in emissions reductions. This control measure is not necessary for attainment and cannot advance the attainment date.
31000203,	NonEGU Point	Gas Turbines - Natural Gas	EMx and Dry Low NOx Combustion	99	NOX > 365 tpy: $2,401	Emissions from this source category are negligible. The control measure is not cost effective. This measure is not necessary for attainment and cannot advance the moderate area attainment date.

SCC	Sector	Source Category	Emission Reduction Measure	Control Efficiency (%)	Cost Effectiveness (2018$/ton reduced)	RACM Conclusion
20300203	NonEGU Point	Gas Turbines - Natural Gas	EMx	95	NOX > 365 tpy: $2,401	Emissions from this source category are negligible. The control measure is not cost effective. This measure is not necessary for attainment and cannot advance the moderate area attainment date.
	NonEGU Point	Gas Turbines - Natural Gas	EMx and Water Injection	99	NOX > 365 tpy: $3,467	Emissions from this source category are negligible. The control measure is not cost effective. This measure is not necessary for attainment and cannot advance the moderate area attainment date.
	NonEGU Point	Gas Turbines - Natural Gas	Low NOx Burner	84	NOX < 365 tpy: $850 NOX > 365 tpy: $173	Emissions from this source category are negligible. The control measure is not cost effective. This measure is not necessary for attainment and cannot advance the moderate area attainment date.
20100801, 31000203, 20300203	NonEGU Point	Gas Turbines - Natural Gas	SCR + DLN Combustion	94.6	DC > 26 MW: $564 DC < 26 MW: $2,603 DC < 26 MW: $1,431	This control measure could achieve 0.41 tpd in emissions reductions. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
20100801, 31000203, 20300203	NonEGU Point	Gas Turbines - Natural Gas	Selective Catalytic Reduction and Steam Injection	95	DC > 26 MW: $824 DC < 26 MW: $3,716 DC < 26 MW: $1,995	This control measure could achieve 0.41 tpd in emissions reductions. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
20100801, 31000203, 20300203	NonEGU Point	Gas Turbines - Natural Gas	Selective Catalytic Reduction and Water Injection	94.1	DC > 26 MW: $1,547 DC < 26 MW: $4,034 DC < 26 MW: $1,981	This control measure could achieve 0.41 tpd in emissions reductions. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.

SCC	Sector	Source Category	Emission Reduction Measure	Control Efficiency (%)	Cost Effectiveness (2018$/ton reduced)	RACM Conclusion
20100801, 31000203, 20300203	NonEGU Point	Gas Turbines - Natural Gas	Steam Injection	80	DC > 26 MW: $723 DC < 26 MW: $2,443 DC < 26 MW: $1,186	This control measure could achieve 0.35 tpd in emissions reductions. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
20100801, 31000203, 2030023	NonEGU Point	Gas Turbines - Natural Gas	Water Injection	72	DC > 34.4 MW: $1,055 DC < 34.4 MW: $2,588 DC < 34.4 MW: $1,446	This control measure could achieve 0.32 tpd in emissions reductions. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
	NonEGU Point	Glass Manufacturing - Container	Low NOx Burner	40	$1,436	No sources operating in Clark County.
	NonEGU Point	Glass Manufacturing - Container	Selective Catalytic Reduction	75	$2,135	No sources operating in Clark County.
	NonEGU Point	Glass Manufacturing - Container or Pressed	Cullet Preheat	5	$6,812	No sources operating in Clark County.
	NonEGU Point	Glass Manufacturing - Flat	Catalytic Ceramic Filter	80	$11,414	No sources operating in Clark County.
	NonEGU Point	Glass Manufacturing - Flat	Low NOx Burner	40	$573	No sources operating in Clark County.
	NonEGU Point	Glass Manufacturing - Flat	Selective Catalytic Reduction	75	$1,055	No sources operating in Clark County.
	NonEGU Point	Glass Manufacturing - General	Electric Boost	30	$9,673	No sources operating in Clark County.
	NonEGU Point	Glass Manufacturing - General	Oxygen Enriched Air Staging	65	$797	No sources operating in Clark County.

SCC	Sector	Source Category	Emission Reduction Measure	Control Efficiency (%)	Cost Effectiveness (2018$/ton reduced)	RACM Conclusion
	NonEGU Point	Glass Manufacturing - Pressed	Low NOx Burner	40	$2,601	No sources operating in Clark County.
	NonEGU Point	Glass Manufacturing - Pressed	Selective Catalytic Reduction	75	$4,388	No sources operating in Clark County.
2103007000, 2102007000	NonEGU Point	IC Engines - Gas/ Diesel/ LPG	Ignition Retard	25	NOX < 365 tpy: $1,335 NOX > 365 tpy: $850	Some of these engines may already be meeting EPA emissions control requirements. If all emissions from the SCC are uncontrolled and meet the source category description, then maximum emissions reductions of <0.03 tpd could result from implementing this control. This measure is not necessary for attainment and cannot advance the moderate area attainment date.
20200102	NonEGU Point	IC Engines - Gas/ Diesel/ LPG	Ignition Retard	25	NOX < 365 tpy: $1,335 NOX > 365 tpy: $850	This control measure could result in 0.18 tpy emissions reductions for units emitting above 0.003 tpd. This measure is not cost effective. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
20100102, 20300101	NonEGU Point	ICE - Diesel	Selective Catalytic Reduction	90	NOX < 365 tpy: $11,747	This control measure is not cost effective.
	NonEGU Point	ICI Boilers - Coal	Selective Catalytic Reduction	90	$8,194	No sources operating in Clark County.
	NonEGU Point	ICI Boilers - Coal	Selective Non-Catalytic Reduction	35	$8,410	No sources operating in Clark County.
	NonEGU Point	ICI Boilers - Coal/Wall	Low NOx Burner	47.5	25tpy < NOX < 100 tpy: $8,057 100tpy < NOX < 250 tpy: $2,694 NOX > 250 tpy: $909	No sources operating in Clark County.

SCC	Sector	Source Category	Emission Reduction Measure	Control Efficiency (%)	Cost Effectiveness (2018$/ton reduced)	RACM Conclusion
	NonEGU Point	ICI Boilers - Coal/Wall	Ultra Low NOx Burner and Selective Catalytic Reduction	91	25tpy < NOX < 100 tpy: $17,697 100tpy < NOX < 250 tpy: $6,312 NOX > 250 tpy: $2,343	No sources operating in Clark County.
	NonEGU Point	ICI Boilers - Coal/Wall	Ultra Low NOx Burner and Selective Non-Catalytic Reduction	69.5	25tpy < NOX < 100 tpy: $12,875 100tpy < NOX < 250 tpy: $4,877 NOX > 250 tpy: $2,143	No sources operating in Clark County.
10300602, 20200202	NonEGU Point	ICI Boilers - Gas	Flue Gas Recirculation	40	25tpy < NOX < 50 tpy: $23,290 50tpy < NOX < 100 tpy: $12,423 NOX > 100 tpy: $6,602	There are no sources emitting above 25 tpy in the emissions inventory. Therefore, this control measure is not cost effective. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
10300602, 20200202	NonEGU Point	ICI Boilers - Gas	Low NOx Burner and Flue Gas Recirculation	61	25tpy < NOX < 50 tpy: $25,768 50tpy < NOX < 100 tpy: $13,798 NOX > 100 tpy: $7,338	There are no sources emitting above 25 tpy in the emissions inventory. Therefore, this control measure is not cost effective. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
10300602, 20200202	NonEGU Point	ICI Boilers - Gas	Ultra Low NOx Burner	75	25tpy < NOX < 50 tpy: $8,605 50tpy < NOX < 100 tpy: $4,603 NOX > 100 tpy: $2,451	There are no sources emitting above 25 tpy in the emissions inventory. Therefore, this control measure is not cost effective. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.

SCC	Sector	Source Category	Emission Reduction Measure	Control Efficiency (%)	Cost Effectiveness (2018$/ton reduced)	RACM Conclusion
10300602, 20200202	NonEGU Point	ICI Boilers - Gas	Ultra Low NOx Burner and Selective Catalytic Reduction	91	25tpy < NOX < 50 tpy: $31,198 50tpy < NOX < 100 tpy: $17,166 NOX > 100 tpy: $9,300	There are no sources emitting above 25 tpy in the emissions inventory. Therefore, this control measure is not cost effective. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
10100602, 10201402, 5010799, 10200603	NonEGU Point	ICI Boilers - Gas	Low NOx Burner and Selective Non-Catalytic Reduction	69.5	25tpy < NOX < 50 tpy: $21,826 50tpy < NOX < 100 tpy: $12,047 NOX > 100 tpy: $6,740	The only stationary source in the source category emitting above 25tpy will be regulated by major source NOx RACT. No additional emissions control is cost effective.
10100602, 10201402, 5010799, 10200603	NonEGU Point	ICI Boilers - Gas	Selective Catalytic Reduction	90	$11,441	This control is not cost effective. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
10300602	NonEGU Point	ICI Boilers - Gas	Selective Non-Catalytic Reduction	35	$11,071	The control measure is not cost effective. If the control measure is applied to sources in the county emitting greater than 10 tpy, then 0.03 tpd of emissions reductions could be achieved. This measure is not necessary for attainment and cannot advance the moderate area attainment date.
	NonEGU Point	ICI Boilers - Oil	Flue Gas Recirculation	40	NOX > 25 tpy: $13,000	No sources operating in Clark County.
2102004001	NonEGU Point	ICI Boilers - Oil	Low NOx Burner and Flue Gas Recirculation	61	NOX > 25 tpy: $14,054	Emissions in the inventory are from nonpoint sources. Control of emissions are not cost effective.
	NonEGU Point	ICI Boilers - Oil	Low NOx Burner	47.5	NOX > 25 tpy: $1,499	No sources operating in Clark County.

SCC	Sector	Source Category	Emission Reduction Measure	Control Efficiency (%)	Cost Effectiveness (2018$/ton reduced)	RACM Conclusion
20300101	NonEGU Point	ICI Boilers - Oil	Ultra Low NOx Burner and Selective Catalytic Reduction	91	NOX > 25 tpy: $4,076	If this control technology is applied to source emitting above 25 tpy, then it could result in 0.08 tpd of emissions reductions. This measure is not necessary for attainment and cannot advance the moderate area attainment date.
	NonEGU Point	ICI Boilers - Oil	Low NOx Burner and Selective Non-Catalytic Reduction	69.5	NOX > 25 tpy: $3,361	If this control technology is applied to source emitting above 25 tpy, then it could result in 0.17 tpd of emissions reductions. This measure is not necessary for attainment and cannot advance the moderate area attainment date.
10300502	NonEGU Point	ICI Boilers - Oil	Selective Catalytic Reduction	90	$8,914	Emissions from this source category are negligible. The control measure is not cost effective. This measure is not necessary for attainment and cannot advance the moderate area attainment date.
	NonEGU Point	ICI Boilers - Oil	Selective Non-Catalytic Reduction	35	$9,537	
	NonPoint	Industrial Coal Combustion	RACT to 25 tpy (Low NOx Burner)	21	NOX > 25 tpy: $2,341	No sources operating in Clark County.
	NonPoint	Industrial Coal Combustion	RACT to 50 tpy (Low NOx Burner)	21	NOX > 50 tpy: $2,341	No sources operating in Clark County.
	NonEGU Point	Industrial Incinerators	Selective Catalytic Reduction	90	$4,495	Emissions from this source category are negligible and therefore the control measure is not cost effective. This measure is not necessary for attainment and cannot advance the moderate area attainment date.
	NonEGU Point	Industrial Incinerators, Municipal Waste Combustors	Selective Non-Catalytic Reduction	45	$1,960	No sources operating in Clark County.

SCC	Sector	Source Category	Emission Reduction Measure	Control Efficiency (%)	Cost Effectiveness (2018$/ton reduced)	RACM Conclusion
	NonPoint	Industrial NG Combustion	RACT to 25 tpy (Low NOx Burner)	31	NOX > 25 tpy: $1,335	Sources already considered in major source NOx RACT analyses.
	NonPoint	Industrial NG Combustion	RACT to 50 tpy (Low NOx Burner)	31	NOX > 50 tpy: $1,335	Sources already considered in major source NOx RACT analyses.
	NonEGU Point	Industrial NG ICE, 4cycle (rich)	Non-Selective Catalytic Reduction	90	$610	No sources operating in Clark County.
10201402 10200602 50100799 10200603	NonEGU Point	Industrial NG ICE, SCCs with technology not specified	Non-Selective Catalytic Reduction or Adjust Air Fuel Ratio and Ignition Retard	39	NOX < 365 tpy: $2,219 NOX > 365 tpy: $772	If all emissions from the referenced SCCs are uncontrolled and meet the source category description, then maximum emissions reductions of <0.02 tpd could result from implementing this control. This measure is not necessary for attainment and cannot advance the moderate area attainment date.
	NonEGU Point	Industrial NG ICE, SCCs with technology not specified	Non-Selective Catalytic Reduction or Layered Combustion	95.95	$4,924	No sources operating in Clark County.
	NonEGU Point	Industrial NG ICE, SCCs with technology not specified	Non-Selective Catalytic Reduction or Low Emission Combustion	87.45	$667	No sources operating in Clark County.
	NonPoint	Industrial Oil Combustion	RACT to 25 tpy (Low NOx Burner)	36	NOX > 25 tpy: $2,046	Sources already considered in major source NOx RACT analyses.
	NonPoint	Industrial Oil Combustion	RACT to 50 tpy (Low NOx Burner)	36	NOX > 50 tpy: $2,046	Sources already considered in major source NOx RACT analyses.
	NonEGU Point	In-Proc;Process Gas;Coke Oven/Blast Furn	Low NOx Burner and Flue Gas Recirculation	55	NOX < 365 tpy: $5,532 NOX > 365 tpy: $4,284	No sources operating in Clark County.

SCC	Sector	Source Category	Emission Reduction Measure	Control Efficiency (%)	Cost Effectiveness (2018$/ton reduced)	RACM Conclusion
	NonEGU Point	In-Process Fuel Use - Gas	Selective Catalytic Reduction	90	$7,161	No sources operating in Clark County.
	NonEGU Point	In-Process Fuel Use; Natural Gas; Gen	Low NOx Burner	50	NOX < 365 tpy: $3,815 NOX > 365 tpy: $3,122	No sources operating in Clark County.
	NonEGU Point	In-Process Fuel Use; Residual Oil; Gen	Selective Catalytic Reduction	90	$6,446	No sources operating in Clark County.
	NonEGU Point	In-Process Fuel Use; Residual Oil; Gen	Low NOx Burner	37	NOX < 365 tpy: $4,370 NOX > 365 tpy: $1,231	No sources operating in Clark County.
	NonEGU Point	In-Process Fuel Use;Bituminous Coal; Gen	Selective Catalytic Reduction	90	$4,377	No sources operating in Clark County.
	NonEGU Point	In-Process Fuel Use;Bituminous Coal; Gen	Selective Non-Catalytic Reduction	40	NOX < 365 tpy: $2,185 NOX > 365 tpy: $1,630	No sources operating in Clark County.
30501604	NonEGU Point	In-Process; Bituminous Coal; Cement and Lime Kilns	Selective Catalytic Reduction	90	$3,064	Implementation of this control measure on lime kilns emitting greater than 100 tpy could result in 2.16 tpd of emissions reductions if the lime kilns are currently uncontrolled. This measure is not necessary for attainment and cannot advance the moderate area attainment date.
	NonEGU Point	In-Process; Bituminous Coal; Cement Kiln	Selective Non-Catalytic Reduction	50	$1,335	No sources operating in Clark County.
	NonEGU Point	In-Process; Bituminous Coal; Lime Kiln	Selective Non-Catalytic Reduction	50	$1,335	No sources operating in Clark County.

SCC	Sector	Source Category	Emission Reduction Measure	Control Efficiency (%)	Cost Effectiveness (2018$/ton reduced)	RACM Conclusion
	NonEGU Point	In-Process; Process Gas; Coke Oven Gas	Selective Catalytic Reduction	90	$9,212	No sources operating in Clark County.
	NonEGU Point	In-Process; Process Gas; Coke Oven Gas	Low NOx Burner	50	NOX < 365 tpy: $3,815 NOX > 365 tpy: $3,122	No sources operating in Clark County.
	NonEGU Point	Internal Combustion Engines - Gas	Adjust Air to Fuel Ratio	20	NOX < 365 tpy: $2,723 NOX > 365 tpy: $659	No sources operating in Clark County.
	NonEGU Point	Internal Combustion Engines - Gas	Adjust Air to Fuel Ratio and Ignition Retard	30	NOX < 365 tpy: $2,497 NOX > 365 tpy: $798	No sources operating in Clark County.
2103006000	NonEGU Point	Internal Combustion Engines - Gas	Ignition Retard	20	NOX < 365 tpy: $1,769 NOX > 365 tpy: $954	Some of these engines may already be meeting EPA emissions control requirements. If all emissions from the SCC are uncontrolled and meet the source category description, then maximum emissions reductions of <0.17 tpd could result from implementing this control. This measure is not necessary for attainment and cannot advance the moderate area attainment date.
2102004002	NonEGU Point	Internal Combustion Engines - Oil	Ignition Retard	25	NOX < 365 tpy: $1,335 NOX > 365 tpy: $850	Some of these engines may already be meeting EPA engine standards. If all emissions from the SCC are uncontrolled and meet the source category description, then maximum emissions reductions of <0.21 tpd could result from implementing this control. This measure is not necessary for attainment and cannot advance the moderate area attainment date.

SCC	Sector	Source Category	Emission Reduction Measure	Control Efficiency (%)	Cost Effectiveness (2018$/ton reduced)	RACM Conclusion
10300502	NonEGU Point	Internal Combustion Engines - Oil	Selective Catalytic Reduction	80	NOX < 365 tpy: $4,058 NOX > 365 tpy: $1,595	Emissions from this source category are negligible and therefore the control measure is not cost effective. This measure is not necessary for attainment and cannot advance the moderate area attainment date.
	NonEGU Point	Iron & Steel - In-Process Combustion - Bituminous Coal	Selective Catalytic Reduction	90	$4,377	No sources operating in Clark County.
	NonEGU Point	Iron & Steel - In-Process Combustion - Natural Gas and Process Gas - Coke Oven Gas	Selective Catalytic Reduction	90	$7,161	No sources operating in Clark County.
	NonEGU Point	Iron & Steel - In-Process Combustion - Natural Gas or Coke Oven Process Gas	Low NOx Burner	50	NOX < 365 tpy: $3,815 NOX > 365 tpy: $3,122	No sources operating in Clark County.
	NonEGU Point	Iron & Steel - In-Process Combustion - Process Gas -Coke Oven/ Blast Furnace	Low NOx Burner and Flue Gas Recirculation	55	NOX < 365 tpy: $5,532 NOX > 365 tpy: $4,284	No sources operating in Clark County.
	NonEGU Point	Iron & Steel - In-Process Combustion - Residual Oil	Selective Catalytic Reduction	90	$6,446	No sources operating in Clark County.
	NonEGU Point	Iron & Steel Mills - Annealing	Low NOx Burner and Selective Non-Catalytic Reduction	80	$2,983	No sources operating in Clark County.
	NonEGU Point	Iron & Steel Mills - Annealing	Low NOx Burner and Selective	90	$7,076	No sources operating in Clark County.

SCC	Sector	Source Category	Emission Reduction Measure	Control Efficiency (%)	Cost Effectiveness (2018$/ton reduced)	RACM Conclusion
			Catalytic Reduction			
	NonEGU Point	Iron & Steel Mills - Annealing	Low NOx Burner	50	$989	No sources operating in Clark County.
	NonEGU Point	Iron & Steel Mills - Annealing	Selective Non-Catalytic Reduction	60	$2,844	No sources operating in Clark County.
	NonEGU Point	Iron & Steel Mills - Annealing2	Selective Catalytic Reduction	90	$7,618	No sources operating in Clark County.
	NonEGU Point	Iron & Steel Mills - Galvanizing	Low NOx Burner and Flue Gas Recirculation	60	$1,006	No sources operating in Clark County.
	NonEGU Point	Iron & Steel Mills - Galvanizing	Low NOx Burner	50	$850	No sources operating in Clark County.
	NonEGU Point	Iron & Steel Mills - Reheating	Low Excess Air	13	$2,289	No sources operating in Clark County.
	NonEGU Point	Iron & Steel Mills - Reheating	Low NOx Burner	66	$520	No sources operating in Clark County.
	NonEGU Point	Iron and Steel Production - Annealing or Soaking Pits	Low NOx Burner and Flue Gas Recirculation	60	$1,301	No sources operating in Clark County.
	NonEGU Point	Iron and Steel Production; Blast Heating or Reheating	Low NOx Burner and Flue Gas Recirculation	77	$659	No sources operating in Clark County.
	NonEGU Point	Lean Burn ICE - NG	Air to Fuel Ratio Controller	20	NOX < 365 tpy: $1,121	No sources operating in Clark County.
	NonEGU Point	Lean Burn ICE - NG	Layered Combustion	97	NOX < 365 tpy: $43,657 NOX > 365 tpy: $1,723	No sources operating in Clark County.
	NonEGU Point	Lean Burn ICE - NG	Layered Combustion	97	$5,695	No sources operating in Clark County.

SCC	Sector	Source Category	Emission Reduction Measure	Control Efficiency (%)	Cost Effectiveness (2018$/ton reduced)	RACM Conclusion
	NonEGU Point	Lean Burn ICE - NG	Low Emission Combustion	80	NOX < 365 tpy: $1,384	No sources operating in Clark County.
	NonEGU Point	Lean Burn ICE - NG	Selective Catalytic Reduction	90	$4,013	No sources operating in Clark County.
30501604	NonEGU Point	Lime Kilns	Low NOx Burner	30	$971	This control measure could result in 0.61 tpd of emissions reductions. This measure is not necessary for attainment and cannot advance the attainment date.
	NonEGU Point	Medical Waste Incinerators	Selective Non-Catalytic Reduction	45	$7,821	No sources operating in Clark County.
	NonEGU Point	Nitric Acid Manufacturing	Extended Absorption	95	$832	No sources operating in Clark County.
	NonEGU Point	Nitric Acid Manufacturing	Non-Selective Catalytic Reduction	98	$954	No sources operating in Clark County.
	NonEGU Point	Nitric Acid Manufacturing2	Selective Catalytic Reduction	90	$1,174	No sources operating in Clark County.
	NonEGU Point	Petroleum Refinery Gas-Fired Process Heaters	Excess O3 Control	37	NOX > 25 tpy: $70	No sources operating in Clark County.
	NonEGU Point	Petroleum Refinery Gas-Fired Process Heaters	SCR-95%	84	NOX > 25 tpy: $12,352	No sources operating in Clark County.
	NonEGU Point	Petroleum Refinery Gas-Fired Process Heaters	Selective Catalytic Reduction	71	NOX > 25 tpy: $10,798	No sources operating in Clark County.
	NonEGU Point	Petroleum Refinery Gas-Fired Process Heaters	Ultra-Low NOx Burner	53	NOX > 25 tpy: $1,803	No sources operating in Clark County.
	NonEGU Point	Plastics Prod-Specific; (ABS) Resin	Low NOx Burner and Flue Gas Recirculation	55	NOX < 365 tpy: $5,532 NOX > 365 tpy: $4,284	Emissions from this source category are negligible and therefore the control measure is not cost effective. This control measure is not necessary for attainment and cannot advance the moderate area nonattainment date.
	NonEGU Point	Pri Cop Smel; Reverb Smelt Furn	Low NOx Burner and Flue	60	$1,301	No sources operating in Clark County.

SCC	Sector	Source Category	Emission Reduction Measure	Control Efficiency (%)	Cost Effectiveness (2018$/ton reduced)	RACM Conclusion
			Gas Recirculation			
2102004002 20100102	NonEGU Point	Reciprocating IC Engines - Oil	Ignition Retard	25	$1,335	This control measure could result in 0.4 tpd emission reduction from nonpoint sources; emissions from point sources are trivial. This control measure is not necessary for attainment and cannot advance the moderate area attainment date.
30500208	NonEGU Point	Sand/Gravel; Dryer	Low NOx Burner and Flue Gas Recirculation	55	NOX < 365 tpy: $5,532 NOX > 365 tpy: $4,284	Emissions from this source category are negligible and therefore the control measure is not cost effective. This measure is not necessary for attainment and cannot advance the moderate area attainment date.
	NonEGU Point	Sec Alum Prod; Smelting Furn/Reverb	Low NOx Burner	50	$989	No sources operating in Clark County.
	NonEGU Point	Solid Waste Disp;Gov;Other Incin;Sludge	Selective Non-Catalytic Reduction	45	$1,960	No sources operating in Clark County.
30301201 10500206	NonEGU Point	Space Heaters - Distillate Oil	Low NOx Burner and Flue Gas Recirculation	60	NOX < 365 tpy: $4,318 NOX > 365 tpy: $1,318	Emissions from this source category are negligible and therefore the control measure is not cost effective. This measure is not necessary for attainment and cannot advance the moderate area attainment date.
30301201 10500206	NonEGU Point	Space Heaters - Distillate Oil	Low NOx Burner	50	NOX < 365 tpy: $2,046 NOX > 365 tpy: $3,590	Emissions from this source category are negligible and therefore the control measure is not cost effective. This measure is not necessary for attainment and cannot advance the moderate area attainment date.
30301201 10500206	NonEGU Point	Space Heaters - Distillate Oil	Selective Catalytic Reduction	80	NOX < 365 tpy: $4,821 NOX > 365 tpy: $2,619	Emissions from this source category are negligible and therefore the control measure is not cost effective. This measure is not necessary for attainment and cannot advance the moderate area attainment date.

SCC	Sector	Source Category	Emission Reduction Measure	Control Efficiency (%)	Cost Effectiveness (2018$/ton reduced)	RACM Conclusion
30301201 10500206	NonEGU Point	Space Heaters - Distillate Oil	Selective Non-Catalytic Reduction	50	NOX < 365 tpy: $8,047 NOX > 365 tpy: $3,278	Emissions from this source category are negligible and therefore the control measure is not cost effective. This measure is not necessary for attainment and cannot advance the moderate area attainment date.
	NonEGU Point	Space Heaters - Natural Gas	Low NOx Burner and Flue Gas Recirculation	60	NOX < 365 tpy: $4,440 NOX > 365 tpy: $1,023	No sources operating in Clark County.
	NonEGU Point	Space Heaters - Natural Gas	Low NOx Burner	50	NOX < 365 tpy: $1,422 NOX > 365 tpy: $1,127	No sources operating in Clark County.
	NonEGU Point	Space Heaters - Natural Gas	Selective Catalytic Reduction	80	NOX < 365 tpy: $4,960 NOX > 365 tpy: $2,098	No sources operating in Clark County.
	NonEGU Point	Space Heaters - Natural Gas	Selective Non-Catalytic Reduction	50	NOX < 365 tpy: $6,711 NOX > 365 tpy: $2,723	No sources operating in Clark County.
30504033	NonEGU Point	Starch Mfg; Combined Operations	Low NOx Burner and Flue Gas Recirculation	55	NOX < 365 tpy: $5,532 NOX > 365 tpy: $4,284	Implementation of this control measure could result in 0.19 tpd of emissions reductions. This control measure is likely not cost effective. This measure is not necessary for attainment and cannot advance the moderate area attainment date.
	NonEGU Point	Steel Foundries; Heat Treating Furn	Low NOx Burner	50	$989	No sources operating in Clark County.
40201001	NonEGU Point	Surf Coat Oper;Coating Oven Htr;Nat Gas	Low NOx Burner	50	NOX < 365 tpy: $3,815 NOX > 365 tpy: $3,122	This control measure could result in 0.005 tpd emissions reductions. This control measure is not necessary for attainment and cannot advance the attainment date.
	NonEGU Point	Taconite Iron Ore Processing -	Selective Catalytic Reduction	90	$7,618	No sources operating in Clark County.

SCC	Sector	Source Category	Emission Reduction Measure	Control Efficiency (%)	Cost Effectiveness (2018$/ton reduced)	RACM Conclusion
		Induration - Coal or Gas				
	EGU	Utility Boiler - Coal/Tangential	Low NOx Coal-and-Air Nozzles with cross-Coupled Overfire Air	42	DC > 25 MW: $440	No sources operating in Clark County.
	EGU	Utility Boiler - Coal/Tangential	Low NOx Coal-and-Air Nozzles with separated Overfire Air	47	DC > 25 MW: $549	No sources operating in Clark County.
	EGU	Utility Boiler - Coal/Tangential	Low NOx Coal-and-Air Nozzles with Cross-Coupled and Separated Overfire Air	62	DC > 25 MW: $490	No sources operating in Clark County.
	EGU	Utility Boiler - Coal/Tangential	Selective Catalytic Reduction	90	25 MW < DC < 99 MW: $2,674 100 MW < DC < 299 MW: $2,269 300 MW < DC < 499 MW: $2,146 500 MW < DC < 699 MW: $2,083 DC > 700 MW: $2,019	No sources operating in Clark County.

SCC	Sector	Source Category	Emission Reduction Measure	Control Efficiency (%)	Cost Effectiveness (2018$/ton reduced)	RACM Conclusion
	EGU	Utility Boiler - Coal/Tangential	Selective Non-Catalytic Reduction	25	25 MW < DC < 99 MW: $3,470 100 MW < DC < 299 MW: $2,821 300 MW < DC < 499 MW: $2,644 500 MW < DC < 699 MW: $2,546 DC > 700 MW: $2,447	No sources operating in Clark County.
	EGU	Utility Boiler - Coal/Wall	Low NOx Burner and Over Fire Air	72	DC > 25 MW: $698	No sources operating in Clark County.
	EGU	Utility Boiler - Coal/Wall	Low NOx Burner	57	DC > 25 MW: $646	No sources operating in Clark County.
	EGU	Utility Boiler - Oil-Gas/Tangential	Selective Catalytic Reduction	80	DC > 25 MW: $1,621	No sources operating in Clark County.
	EGU	Utility Boiler - Oil-Gas/Wall	Selective Catalytic Reduction	80	DC > 25 MW: $1,621	No sources operating in Clark County.

Table 5. Analysis of Potential Point and Nonpoint VOC Control Measures for HA 212

SCC	Sector	Source Category	Emission Reduction Measure	Control Efficiency (%)	Cost Effectiveness ($/ton reduced)	RACM Conclusion
	NonEGU Point	Flexible Package Printing	Add-on controls, work practices, and material reformulation/substitution	67	$3,433	This control measure will be implemented by a CTG RACT rule.
	NonEGU Point	Generic NonEGU	Carbon Adsorber	99	$1,349	This recommendation is not associated with any industrial category.
	NonEGU Point	Generic NonEGU	Catalytic Oxidizer	99	$2,335	This recommendation is not associated with any industrial category.
	NonEGU Point	Miscellaneous Metal and Plastic Parts Coatings	Coating Reformulation	35	$2,155	This control measure will be implemented by a CTG RACT Rule.
	NonEGU Point	Flat Wood Paneling Coatings	Low-VOC materials coatings and Add-On Controls	90	$3,188	No sources operating in HA 212
	NonEGU Point	Paper Film and Foil Coatings	Low-VOC coating materials and/or add-on controls	90	$1,471	Sections 12.1.3.6(b) & (c) and Section 12.1.4.1(f) meet the CTG RACT requirement for the only stationary source in this category operating within HA 212.
	NonEGU Point	Flat Wood Paneling Coatings	Low-VOC materials coatings	60	$2,329	No sources operating in HA 212
	NonEGU Point	Large Appliance Surface Coating	Low-VOC coating materials	30	$613	No sources operating in HA 212
	NonEGU Point	Metal Furniture Coatings	Low-VOC coating materials	35	$245	No sources operating in HA 212
	NonEGU Point	Miscellaneous Industrial Adhesives	Low VOC Adhesives and Improved Application Methods	64	$322	This control measure will be implemented by a CTG RACT rule.
	NonEGU Point	Fabric Printing/ Coating and Dyeing	Permanent Total Enclosure (PTE)	97	$1,992	No sources operating in HA 212

SCC	Sector	Source Category	Emission Reduction Measure	Control Efficiency (%)	Cost Effectiveness ($/ton reduced)	RACM Conclusion
	NonEGU Point	Metal Can Surface Coating	Permanent Total Enclosure (PTE)	95	$11,538	This measure would not be cost effective and the measure is not necessary for attainment and will not advance the moderate area attainment date.
	NonEGU Point	Metal Furniture Surface Coating	Permanent Total Enclosure (PTE)	95	$28,339	No sources operating in HA 212
	NonEGU Point	Paper and Other Web Coating	Permanent Total Enclosure (PTE)	95	$2,204	No sources operating in HA 212
	NonEGU Point	Product and Package Rotogravure Printing	Permanent Total Enclosure (PTE)	96	$20,459	This measure would not be cost effective and the measure is not necessary for attainment and will not advance the moderate area attainment date.
	NonEGU Point	Generic NonEGU	Regenerative Thermal Oxidizer	99	$2,581	This recommendation is not associated with any industrial category.
	NonEGU Point	Fiberglass Boat Manufacturing	Solvent substitution, non-atomized resin application methods	35	$5,149	No sources operating in HA 212
	NonEGU Point	Miscellaneous Industrial Adhesives	Solvent Substitution	64	$325	This control measure will be implemented by a CTG RACT Rule
	NonEGU Point	Generic NonEGU	Vapor Recovery Unit	97	$25,356	This measure would not be cost effective and the measure is not necessary for attainment and will not advance the moderate area attainment date.
250101101325 010110122501 012014250101 101125010120 132501012012 2501012011	Non EGU Point	Portable Fuel Container	OTC Phase I Model Rule	65	$581/ton	This control measure might reduce VOC emissions by 1.04 tpd within 5 years or 0.201 tpd/year assuming 5 year implementation schedule and 100% rule effectiveness (OTC. 2001). This control measure is not needed for attainment and will not advance the moderate area attainment date.

SCC	Sector	Source Category	Emission Reduction Measure	Control Efficiency (%)	Cost Effectiveness ($/ton reduced)	RACM Conclusion
2501011013 2501011012 2501012014 2501011011 2501012013 2501012012 2501012011	Non EGU Point	Portable Fuel Container	OTC Phase II Model Rule/CARB Rule	58	$800-1400/ton	This control measure might reduce emissions by 0.0.61 tpd (in addition to phase I) within 5 years or 0.12 tpd/year assuming 100% rule effectiveness (OTC, 2007). This control measure is not needed for attainment and will not advance the moderate area attainment date
2461800000	Nonpoint	Agriculture - Pesticides	CARB Rule	45-70	<$14, 926	Assuming 57.5% emissions controls, this control measure could result in 0.29 tpd of emissions reductions. This measure likely is not cost effective. This control measure is not needed for attainment and will not advance the moderate area attainment date.
2302002200	Nonpoint	Commercial Cooking	Catalytic oxidizer	86%	$2,359	This measure could result in 0.16 tpd of emissions reductions and would have PM10 emission reduction co-benefits. This control measure is not necessary for attainment and will not advance the moderate area attainment date.
2610000500	Nonpoint	Construction Debris	Prohibition	100%	unknown	Section 42 already prohibits open burning of construction debris.
2680003000	Nonpoint	Composting	Cover; BMP	16%	unknown	This control measure could result in 0.12 tpd of emissions reductions. The economic feasibility of this control measure is unknown. This control measure is not necessary for attainment and will not advance the moderate area attainment date.
	Nonpoint	Adhesives and Coatings	Low VOC Coatings		unknown	This control measure might reduce VOC emissions by 0.421 tpd. The economic feasibility of this control measure is unknown. This control measure is not necessary for attainment and will not advance the moderate area attainment date.

SCC	Sector	Source Category	Emission Reduction Measure	Control Efficiency (%)	Cost Effectiveness ($/ton reduced)	RACM Conclusion
	Nonpoint	Emulsified Asphalt	Reduce VOC Content to 3% by volume		Unknown	This control measure might reduce VOC emissions by 2.29 tpd within HA 21 and 2.45 tpd if extended to the entire County assuming an 80% rule effectiveness and average material density of 7.51 lb VOC/gal before control. This measure is not needed for attainment and will not advance the moderate area attainment date.

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ATTACHMENT F:

Rate-of-Progress Emissions Inventory

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April 2024

2017 and 2026 Emission Inventories for the 15% Rate of Progress (ROP) Plan for the Clark County Ozone Nonattainment Area

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1.0 Introduction

In 2018, the US Environmental Protection Agency (EPA) designated a portion of Clark County, Nevada as a Marginal Nonattainment area under the 2015 ozone National Ambient Air Quality Standard (NAAQS) of 70 parts per billion (ppb) (Federal Register, 2018). The nonattainment boundary is defined as the Las Vegas Valley (LVV), hydrographic area 212 (HA 212), as recommended by the Nevada Division of Environmental Protection (NDEP) and Clark County (2018). Due to continued exceedances of the standard through 2020, the EPA reclassified the Clark County Nonattainment Area (HA 212) to Moderate with an attainment date of August 3, 2024, according to the 2021-2023 8-hour ozone Design Value (DV) (Federal Register, 2022; 2023). As exceedances continued through 2023, EPA will bump up the area to Serious later in 2024/25 with attainment due in 2027 according to the 2024-2026 DV.

To support an ozone attainment demonstration for the Moderate State Implementation Plan (SIP), Ramboll assisted the Clark County Department of Environment and Sustainability (DES) to develop a 15% Rate of Progress (ROP) Plan for volatile organic compound (VOC) emissions within HA 212 (Ramboll, 2023b). That work included reporting 2017 base year and projected 2023 anthropogenic emission inventories for HA 212 (Ramboll, 2023a). In response to comments from EPA on the 15% ROP Plan, DES agreed to update the Plan to reflect an extended implementation schedule for ROP control measures out to 2026.

This memorandum describes the methodologies and technical details that DES and Ramboll used to develop an updated 2017 base year and projected 2026 future year anthropogenic emissions inventory for HA 212. The purpose of this inventory is to support the revised 15% ROP Plan.

2.0 2017 and 2026 Ozone Season Day Emissions Inventory

We developed 2017 base year and 2026 future year anthropogenic ozone season weekday emission estimates for ozone precursors within HA 212 only. Specifically, the inventory represents a typical July work weekday. Figure 2-1 shows the Clark County boundary and HA 212 within Clark County. The figure also shows a grid boundary covering HA 212 used to generate emission estimates for certain source sectors using the Sparse Matrix Operator Kernel Emissions (SMOKE; UNC, 2020) processing system. The inventory includes all anthropogenic emissions categories: stationary point sources, stationary nonpoint (area) sources, on-road mobile sources, nonroad mobile sources, airports, and locomotive sources. The primary data sources for the inventory comprised locally specific activity data, the EPA's 2017 Emissions Modeling platform (EMP) based on the 2017 National Emissions Inventory (EPA, 2022), and EPA's 2016v3 EMP 2026 projections (EPA, 2023).

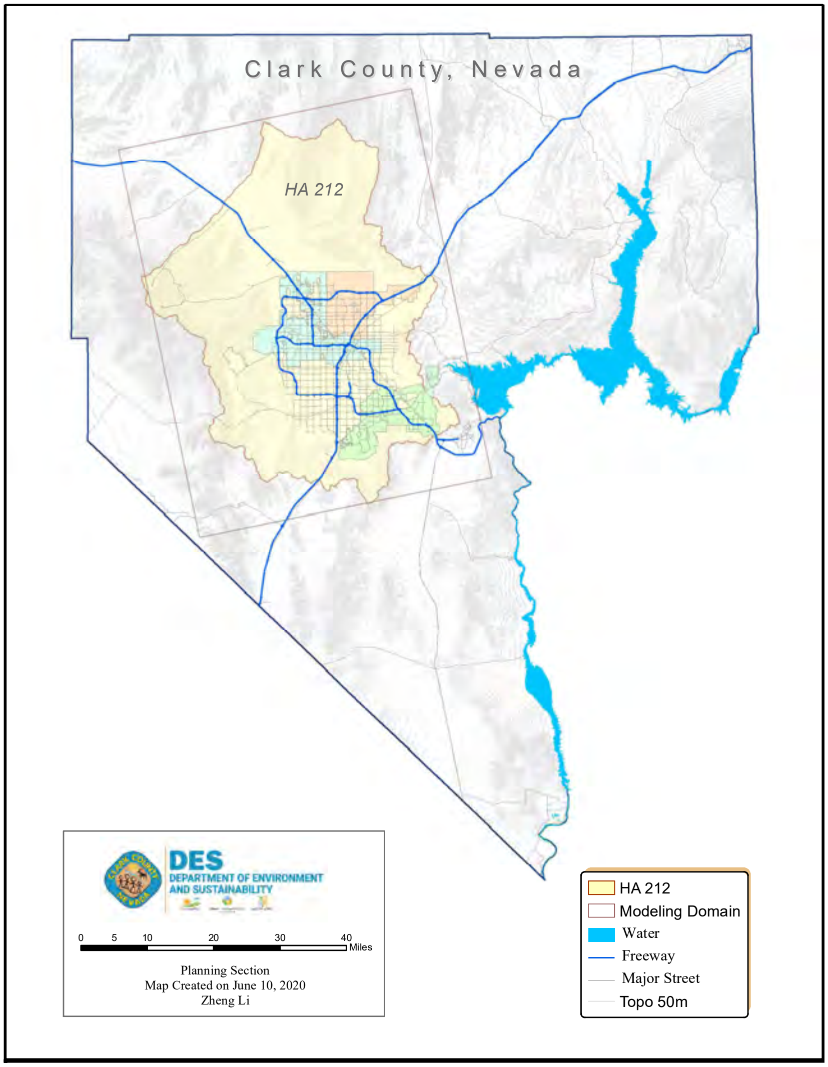


Figure 2-1. Clark County and the ozone nonattainment area (HA 212). The box covering HA 212 labeled "Modeling Domain" refers to the SMOKE emissions processing grid used to estimate HA 212 ozone season weekday emissions for certain source sectors.

The HA 212 inventory includes the effects from applicable on-the-books regulations such as the Tier 3 Motor Vehicle Emissions and Fuel Standards,[1] Final Rule for Control of Emissions of Air Pollution From Nonroad Diesel Engines and Fuel,[2] and Consumer Products: National Volatile Organic Compound Emissions Standards.[3]

[1] https://www.epa.gov/regulations-emissions-vehicles-and-engines/final-rule-control-air-pollution-motor-vehicles-tier-3, Accessed Online in September 2022.

[2] https://www.epa.gov/regulations-emissions-vehicles-and-engines/final-rule-control-emissions-air-pollution-nonroad, Accessed Online in September 2022.

[3] https://www.epa.gov/stationary-sources-air-pollution/consumer-products-national-volatile-organic-compound-emission, Accessed Online in September 2022.

Table 2-1 and Table 2-2 show 2017 and 2026 HA 212 emission estimates for VOC and NOx, respectively, by major source category, representing a typical ozone season weekday. On-road and nonroad mobile sectors are the dominant sources for NOx, followed by airports. The NOx emissions decline in 2026 is primarily due to turnover in nonroad and on-road fleets reflecting effects from federal emission controls. The nonpoint sector is the dominant anthropogenic source for VOCs followed by on-road and nonroad mobile sources. The sections below describe each source category in detail. Locomotive and airport emissions are excluded from other source categories.

Table 2-1. Summary of HA 212 ozone season weekday VOC emissions (tons per day, TPD).

Source Category	2017 Base VOC (TPD)	2026 Base VOC (TPD)	Difference (%)
Point source	1.25	1.35	8%
Nonpoint source	57.72	61.69	7%
On-road mobile	24.81	14.60	-41%
Non-road mobile	24.03	24.25	1%
Airports (commercial & Federal)	1.96	2.75	40%
Locomotives	0.04	0.03	-25%
ERC		0.05	
Total	**109.81**	**104.72**	**-5%**

Table 2-2. Summary of HA 212 ozone season weekday NOx emissions (tons per day, TPD).

Source Category	2017 Base NOx (TPD)	2026 Base NOx (TPD)	Difference (%)
Point source	2.92	3.38	16%
Nonpoint source	6.15	6.53	6%
On-road mobile	37.91	14.12	-63%
Non-road mobile	36.98	19.10	-48%
Airports (commercial & Federal)	11.90	15.90	34%
Locomotives	0.80	0.62	-23%
ERC		0.92	
Total	**96.66**	**60.57**	**-37%**

3.0 On-road Mobile Source Emissions

On-road mobile sources include automobiles, motorcycles, buses, and trucks traveling on local roads and state and national highways. The emissions estimates were developed from the EPA's MOtor Vehicle Emissions Simulator, version 4 (MOVES4[4]), the latest release available at the time of analysis. Ramboll ran MOVES4 in inventory mode to generate on-road mobile source emissions estimates for a typical July weekday within HA 212.

[4] https://www.epa.gov/moves/latest-version-motor-vehicle-emission-simulator-moves.

3.1 MOVES Inputs

MOVES4 includes 13 source types (Table 3-1) and four roadway types (Table 3-2). DES developed MOVES inputs representing Clark County for the 2017 base year and the 2026 future year. These inputs were based on the latest available information and data sources to ensure accuracy and representativeness. Once the input databases were developed, the HA 212 sub-county input databases were also prepared based on either actual activity data or spatial surrogates. Subsequently, Ramboll ran the MOVES4 model with the databases for HA 212 to generate the ozone precursor inventories for the on-road source category.

Table 3-1. MOVES source types.

Source Type ID	MOVES Source Type Name
11	Motorcycle
21	Passenger Car
31	Passenger Truck
32	Light Commercial Truck
41	Other Buses
42	Transit Bus
43	School Bus
51	Refuse Truck
52	Single Unit Short-haul Truck
53	Single Unit Long-haul Truck
54	Motor Home
61	Combination Short-haul Truck
62	Combination Long-haul Truck

Table 3-2. Map of Highway Performance Monitoring System (HPMS) road types to MOVES road types.

<table>
<tr><th>HPMS Road Type</th><th>MOVES Road Type</th></tr>
<tr><td>11: Rural Principal Arterial – Interstate</td><td>2: Rural Restricted Access</td></tr>
<tr><td>13: Rural Principal Arterial - Other</td><td rowspan="5">3: Rural Unrestricted Access</td></tr>
<tr><td>15: Rural Minor Arterial</td></tr>
<tr><td>17: Rural Major Collector</td></tr>
<tr><td>19: Rural Minor Collector</td></tr>
<tr><td>21: Rural Local System</td></tr>
<tr><td>23: Urban Principal Arterial – Interstate</td><td rowspan="2">4: Urban Restricted Access</td></tr>
<tr><td>25: Urban Principal Arterial – Other Freeways</td></tr>
<tr><td>27: Urban Principal Arterial – Other</td><td rowspan="4">5: Urban Unrestricted Access</td></tr>
<tr><td>29: Urban Minor Arterial</td></tr>
<tr><td>31: Urban Collector</td></tr>
<tr><td>33: Urban Local System</td></tr>
</table>

The key MOVES inputs include vehicle fleet activity data such as vehicle miles traveled (VMT), vehicle population by vehicle source type (or vehicle class), fleet age distribution, fuel parameters, and inspection and maintenance (I/M) programs.

3.1.1 Clark County Vehicle Classification Study

Since vehicle classification is a crucial component for developing an on-road emission inventory, DES completed a vehicle classification study in June 2018. The study used 2014-2016 traffic count data collected by the Nevada Department of Transportation (NDOT) and included an on-road license plate survey at selected roadway locations. The collected license plate numbers were matched to vehicle identification numbers (VIN), then decoded to obtain vehicle attributes that allowed DES's contractor to classify cars versus light-duty trucks. The primary products of the vehicle classification study included VMT mix and temporal profiles, which were incorporated into the 2017 MOVES input database. The MOVES temporal profiles included monthly, weekly, and hourly traffic profiles.

<u>VMT Mix Profiles</u>

Figure 3-1 shows the VMT mix profiles from the DES study by MOVES road type. Rural Restricted Access (Road Type 2) has the highest amount of heavy-duty VMT (24%), which decreases from left to right in the figure: from Road Type 2 to Rural Unrestricted Access (Road Type 3) to Urban Restricted Access (Road Type 4) to Urban Unrestricted (Road Type 5).

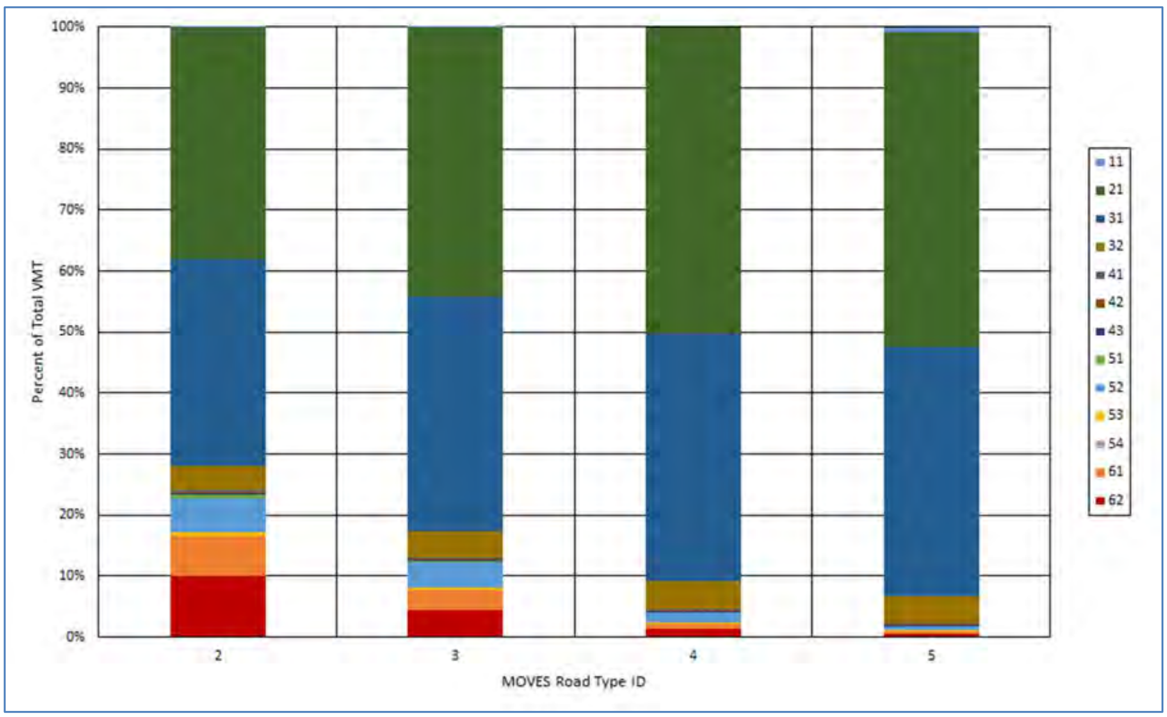


Figure 3-1. Summary of VMT mix by vehicle type on each MOVES road type. Vehicle types are listed in Table 3-1.

<u>Monthly Traffic Profiles</u>

Figure 3-2 displays the monthly VMT profiles for MOVES. The MOVES model distributes annual VMT to monthly totals using the monthly VMT fractions shown in Figure 3-2. Clark County's monthly variation does not indicate a strong seasonal influence on VMT. These monthly variations are based on the NDOT traffic counts during 2014-2016. NDOT has continuous traffic counters operating throughout the year.

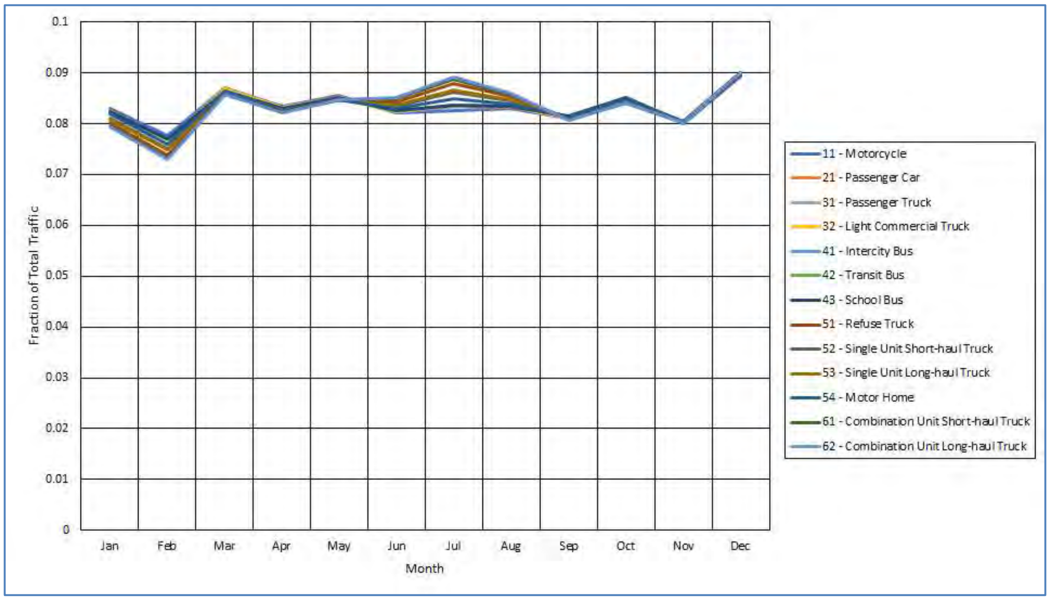


Figure 3-2. MOVES monthly VMT fractions for Clark County, NV.

Weekly Traffic Profiles

The day-of-week profiles in MOVES apportion weekly VMT to two periods of the week: "weekday," consisting of 5 days, and "weekend," consisting of 2 days. Figure 3-3 shows a sample of the profiles for passenger cars. The ratio of weekday to weekend VMT grows from left to right, moving from Rural (Road Types 2 and 3) to Urban (Road Types 4 and 5). This pattern of higher weekday VMT on urban roads and unrestricted roads was generally true for all the source types.

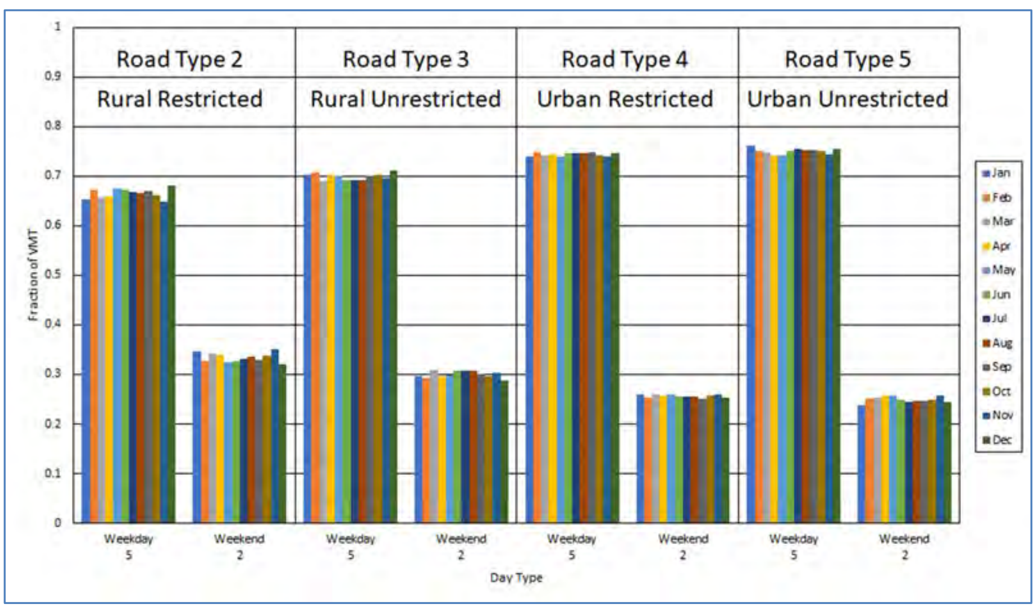


Figure 3-3. An Example of MOVES VMT fractions (passenger cars) by day-of-week type.

Hourly Traffic Profiles

Figure 3-4 shows a sample of MOVES hourly VMT fractions for passenger cars traveling on weekdays (solid line series) and weekends (broken line series) in Clark County for each of the four MOVES road types. On weekdays, the two Urban Road Types—4 (grey) and 5 (yellow)—have prominent morning peaks in the VMT fractions. Weekend profiles on all road types reach their high point midday, i.e., between the hours of about noon to 4 PM.

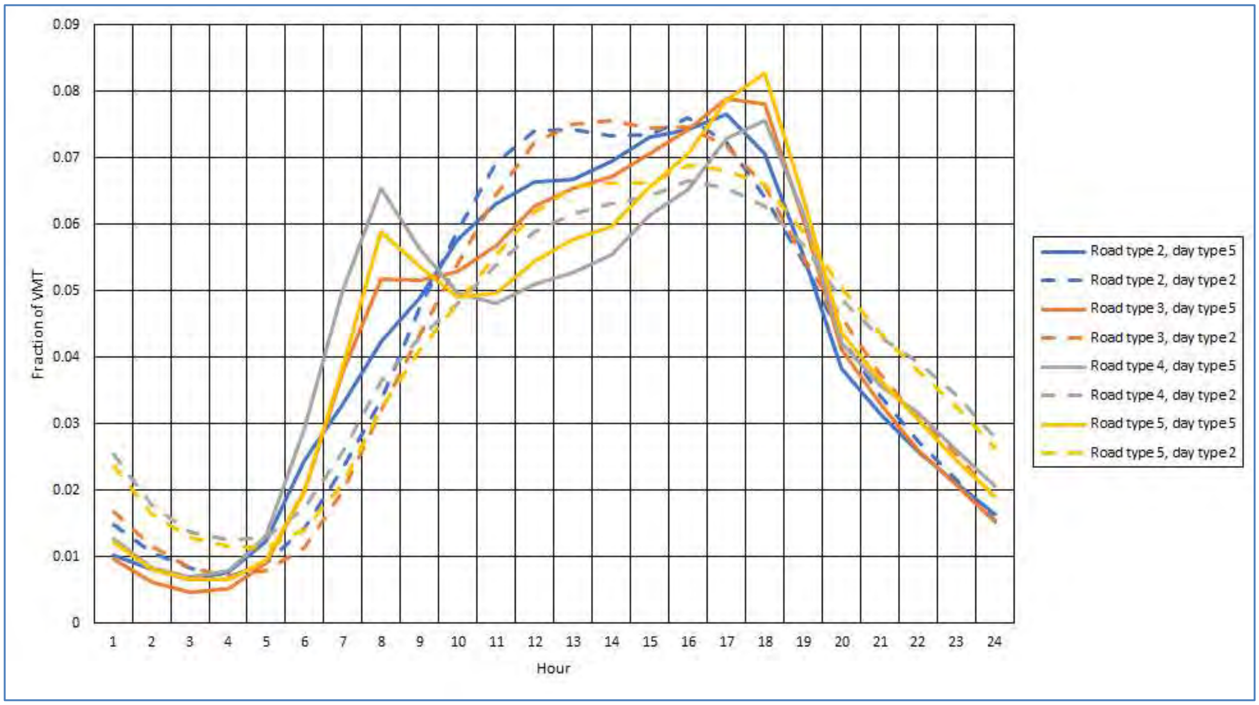


Figure 3-4. An example of MOVES hourly VMT Fractions (passenger cars).

3.1.2 Other MOVES Inputs

Activity data for each vehicle type, such as VMT and vehicle population, are important inputs for MOVES. VMT data for the base year (2017) inventory are derived from NDOT's 2017 annual Highway Performance Monitoring System (HPMS) reports. Per special request, NDOT also provided DES with VMT data for the HA 212 sub-county area, which was used for on-road inventory development.

The MOVES model requires annual or daily VMT by vehicle type. Using the VMT mix information developed from the Clark County Vehicle Classification Study, DES generated annual VMTs for each vehicle source type for HA 212. Table 3-3 shows Clark County 2017 annual VMTs by function class within HA 212 from NDOT.

For urban road types, 2026 VMT was projected from 2017 using growth factors from forecasts derived from travel demand modeling conducted by the Regional Transportation Commission of Southern Nevada (RTC). For rural road types, a linear regression projection from historical NDOT HPMS reports was used to project VMT. Table 3-4 lists annual VMT by source type for the two modeling years.

Table 3-3. Clark County 2017 annual VMT by function class within HA 212.

Function Class	2017 Annual VMT
Rural Interstate	37,956,020
Rural Other Principal Arterial	71,177,655
Rural Minor Arterial	0
Rural Major Collector	45,745,974
Rural Minor Collector	1,218,372
Rural Local	8,512,560
Urban Interstate	3,158,264,116
Urban Other Freeways and Expressways	1,509,145,790
Urban Other Principal Arterial	2,045,321,410
Urban Minor Arterial	3,937,878,139
Urban Collector	1,617,429,935
Urban Local	4,118,471,242
Annual Total	**16,551,121,213**

Table 3-4. Clark County annual VMT by vehicle type within HA 212.

Source Type ID	Source Type Name	2017	2026
11	Motorcycle	93,203,739	110,688,308
21	Passenger Car	8,396,862,937	9,972,073,598
31	Passenger Truck	6,754,358,072	8,021,442,807
32	Light Commercial Truck	722,814,819	858,411,365
41	Other Buses	45,433,736	49,716,622
42	Transit Bus	28,032,592	33,802,966
43	School Bus	21,850,000	29,677,620
51	Refuse Truck	12,033,030	14,290,368
52	Single Unit Short-haul Truck	202,484,000	240,469,014
53	Single Unit Long-haul Truck	10,078,340	11,968,988
54	Motor Home	1,640,285	1,947,994
61	Combination Short-haul Truck	140,293,750	166,612,175
62	Combination Long-haul Truck	122,035,913	144,929,257
Total:		**16,551,121,213**	**19,656,031,081**

DES derived the vehicle type population data for the entire county primarily from the Nevada Department of Motor Vehicle (DMV) registration database. Adjustments were made for transit buses based on data obtained from the RTC and for school bus populations based on reports from the online magazine SchoolBus. Vehicle population estimates for combination short-haul and long-haul trucks were based on MOVES default database. The vehicle populations by source type were projected from 2017 to 2026 using surrogates such as human population for light duty vehicles, and VMT for heavy duty trucks. For the HA 212 sub-county area, vehicle population by source type was adjusted from county-level using human population as a surrogate. Based on census data for human population distribution, DES assumed that the source type population within HA 212 is about 95 percent of the total source type population of Clark County. Table 3-5 lists the source type populations used in the model for the years 2017 and 2026.

Table 3-5. Clark County vehicle population within HA 212.

Source Type ID	Source Type Name	2017	2026
11	Motorcycle	40,367	48,316
21	Passenger Car	679,162	812,889
31	Passenger Truck	529,309	633,530
32	Light Commercial Truck	56,644	67,797
41	Other Buses	355	425
42	Transit Bus	797	856
43	School Bus	1,859	2,225
51	Refuse Truck	601	712
52	Single Unit Short-haul Truck	15,575	18,459
53	Single Unit Long-haul Truck	1,102	1,307
54	Motor Home	865	1,025
61	Combination Short-haul Truck	4,285	5,079
62	Combination Long-haul Truck	6,891	8,168
Total:		**1,337,813**	**1,600,787**

MOVES also requires input from hoteling activity, which refers to the hours spent idling by drivers of diesel long-haul combination trucks during mandatory rest periods. MOVES accounts for idling and auxiliary power unit (APU) use as separate emission processes, in addition to truck operation on roadways. Since no local specific hoteling hours are available, hoteling hours were based on MOVES4 default.

Ambient temperature and humidity data were based on the meteorological data collected at Harry Reid International Airport (LAS) in 2017. Table 3-6 presents the average hourly temperature and humidity data used in the MOVES database for July 2017.

Table 3-6. Average hourly temperature and humidity at McCarran International Airport for July 2017.

Hour	Temperature (F)	Humidity (%)
1	90.7	25.7
2	89.4	26.8
3	88.3	28.0
4	87.0	29.7
5	86.1	31.1
6	87.5	30.0
7	90.3	27.7
8	92.3	28.5
9	94.9	25.5
10	97.3	23.9
11	99.6	22.1
12	101.7	19.5
13	103.1	18.4
14	103.7	17.9
15	104.3	16.4
16	104.1	16.5
17	104.1	16.3
18	102.8	16.6
19	100.8	18.1
20	98.8	19.9
21	96.9	21.3
22	95.2	22.1
23	93.5	23.4
24	91.9	25.6

The DMV provided vehicle registration data for Clark County by model year and vehicle type, which DES used to generate the vehicle population and vehicle age distribution inputs. The age distributions for 2017 were based on the vehicle registration data from DMV for light-duty vehicle types; age distributions for heavy-duty vehicle types were exported from the MOVES3.1 default database. However, DES found a better source of data for age distribution from a national project conducted by the Coordinated Research Council (CRC). The project performed VIN decoding of 2017 county-specific registration data from IHS Markit, a global information services provider. The age distributions derived from the VIN-decoding project have been used by EPA in their 2016 modeling platform and 2017 NEI development. EPA purchased the county-specific data from IHS Markit for the entire U.S. DES believes that the age distributions in the 2017 NEI are more robust and were therefore used in Clark County's on-road inventory.

EPA recently developed an age distribution projection tool for the 2016v2 modeling platform that includes a new method to ensure the dip in light-duty vehicle sales during the 2008–09 recession is reflected for the same model years at a future time. In other words, the tool adjusts the age distributions of light-duty source types from the base year to future years. DES used this new age-distribution projection tool to adjust the light-duty source types from the base year of 2017 to the future year of 2026. The future-year age distributions for heavy-duty source types were kept the same as those in the base year of 2017, consistent with the assumption used in the 2016v2 modeling platform.

CRC also sponsored several projects aimed at improving the on-road portion of the NEI. Vehicle speed distribution is a crucial component of on-road emission inventories. For the Clark County 2017 MOVES database, the average vehicle speed distributions from 16 MOVES speed bins for each vehicle type were based on the CRC-sponsored project A-100, which used StreetLight Vehicle Telematics Data. DES used the same speed distributions for the future year of 2026, consistent with the assumption used in the 2016v2 modeling platform.

DES also used fuel parameters from the MOVES default database. Both gasoline and diesel sulfur levels are required to meet EPA requirements for low sulfur content as part of the Tier 2 standard (before 2017) or the Tier 3 standard (after 2017). Nevada caps the fuel Reid vapor pressure in Clark County at 9.0 pounds per square inch (psi), with a 1.0-psi waiver for ethanol-blended fuels.

Information regarding vehicle I/M programs is another important input for the MOVES model. In the Las Vegas Valley, the state I/M program requires an annual two-speed idle test for 1995 and older vehicles, and on-board diagnostics checks (exhaust and evaporative) for 1996 and newer vehicles. In the past, the I/M program exempted a new vehicle from emissions testing for the first 2 years. During the 2021 legislative session, Nevada Bill AB 349 changed the I/M grace period from 2 years to 3 years. DES incorporated this information into MOVES modeling using a 2-year grace period for 2017 and a 3-year grace period for 2026.

3.2 On-road Mobile Emissions Estimates

Table 3-7 shows HA 212 summer weekday on-road emission estimates for 2017 and 2026. Ramboll ran MOVES4 for a typical July weekday using meteorological data in Table 3-6 to represent typical summertime on-road NOx and VOC emissions. Emission estimates for both ozone precursors significantly decrease from 2017 to 2026 due to fleet turnover with the implementation of stringent emissions control limits such as Tier 3 standards, which phase in starting in 2017.

Table 3-7. Clark County on-road mobile emissions in July (TPD) within HA 212.

Pollutant	2017	2026
VOC	24.81	14.60
NO_x	37.91	14.12

4.0 Nonroad Source Emissions

Nonroad mobile sources include a wide variety of motorized equipment types that either move under their own power off the roadway network or can be moved from site to site. The nonroad mobile source 2017 and 2026 emissions estimates were taken from the 2017 EMP and the 2016v3 EMP 2026 projections, respectively, which are based on the nonroad module of MOVES (EPA, 2020).

To develop HA 212 sub-county ozone season weekday emissions estimates, SMOKE was run for weekdays of a single week (Monday through Friday) in July (without a holiday) on a grid covering the nonattainment areas with 4 km grid spacing (Figure 2-1) using monthly nonroad emissions data by Source Classification Code (SCC) in the FF10 flat data file format. The total emission estimates within the modeling domain were summed for NOx and VOC and averaged over all five weekdays. Several ancillary (e.g., cross-references) data files are required when running SMOKE. We used the ancillary files from respective EMPs. The resulting HA 212 nonroad emissions are provided by SCC in Appendix A. Table 4-1 shows July 2017 and 2026 average weekday total nonroad emissions within HA 212.

Table 4-1. Clark County nonroad emissions in July (TPD) within HA 212.

Pollutant	2017	2026
VOC	24.03	24.25
NO_x	36.98	19.10

5.0 Nonpoint Source Emissions

Nonpoint sources are stationary sources that fall below point source reporting levels and are too numerous or small to identify individually, e.g., small-scale industrial or residential operations that use emission-generating materials or processes. We accessed the 2017 and 2026 nonpoint emissions from the 2017 EMP and the 2016v3 EMP 2026 projections, respectively, to develop the Clark County ozone HA 212 inventory. The nonpoint source category includes locomotive, volatile chemical products (VCP), commercial combustion, asphalt paving, residential wood combustion, and other area sources. The 2016v3 EMP uses EPA's new approach and data to derive emissions for VCP sources; the 2017 EMP and previous emissions inventories reported VCP emissions based on an older methodology. To obtain 2017 VCP estimates based on a consistent methodology, we linearly interpolated VCP emissions reported in the 2016v3 EMP between 2016 and 2023 instead of using emissions from the 2017 EMP. Table 5-1 provides a detailed overview of annual VOC emissions from VCP sources in Clark County for the years 2016, 2017 (interpolated), and 2026.

Table 5-1. Clark County VCP VOC emissions by SCC interpolated to 2017.

SCC	SCC Description	2016 (tons/year)	2023 (tons/year)	Interpolated 2017 (tons/year)
2401001000	Architectural Coatings	1733	1922	1760
2401005000	Auto Refinishing: SIC 7532	155	172	158
2401008000	Traffic Markings	298	331	303
2401015000	Factory Finished Wood: SIC 2426 thru 242	3	3	3
2401020000	Wood Furniture: SIC 25	43	48	44
2401025000	Metal Furniture: SIC 25	55	61	56
2401030000	Paper: SIC 26	0	0	0
2401055000	Machinery and Equipment: SIC 35	5	6	5
2401065000	Electronic and Other Electrical: SIC 36 - 363	16	18	17
2401070000	Motor Vehicles: SIC 371	6	6	6
2401075000	Aircraft: SIC 372	0	0	0
2401090000	Surface Coating: Miscellaneous Manufacturing	39	43	40
2401100000	Industrial Maintenance Coatings	526	583	534
2401200000	Other Special Purpose Coatings	244	271	248
2415000000	Degreasing: All Processes/All Industries	230	230	230
2420000000	Dry Cleaning	12	12	12
2425000000	Graphic Arts	792	878	804
2460030999	C&C: Lighter Fluid, Fire Starter, Other Fuels	47	52	48
2460100000	C&C: Personal Care Products	3143	3486	3192
2460200000	C&C: Household Products	2388	2648	2425
2460400000	C&C: Automotive Aftermarket Products	295	327	300
2460500000	C&C: Coatings and Related Products	2344	2599	2381
2460600000	C&C: Adhesives and Sealants	2077	2304	2110
2460800000	C&C: FIFRA Related Products	169	187	172
2460900000	C&C: Miscellaneous Products (Not Otherwise Covered)	40	44	40
2461021000	Cutback Asphalt	303	303	303
2461022000	Emulsified Asphalt	1226	1226	1226
2461850000	Pesticide Application: Agricultural	1	1	1
Total:		**16,192**	**17,762**	**16,416**

SMOKE was run on the HA 212 grid (Figure 2-1) for weekdays of a single week (Monday through Friday) in July (without a holiday) to generate ozone season weekday emission estimates using annual nonpoint emissions data by SCC in FF10 flat data file formats. The total emission estimates within the modeling domain were summed for NOx and VOC and averaged over all five weekdays. When running SMOKE, several ancillary (e.g., cross-references) data files are required. We used the ancillary data files from respective EMPs. The resulting HA 212 nonpoint emissions are provided by SCC in Appendix A. Table 5-2 shows July 2017 and 2026 average weekday total locomotive emissions[5] within HA 212. Similarly, Table 5-3 shows July 2017 and 2026 average weekday emissions for other nonpoint sources, excluding locomotives, within HA 212.

Table 5-2. Clark County locomotive July weekday emissions (TPD) within HA 212.

Pollutant	2017	2026
VOC	0.04	0.03
NO_x	0.80	0.62

Table 5-3. Clark County nonpoint emissions in July (TPD) within HA 212.

Pollutant	2017	2026
VOC	57.72	61.69
NO_x	6.15	6.53

6.0 Point Source Emissions

Point sources are larger stationary sources that emit above mandatory reporting levels and must be permitted. Examples include power plants, industrial boilers, and various other industrial/commercial facilities. Clark County's point source inventory includes all Title V stationary and all minor sources with the potential to emit at least 10 tons of VOCs or 25 tons of NOx that are located within HA 212. Point source 2017 emissions inventories were obtained from 2017 annual reports submitted by individual stationary sources. Emissions for 2026 were estimated by extrapolating from the 2017 emissions using growth factors derived from the Technical Support Document of Second Maintenance Plan for the 1997 8-hour Ozone NAAQS (DES, 2021a). Point source emission inventories were developed from either data collected by direct on-site measurements or calculated using EPA emission factors and activity data. Emissions from all minor sources emitting less than 10 tons of VOCs or 25 tons of NOx were included in the nonpoint source category.

Table 6-1 provides the overall NOx and VOC point source emissions for 2017 and 2026. The resulting HA 212 point source emissions by individual unit are listed in Appendix B.

Table 6-1. Clark County point source emissions within HA 212 (tons per summer day).

Pollutant	2017	2026
VOC	1.25	1.35
NO_x	2.92	3.38

[5] The SCC codes used to calculate the locomotive emissions are in provided in Appendix A, Table A1, page A-3.

7.0 Commercial Aviation

Commercial aviation within HA 212 covers emissions from three primary airports: Harry Reid (McCarran) International Airport, North Las Vegas Airport, and Henderson Executive Airport. The Clark County Department of Aviation (DOA) has provided emissions data for the year 2017, as well as projections for 2023 and 2032. These emission inventories were developed using the Federal Aviation Administration's Aviation Environmental Design Tool (AEDT), Version 3b. The 2026 emissions were estimated by interpolating from 2023 and 2032 emissions data. DOA calculated design day emissions using the default meteorology in AEDT. The design day was in October, so DOA developed correction factors to account for the differences in meteorology between the design day and a typical summer weekday. These correction factors were applied to the emission inventories for all the airports. Table 7-1 presents 2017 and 2026 emissions for commercial aviation.

Table 7-1. Commercial aviation emissions (tons per summer day).

	2017		2026	
Airport	**NOx**	**VOC**	**NOx**	**VOC**
Harry Reid (McCarran) International Airport	10.95	1.11	12.75	1.14
North Las Vegas Airport	0.24	0.38	0.24	0.39
Henderson Executive Airport	0.21	0.21	0.24	0.23
Total	**11.40**	**1.72**	**13.23**	**1.77**

8.0 Federal Aviation

Federal aviation emissions within HA 212 primarily originate from Nellis Air Force Base. Table 8-1 presents 2017 actual and 2026 projected emissions from aircraft operations obtained from Clark County's 1997 8-hour Ozone Second Maintenance Plan (DES, 2021a). The 2026 emissions were estimated by interpolating from the 2023 and 2033 emissions.

Table 8-1. Federal aviation emissions for 2017 (actual) and 2026 (projected).

	2017		2026	
Airport	**NOx**	**VOC**	**NOx**	**VOC**
Nellis Air Force Base	0.50	0.24	2.18	0.90
Air Force Training Project			0.49	0.08
Total	**0.50**	**0.24**	**2.67**	**0.98**

9.0 Banked Emission Reduction Credits (ERC)

Emission Reduction Credits (ERCs) may be granted, under strict guidelines, upon request by an emissions source that voluntarily reduces emissions beyond required levels of control. ERCs may be sold, leased, banked for future use, or traded in accordance with applicable regulations. When used to offset emissions, they are permanently retired. ERCs are intended to provide an incentive for reducing emissions and to establish a framework to promote a market-based approach to regulating air pollution. Tables 9-1 and 9-2 outline the ERCs currently banked in Clark County for HA 212.

Table 9-1. ERC Balance for NOx within HA 212.

Owner ID – Name	ERC Balance
4 - CERTAIN TEED CORPORATION	16.5
3 - CHEMICAL LIME COMPANY	78.7
347 - MORGAN ADHESIVES COMPANY / MACTAC	1
99 - NEVADA READY MIX	60.4
477 - NV ENERGY	13.78
279 - SILVER STATE MATERIALS CORP.	9
19 - TITANIUM METALS CORP. (TIMET)	157.8
Total (TPY)	337.18
Total (TPD)	**0.92**

Table 9-2. ERC Balance for VOC within HA 212.

Owner ID – Name	ERC Balance
4 - CERTAIN TEED CORPORATION	0.13
347 - MORGAN ADHESIVES COMPANY / MACTAC	17.5
99 - NEVADA READY MIX	1.3
477 - NV ENERGY	0.08
279 - SILVER STATE MATERIALS CORP	0.7
Total (TPY)	19.71
Total (TPD)	**0.05**

10.0 Quality Assurance of Emissions

We performed thorough Quality Assurance (QA) and Quality Control (QC) checks of emissions following the procedures developed by WRAP (Adelman, 2004) for all source categories. We leveraged SMOKE's advanced quality assurance features that include error logs when emissions are dropped or added during emissions processing. We carefully reviewed SMOKE log files for each processing stream and resolved any errors or critical warning messages before making a final SMOKE run. The QA activities of emissions data for each source category are described below.

For on-road mobile sources, most input datasets were generated from a locally specific vehicle study, and these datasets were carefully reviewed and checked. Some input datasets were submitted to EPA through the Emissions Inventory System (EIS), which includes several QA and QC checks. The MOVES model also includes internal checks and we made sure that all input datasets were properly imported into the MySQL database with all green checks showing before running the model. The output database was carefully reviewed, and we made sure there were no error messages. The emissions outcomes were reviewed and compared to other inventory data such as inventories from the NEI, different years, and other counties for reasonableness and consistency.

For nonroad and nonpoint sources, the primary data sources for the inventory were the 2017 Emissions Modeling platform (EMP) based on the 2017 NEI (EPA, 2022), and the 2016v3 EMP 2026 projections (EPA, 2023). EPA performed QA/QC checks on these datasets, and we thoroughly reviewed them. We used these inventories and the SMOKE modeling system for the 2016v3 platform without modification to develop emissions for HA 212. The emission outcomes were compared to those from NEI and other counties for reasonableness and consistency. The spatial distribution of emissions was checked with gridded emissions maps. Figures 10-1 and 10-2 illustrate the spatial distribution of NOx and VOC emissions in both 2017 and 2026 for these sectors. The emissions maps consistently align with the distribution of population and housing density within HA 212, showcasing correct spatial allocation of emissions. The point source emission inventories submitted by facilities were checked by the DES compliance staff following procedures outlined in the Emissions Inventory Report Review and Audit Process (DES, 2021b).

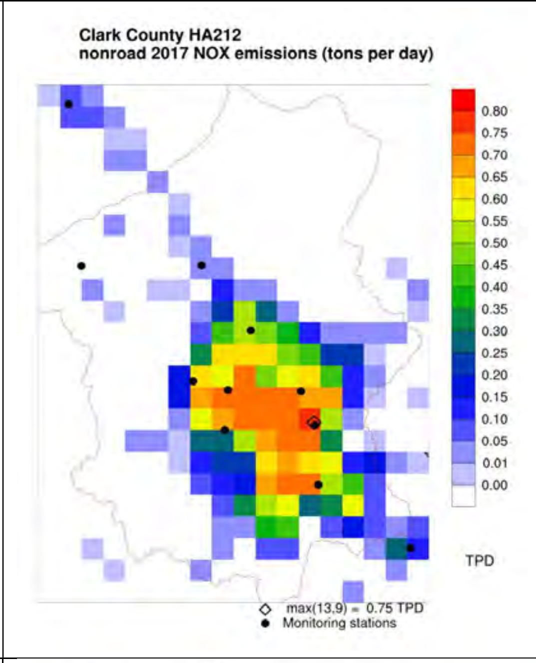
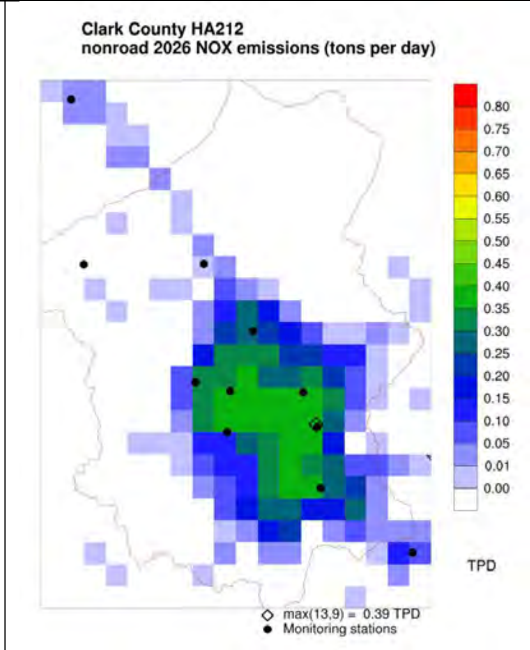
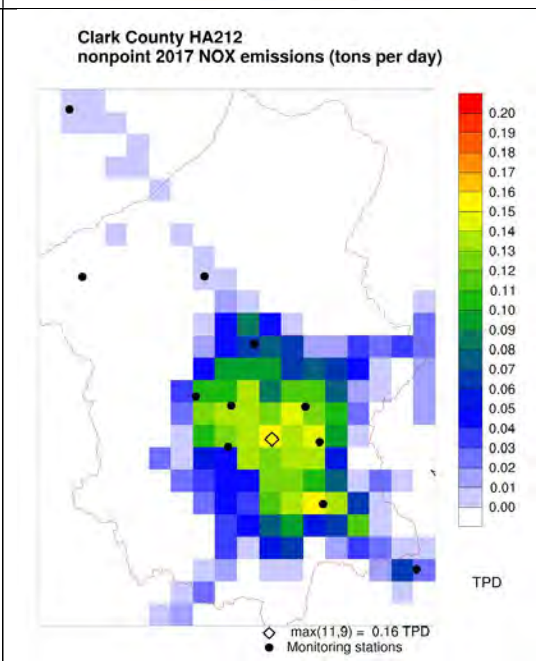
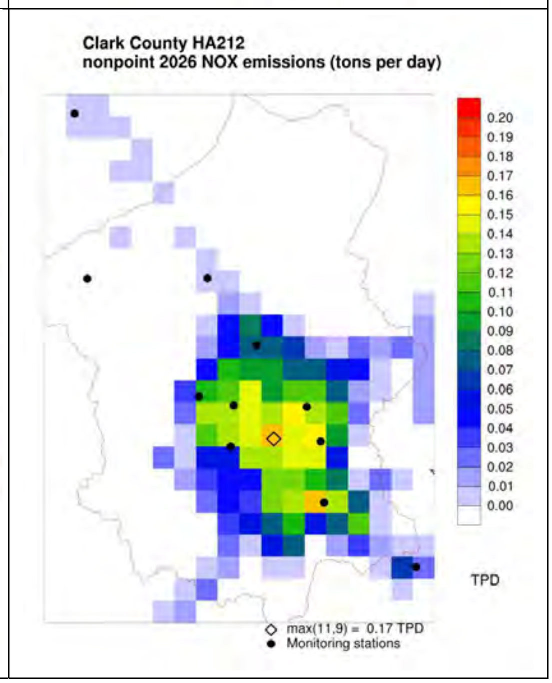
<table>
<tr><th>NOx</th><th>2017</th><th>2026</th></tr>
<tr><td>Nonroad</td><td>
</td><td>
</td></tr>
<tr><td>Nonpoint</td><td>
</td><td>
</td></tr>
</table>

Figure 10-1. July weekday average NOx emissions for nonroad (top row) and nonpoint (bottom row) sectors presented for the years 2017 (left column) and 2026 (right column).

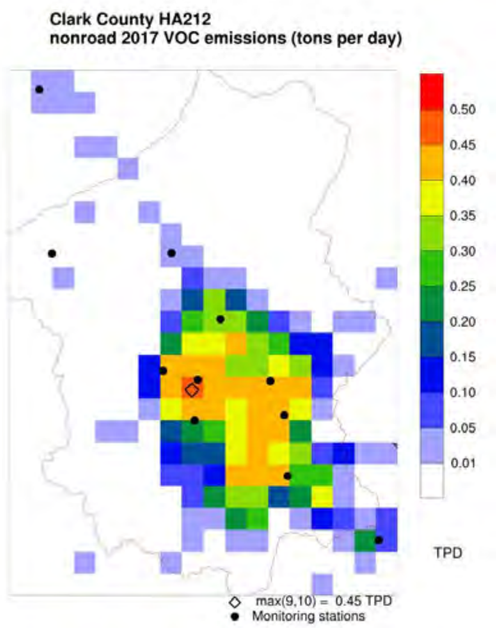
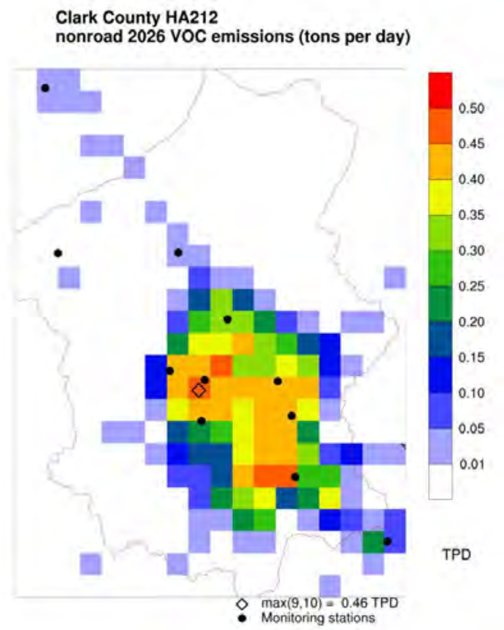
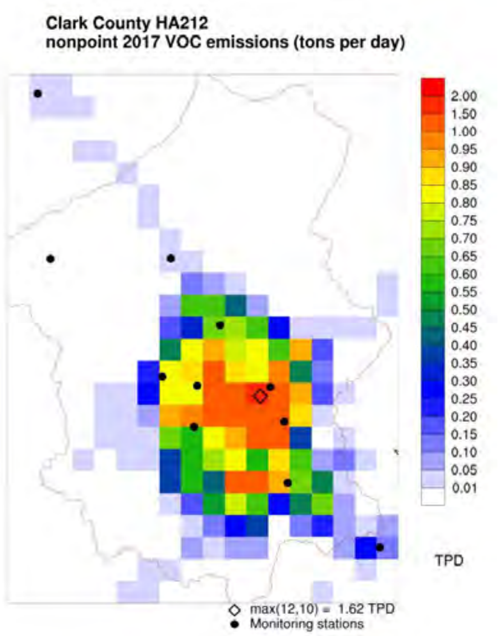
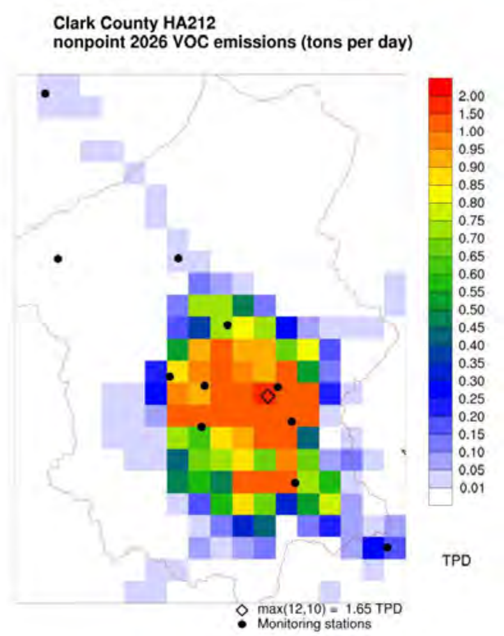
<table>
<tr><th>VOC</th><th>2017</th><th>2026</th></tr>
<tr><td>Nonroad</td><td>
</td><td>
</td></tr>
<tr><td>Nonpoint</td><td>
</td><td>
</td></tr>
</table>

Figure 10-2 July weekday average VOC emissions for nonroad (top row) and nonpoint (bottom row) sectors presented for the years 2017 (left column) and 2026 (right column).

11.0 References

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Appendix A Clark County Nonattainment Area Nonpoint and Nonroad (Including Locomotive) Emissions by SCC

Appendix A Clark County Nonattainment Area Nonpoint and Nonroad (Including Locomotive) Emissions by SCC

Table A1. HA 212 ozone season weekday nonpoint (including locomotives) emissions by SCC.

SCC	SCC Description	2017 (TPD)		2026 (TPD)	
		NOX	VOC	NOX	VOC
2102002000	Stationary Source Fuel Combustion; Industrial; Bituminous/Subbituminous Coal; Total: All Boiler Types	0.2112	0.0010	0.1813	0.0008
2102004001	Stationary Source Fuel Combustion; Industrial; Distillate Oil; All Boiler Types	0.1089	0.0011	0.1366	0.0014
2102004002	Stationary Source Fuel Combustion; Industrial; Distillate Oil; All IC Engine Types	2.1933	0.1525	2.7510	0.1913
2102006000	Stationary Source Fuel Combustion; Industrial; Natural Gas; Total: Boilers and IC Engines	0.9840	0.0541	0.9923	0.0683
2102007000	Stationary Source Fuel Combustion; Industrial; Liquified Petroleum Gas (LPG); Total: All Boiler Types	0.0656	0.0024	0.0075	0.0003
2102008000	Stationary Source Fuel Combustion; Industrial; Wood; Total: All Boiler Types	0.0229	0.0018	0.0224	0.0017
2103004001	Stationary Source Fuel Combustion; Commercial/Institutional; Distillate Oil; Boilers	0.0007	<0.0001	0.0007	<0.0001
2103004002	Stationary Source Fuel Combustion; Commercial/Institutional; Distillate Oil; IC Engines	0.0011	0.0001	0.0011	0.0001
2103006000	Stationary Source Fuel Combustion; Commercial/Institutional; Natural Gas; Total: Boilers and IC Engines	1.9344	0.1064	1.8027	0.1158
2103007000	Stationary Source Fuel Combustion; Commercial/Institutional; Liquified Petroleum Gas (LPG); Total: All Combustor Types	0.0750	0.0027	0.0750	0.0027
2103008000	Stationary Source Fuel Combustion; Commercial/Institutional; Wood; Total: All Boiler Types	0.0373	0.0029	0.0372	0.0029
2103011000	Stationary Source Fuel Combustion; Commercial/Institutional; Kerosene; Total: All Combustor Types	0.0005	<0.0001	0.0005	<0.0001

2104004000	Stationary Source Fuel Combustion; Residential; Distillate Oil; Total: All Combustor Types	0.0002	<0.0001	0.0002	<0.0001
2104006000	Stationary Source Fuel Combustion; Residential; Natural Gas; Total: All Combustor Types	0.2233	0.0131	0.2233	0.0131
2104007000	Stationary Source Fuel Combustion; Residential; Liquified Petroleum Gas (LPG); Total: All Combustor Types	0.0065	0.0003	0.0065	0.0003
2104008610	Stationary Source Fuel Combustion; Residential; Wood; Hydronic heater: outdoor	0.0002	0.0068	0.0002	0.0069
2104008620	Stationary Source Fuel Combustion; Residential; Wood; Hydronic heater: indoor	0.0001	0.0043	0.0001	0.0044
2104008630	Stationary Source Fuel Combustion; Residential; Wood; Hydronic heater: pellet-fired	<0.0001	<0.0001	<0.0001	<0.0001
2104008700	Stationary Source Fuel Combustion; Residential; Wood; Outdoor wood burning device, NEC (fire-pits, chimneys, etc.)	0.0541	0.3934	0.0611	0.4438
2285002006	Mobile Sources; Railroad Equipment; Diesel; Line Haul Locomotives: Class I Operations	0.7936	0.0366	0.6131	0.0254
2285002007	Mobile Sources; Railroad Equipment; Diesel; Line Haul Locomotives: Class II / III Operations	0.0046	0.0002	0.0047	0.0002
2302002100	Industrial Processes; Food and Kindred Products: SIC 20; Commercial Cooking - Charbroiling; Conveyorized Charbroiling	--	0.0659	--	0.0781
2302002200	Industrial Processes; Food and Kindred Products: SIC 20; Commercial Cooking - Charbroiling; Under-fired Charbroiling	--	0.2243	--	0.2657
2302003000	Industrial Processes; Food and Kindred Products: SIC 20; Commercial Cooking - Frying; Deep Fat Frying	--	0.0472	--	0.0559
2302003100	Industrial Processes; Food and Kindred Products: SIC 20; Commercial Cooking - Frying; Flat Griddle Frying	--	0.0290	--	0.0344

2302003200	Industrial Processes; Food and Kindred Products: SIC 20; Commercial Cooking - Frying; Clamshell Griddle Frying	--	0.0015	--	0.0018
2401001000	Architectural Coatings	--	4.8222	--	5.3425
2401005000	Auto Refinishing: SIC 7532	--	0.4317	--	0.4822
2401008000	Traffic Markings	--	0.8299	--	0.7194
2401015000	Factory Finished Wood: SIC 2426 thru 242	--	0.0075	--	0.0088
2401020000	Wood Furniture: SIC 25	--	0.1210	--	0.1402
2401025000	Metal Furniture: SIC 25	--	0.1522	--	0.1763
2401030000	Paper: SIC 26	--	0.0008	--	0.0010
2401055000	Machinery and Equipment: SIC 35	--	0.0143	--	0.0165
2401065000	Electronic and Other Electrical: SIC 36 - 363	--	0.0458	--	0.0530
2401070000	Motor Vehicles: SIC 371	--	0.0161	--	0.0193
2401075000	Aircraft: SIC 372	--	0.0003	--	0.0004
2401090000	Surface Coating: Miscellaneous Manufacturing	--	0.1087	--	0.1266
2401100000	Industrial Maintenance Coatings	--	1.4639	--	1.7057
2401200000	Other Special Purpose Coatings	--	0.6791	--	0.7914
2415000000	Degreasing: All Processes/All Industries	--	0.6300	--	0.6256
2420000000	Dry Cleaning	--	0.0325	--	0.0326
2425000000	Graphic Arts	--	2.2024	--	2.5514
2460030999	C&C: Lighter Fluid, Fire Starter, Other Fuels	--	0.1308	--	0.1494
2460100000	C&C: Personal Care Products	--	8.7457	--	9.9864
2460200000	C&C: Household Products	--	6.6442	--	7.5867
2460400000	C&C: Automotive Aftermarket Products	--	0.8215	--	0.9380
2460500000	C&C: Coatings and Related Products	--	6.5223	--	7.4476
2460600000	C&C: Adhesives and Sealants	--	5.7803	--	6.6003
2460800000	C&C: FIFRA Related Products	--	0.4702	--	0.5369
2460900000	C&C: Miscellaneous Products (Not Otherwise Covered)	--	0.1100	--	0.1256
2461021000	Cutback Asphalt	--	0.8300	--	0.7767
2461022000	Emulsified Asphalt	--	3.3588	--	3.1428
2461850000	Pesticide Application: Agricultural	--	0.0037	--	0.0001

2501011011	Storage and Transport; Petroleum and Petroleum Product Storage; Residential Portable Gas Cans; Permeation	--	0.2020	--	0.2393
2501011012	Storage and Transport; Petroleum and Petroleum Product Storage; Residential Portable Gas Cans; Evaporation (includes Diurnal losses)	--	0.2267	--	0.2685
2501011013	Storage and Transport; Petroleum and Petroleum Product Storage; Residential Portable Gas Cans; Spillage During Transport	--	0.2808	--	0.3327
2501011014	Storage and Transport; Petroleum and Petroleum Product Storage; Residential Portable Gas Cans; Refilling at the Pump - Vapor Displacement	--	0.0577	--	0.0683
2501011015	Storage and Transport; Petroleum and Petroleum Product Storage; Residential Portable Gas Cans; Refilling at the Pump - Spillage	--	0.0083	--	0.0098
2501012011	Storage and Transport; Petroleum and Petroleum Product Storage; Commercial Portable Gas Cans; Permeation	--	0.0097	--	0.0115
2501012012	Storage and Transport; Petroleum and Petroleum Product Storage; Commercial Portable Gas Cans; Evaporation (includes Diurnal losses)	--	0.0080	--	0.0095
2501012013	Storage and Transport; Petroleum and Petroleum Product Storage; Commercial Portable Gas Cans; Spillage During Transport	--	0.5030	--	0.5960
2501012014	Storage and Transport; Petroleum and Petroleum Product Storage; Commercial Portable Gas Cans; Refilling at the Pump - Vapor Displacement	--	0.2181	--	0.2584
2501012015	Storage and Transport; Petroleum and Petroleum Product Storage; Commercial Portable Gas Cans; Refilling at the Pump - Spillage	--	0.0210	--	0.0249
2501050120	Storage and Transport; Petroleum and Petroleum Product Storage; Bulk Terminals: All Evaporative Losses; Gasoline	--	1.2891	--	1.0622

2501055120	Storage and Transport; Petroleum and Petroleum Product Storage; Bulk Plants: All Evaporative Losses; Gasoline	--	0.0003	--	0.0002
2501060051	Storage and Transport; Petroleum and Petroleum Product Storage; Gasoline Service Stations; Stage 1: Submerged Filling	--	5.5886	--	4.4738
2501060053	Storage and Transport; Petroleum and Petroleum Product Storage; Gasoline Service Stations; Stage 1: Balanced Submerged Filling	--	0.2157	--	0.1726
2501060201	Storage and Transport; Petroleum and Petroleum Product Storage; Gasoline Service Stations; Underground Tank: Breathing and Emptying	--	1.0519	--	0.8421
2501080050	Storage and Transport; Petroleum and Petroleum Product Storage; Airports : Aviation Gasoline; Stage 1: Total	--	0.3451	--	0.3320
2501080100	Storage and Transport; Petroleum and Petroleum Product Storage; Airports : Aviation Gasoline; Stage 2: Total	--	0.0004	--	0.0004
2505030120	Storage and Transport; Petroleum and Petroleum Product Transport; Truck; Gasoline	--	0.0706	--	0.0588
2505040120	Storage and Transport; Petroleum and Petroleum Product Transport; Pipeline; Gasoline	--	0.1018	--	0.0839
2610000500	Waste Disposal, Treatment, and Recovery; Open Burning; All Categories; Land Clearing Debris (use 28-10-005-000 for Logging Debris Burning)	0.1672	0.4723	0.1672	0.4723
2610030000	Waste Disposal, Treatment, and Recovery; Open Burning; Residential; Household Waste (use 26-10-000-xxx for Yard Wastes)	0.0188	0.0196	0.0188	0.0196
2630020000	Waste Disposal, Treatment, and Recovery; Wastewater Treatment; Public Owned; Total Processed	--	0.0757	--	0.0896
2680003000	Waste Disposal, Treatment, and Recovery; Composting; 100% Green Waste (e.g., residential or municipal yard wastes); All Processes	--	0.7757	--	0.7757

2805002000	Miscellaneous Area Sources; Agriculture Production - Livestock; Beef cattle production composite; Not Elsewhere Classified	--	0.0019	--	0.0019
2805007100	Miscellaneous Area Sources; Agriculture Production - Livestock; Poultry Waste; Poultry Production - Layers with Dry Manure Management Systems: Confinement	--	<0.0001	--	<0.0001
2805009100	Miscellaneous Area Sources; Agriculture Production - Livestock; Poultry production - broilers; Confinement	--	<0.0001	--	<0.0001
2805010100	Miscellaneous Area Sources; Agriculture Production - Livestock; Poultry production - turkeys; Confinement	--	<0.0001	--	<0.0001
2805018000	Miscellaneous Area Sources; Agriculture Production - Livestock; Dairy cattle composite; Not Elsewhere Classified	--	<0.0001	--	<0.0001
2805025000	Miscellaneous Area Sources; Agriculture Production - Livestock; Swine production composite; Not Elsewhere Classified (see also 28-05-039, -047, -053)	--	<0.0001	--	<0.0001
2805035000	Miscellaneous Area Sources; Agriculture Production - Livestock; Horses and Ponies Waste Emissions; Not Elsewhere Classified	--	0.0003	--	0.0003
2805040000	Miscellaneous Area Sources; Agriculture Production - Livestock; Sheep and Lambs Waste Emissions; Total	--	<0.0001	--	<0.0001
2805045000	Miscellaneous Area Sources; Agriculture Production - Livestock; Goats Waste Emissions; Not Elsewhere Classified	--	<0.0001	--	<0.0001
2810025000	Miscellaneous Area Sources; Other Combustion; Residential Grilling (see 23-02-002-xxx for Commercial); Total	0.0362	0.0960	0.0429	0.1138
2810060100	Miscellaneous Area Sources; Other Combustion; Cremation; Humans	0.0048	0.0004	0.0056	0.0005
2810060200	Miscellaneous Area Sources; Other Combustion; Cremation; Animals	<0.0001	<0.0001	<0.0001	<0.0001

Grand Total		**6.9445**	**57.7641**	**7.1522**	**61.7171**

Table A2. HA 212 ozone season weekday nonroad emissions by SCC.

SCC	SCC Description	2017 (TPD)		2026 (TPD)	
		NOX	VOC	NOX	VOC
2260001022	Mobile Sources; Off-highway Vehicle Gasoline; Recreational Equipment; 2-Stroke Other Recreational Equip.	0.0057	0.4635	0.0067	0.3685
2260001060	Mobile Sources; Off-highway Vehicle Gasoline; Recreational Equipment; 2-Stroke Specialty Vehicles/Carts	0.0047	0.0271	0.0046	0.0310
2260002022	Mobile Sources; Off-highway Vehicle Gasoline; Construction Equipment; 2-Stroke Construction Equipment	0.049	1.9073	0.0560	2.1973
2260003022	Mobile Sources; Off-highway Vehicle Gasoline; Industrial Equipment; 2-Stroke Industrial Equipment	<0.0001	0.0006	0.0000	0.0008
2260004020	Mobile Sources; Off-highway Vehicle Gasoline; Lawn and Garden Equipment; 2-Stroke Chain Saws < 6 HP (Residential)	0.0049	0.1831	0.0053	0.2005
2260004021	Mobile Sources; Off-highway Vehicle Gasoline; Lawn and Garden Equipment; 2-Stroke Chain Saws < 6 HP (Commercial)	0.0525	2.3689	0.0573	2.5877
2260004022	Mobile Sources; Off-highway Vehicle Gasoline; Lawn and Garden Equipment; 2-Stroke Mowers, Tractors, Turf Eqt (Commercial)	<0.0001	0.0006	0.0000	0.0006
2260004033	Mobile Sources; Off-highway Vehicle Gasoline; Lawn and Garden Equipment; 2-Stroke Lawn & Garden Eqt (Residential)	0.0185	0.5695	0.0202	0.6636
2260004044	Mobile Sources; Off-highway Vehicle Gasoline; Lawn and Garden Equipment; 2-Stroke Lawn & Garden Eqt (Commercial)	0.1494	3.9788	0.1631	4.3529

2260005022	Mobile Sources; Off-highway Vehicle Gasoline; Agricultural Equipment; 2-Stroke Agriculture Equipment	<0.0001	<0.0001	0.0000	0.0000
2260006022	Mobile Sources; Off-highway Vehicle Gasoline; Commercial Equipment; 2-Stroke Commercial Equipment	0.0039	0.1111	0.0049	0.1402
2265001022	Mobile Sources; Off-highway Vehicle Gasoline; Recreational Equipment; 4-Stroke Other Recreational Equip.	0.017	0.2305	0.0172	0.2437
2265001050	Mobile Sources; Off-highway Vehicle Gasoline; Recreational Equipment; 4-Stroke Golf Carts	0.0292	0.105	0.0324	0.1175
2265001060	Mobile Sources; Off-highway Vehicle Gasoline; Recreational Equipment; 4-Stroke Specialty Vehicles/Carts	0.0062	0.0287	0.0044	0.0209
2265002022	Mobile Sources; Off-highway Vehicle Gasoline; Construction Equipment; 4-Stroke Construction Equipment	0.2899	1.1038	0.2781	1.2427
2265003022	Mobile Sources; Off-highway Vehicle Gasoline; Industrial Equipment; 4-Stroke Industrial Equipment	0.0147	0.0237	0.0170	0.0311
2265003060	Mobile Sources; Off-highway Vehicle Gasoline; Industrial Equipment; 4-Stroke AC\Refrigeration	0.0002	0.0008	0.0003	0.0012
2265004022	Mobile Sources; Off-highway Vehicle Gasoline; Lawn and Garden Equipment; 4-Stroke Mowers, Tractors, Turf Eqt (Commercial)	0.8958	3.3743	0.9860	3.7585
2265004033	Mobile Sources; Off-highway Vehicle Gasoline; Lawn and Garden Equipment; 4-Stroke Lawn & Garden Eqt (Residential)	0.2817	2.5117	0.2760	2.7444
2265004044	Mobile Sources; Off-highway Vehicle Gasoline; Lawn and Garden Equipment; 4-Stroke Lawn & Garden Eqt (Commercial)	0.4767	2.8519	0.4828	3.0363

2265005022	Mobile Sources; Off-highway Vehicle Gasoline; Agricultural Equipment; 4-Stroke Agriculture Equipment	<0.0001	<0.0001	0.0000	0.0000
2265006022	Mobile Sources; Off-highway Vehicle Gasoline; Commercial Equipment; 4-Stroke Commercial Equipment	0.1635	0.9646	0.1855	1.2445
2267001060	Mobile Sources; Off-highway Vehicle LPG; Recreational Equipment; LPG Specialty Vehicles/Carts	0.0014	0.0003	0.0008	0.0002
2267002022	Mobile Sources; Off-highway Vehicle LPG; Construction Equipment; LPG Construction Equipment	0.0846	0.0169	0.0461	0.0069
2267003022	Mobile Sources; Off-highway Vehicle LPG; Industrial Equipment; LPG Industrial Equipment	0.1184	0.0179	0.1344	0.0158
2267004044	Mobile Sources; Off-highway Vehicle LPG; Lawn and Garden Equipment; LPG Lawn & Garden Eqt (Commercial)	0.016	0.0024	0.0142	0.0017
2267005022	Mobile Sources; Off-highway Vehicle LPG; Agricultural Equipment; LPG Agriculture Equipment	<0.0001	<0.0001	0.0000	0.0000
2267006022	Mobile Sources; Off-highway Vehicle LPG; Commercial Equipment; LPG Commercial Equipment	0.0524	0.0086	0.0295	0.0043
2268002022	Mobile Sources; Off-highway Vehicle CNG; Construction Equipment; CNG Construction Equipment	0.0005	0.0004	0.0002	0.0001
2268003022	Mobile Sources; Off-highway Vehicle CNG; Industrial Equipment; CNG Industrial Equipment	0.0092	0.0049	0.0108	0.0046
2268003060	Mobile Sources; Off-highway Vehicle CNG; Industrial Equipment; CNG AC\Refrigeration	0.0001	<0.0001	0.0001	0.0000
2268005022	Mobile Sources; Off-highway Vehicle CNG; Agricultural Equipment; CNG Agriculture Equipment	<0.0001	<0.0001	0.0000	0.0000

2268006022	Mobile Sources; Off-highway Vehicle CNG; Commercial Equipment; CNG Commercial Equipment	0.0232	0.0128	0.0181	0.0093
2270001060	Mobile Sources; Off-highway Vehicle Diesel; Recreational Equipment; Specialty Vehicles/Carts	0.0157	0.0036	0.0106	0.0018
2270002022	Mobile Sources; Off-highway Vehicle Diesel; Construction Equipment; Diesel Construction Equipment	31.6988	2.9074	14.3430	1.0884
2270003022	Mobile Sources; Off-highway Vehicle Diesel; Industrial Equipment; Diesel Industrial Equipment	0.1188	0.0079	0.0718	0.0029
2270003060	Mobile Sources; Off-highway Vehicle Diesel; Industrial Equipment; AC\Refrigeration	0.3474	0.0202	0.4231	0.0135
2270004022	Mobile Sources; Off-highway Vehicle Diesel; Lawn and Garden Equipment; Diesel Mowers, Tractors, Turf Eqt (Commercial)	0.1441	0.0137	0.1230	0.0099
2270004044	Mobile Sources; Off-highway Vehicle Diesel; Lawn and Garden Equipment; Diesel Lawn & Garden Eqt (Commercial)	1.302	0.1214	0.8370	0.0623
2270005022	Mobile Sources; Off-highway Vehicle Diesel; Agricultural Equipment; Diesel Agriculture Equipment	0.0005	<0.0001	0.0002	0.0000
2270006022	Mobile Sources; Off-highway Vehicle Diesel; Commercial Equipment; Diesel Commercial Equipment	0.5754	0.0664	0.4288	0.0355
2282005022	Mobile Sources; Pleasure Craft; Gasoline; 2-Stroke Pleasure Craft	0.0022	0.0157	0.0024	0.0070
2282010005	Mobile Sources; Pleasure Craft; Gasoline 4-Stroke; Inboard/Sterndrive	0.0015	0.0024	0.0007	0.0016
2282020022	Mobile Sources; Pleasure Craft; Diesel; Diesel Pleasure Craft	0.0014	0.0001	0.0012	0.0001
2285002015	Mobile Sources; Railroad Equipment; Diesel; Railway Maintenance	0.0059	0.001	0.0034	0.0005

2285004015	Mobile Sources; Railroad Equipment; Gasoline, 4-Stroke; Railway Maintenance	0.0001	0.0004	0.0001	0.0005
2285006015	Mobile Sources; Railroad Equipment; LPG; Railway Maintenance	<0.0001	<0.0001	0.0000	0.0000
Grand Total		**36.9831**	**24.0299**	**19.0976**	**24.2507**

Appendix B Clark County Nonattainment Area Unit-level Point Source Emissions

Appendix B Clark County Nonattainment Area Unit-level Point Source Emissions

Table B1. HA 212 unit-level point source NOx emissions for 2017 and 2026.

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2026 TPY	2026 TPD	2026 summer TPD	2016-2026 Per year Growth Factor	Source
Certain Teed Gypsum	Generator	4	4-L4	20200401	27	0.36	0.001	0.001	0.3620	0.0010	0.0011	0.0000	2016 v.1
Certain Teed Gypsum	Generator	4	B8	20200401	27	0.92	0.003	0.003	0.9240	0.0025	0.0027	0.0000	2016 v.1
Certain Teed Gypsum	Continuous Calciner	4	4-G1	30501511	25	5.02	0.014	0.014	5.5622	0.0152	0.0152	0.0120	2016 v.1
Certain Teed Gypsum	Impact Mill	4	4-E11	30501513	25	3.82	0.010	0.010	4.2326	0.0116	0.0116	0.0120	2016 v.1
Certain Teed Gypsum	Dryer	4	4-J3	30501520	25	1.31	0.004	0.004	1.4515	0.0040	0.0040	0.0120	2016 v.1
NV Energy (Clark Station)	Turbine	7	4	20100201	25	8.33	0.023	0.023	8.3550	0.0229	0.0229	0.0004	2016 v.1
NV Energy (Clark Station)	Turbine	7	5	20100201	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	6	20100201	25	2.80	0.008	0.008	3.2057	0.0088	0.0088	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	7	20100201	25	0.51	0.001	0.001	0.5839	0.0016	0.0016	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	8	20100201	25	0.75	0.002	0.002	0.8587	0.0024	0.0024	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	27	20100201	25	2.43	0.007	0.007	2.7821	0.0076	0.0076	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	28	20100201	25	3.32	0.009	0.009	3.8011	0.0104	0.0104	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	29	20100201	25	5.63	0.015	0.015	6.4458	0.0177	0.0177	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	30	20100201	25	3.90	0.011	0.011	4.4651	0.0122	0.0122	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	31	20100201	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	32	20100201	25	3.13	0.009	0.009	3.5835	0.0098	0.0098	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	33	20100201	25	3.05	0.008	0.008	3.4919	0.0096	0.0096	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	34	20100201	25	5.14	0.014	0.014	5.8848	0.0161	0.0161	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	35	20100201	25	0.70	0.002	0.002	0.8014	0.0022	0.0022	0.0161	2016 v.1

NV Energy (Clark Station)	Turbine	7	36	20100201	25	2.02	0.006	0.006	2.3127	0.0063	0.0063	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	37	20100201	25	0.07	0.000	0.000	0.0801	0.0002	0.0002	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	38	20100201	25	4.96	0.014	0.014	5.6787	0.0156	0.0156	0.0161	2016 v.1
NV Energy (Clark Station)	Generator	7	21	20200102	25	0.45	0.001	0.001	0.5152	0.0014	0.0014	0.0161	2016 v.1
NV Energy (Clark Station)	Generator	7	22	20200102	25	1.76	0.005	0.005	2.0150	0.0055	0.0055	0.0161	2016 v.1
NV Energy (Clark Station)	Generator	7	45	20200102	25	19.90	0.055	0.055	22.7835	0.0624	0.0624	0.0161	2016 v.1
NV Energy (Clark Station)	Generator	7	46	20200102	25	2.85	0.008	0.008	3.2630	0.0089	0.0089	0.0161	2016 v.1
Olin Chlor Alkali Products	Generator	9	1	20200102	25	7.53	0.021	0.021	8.6211	0.0236	0.0236	0.0161	2016 v.1
Viawest Lone Mountain Data Center	Generator	12	2	20300101	25	4.52	0.012	0.012	5.1749	0.0142	0.0142	0.0161	2016 v.1
Wells Cargo	Asphalt Oil Heater	12	1	30500206	25	0.90	0.002	0.002	1.0304	0.0028	0.0028	0.0161	2016 v.1
Kinder Morgan	Diesel Pump	13	D02	20200102	25	4.18	0.011	0.011	4.7857	0.0131	0.0131	0.0161	2016 v.1
Kinder Morgan	Flare Processing	13	B10	30600904	25	1.26	0.003	0.003	1.4426	0.0040	0.0040	0.0161	2016 v.1
Kinder Morgan	Thermal Oxidizer	13	SR04	50410312	25	0.89	0.002	0.002	1.0190	0.0028	0.0028	0.0161	2016 v.1
Titanium Metals Corp.	Steam Generator	19	B09	10200602	25	1.42	0.004	0.004	1.6258	0.0045	0.0045	0.0161	2016 v.1
Titanium Metals Corp.	CO Burner/Boiler	19	B06	10201402	25	0.67	0.002	0.002	0.7671	0.0021	0.0021	0.0161	2016 v.1
Titanium Metals Corp.	Hot Oil Heater	19	C05	30301201	25	17.45	0.048	0.048	19.9785	0.0547	0.0547	0.0161	2016 v.1
Titanium Metals Corp.	Generator	19	E03	30301202	25	2.13	0.006	0.006	2.4386	0.0067	0.0067	0.0161	2016 v.1
Titanium Metals Corp.	Fugitives	19	A01	30301299	25	0.10	0.000	0.000	0.1145	0.0003	0.0003	0.0161	2016 v.1
Titanium Metals Corp.	Thermal Oxidizer	19	B10	30301299	25	40.26	0.110	0.110	46.0937	0.1263	0.1263	0.0161	2016 v.1
Northwind Alladin	Boiler	26	1	10300603	25	7.81	0.021	0.021	8.9417	0.0245	0.0245	0.0161	2016 v.1
Circus Circus Hotel and Casino	Boiler	47	1	10300603	25	0.83	0.002	0.002	0.9503	0.0026	0.0026	0.0161	2016 v.1
CCWRD Flamingo Center	Boiler	54	1	10300603	25	2.07	0.006	0.006	2.3699	0.0065	0.0065	0.0161	2016 v.1
BKEP Materials	Boiler	67	1	10300603	25	7.45	0.020	0.020	8.5295	0.0234	0.0234	0.0161	2016 v.1
Las Vegas Paving - Blue Diamond	Drum Mixer	70	B12	30500257	25	8.84	0.024	0.024	10.1209	0.0277	0.0277	0.0161	2016 v.1

Golden Nugget Hotel and Casino	Boiler	81	1	10300603	25	2.94	0.008	0.008	3.3660	0.0092	0.0092	0.0161	2016 v.1
Horseshoe Club	Boiler	85	1	10300603	25	0.91	0.002	0.002	1.0419	0.0029	0.0029	0.0161	2016 v.1
Tronox	Boiler	95	A10	10300602	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0161	2016 v.1
Tronox	Boiler	95	A15	10300602	25	0.06	0.000	0.000	0.0687	0.0002	0.0002	0.0161	2016 v.1
Treasure Island	Boiler	95	A01	10300603	25	22.77	0.062	0.062	26.0694	0.0714	0.0714	0.0161	2016 v.1
Tronox	Generator	95	A02	20300101	25	4.24	0.012	0.012	4.8544	0.0133	0.0133	0.0161	2016 v.1
Tronox	Generator	95	A03	20300101	25	4.12	0.011	0.011	4.7170	0.0129	0.0129	0.0161	2016 v.1
Tronox	Generator	95	A04	20300101	25	6.00	0.016	0.016	6.8694	0.0188	0.0188	0.0161	2016 v.1
Tronox	Generator	95	A07	20300101	25	1.61	0.004	0.004	1.8433	0.0051	0.0051	0.0161	2016 v.1
Tronox	Chem. Manufacturing	95	A05	30107002	25	1.58	0.004	0.004	1.8089	0.0050	0.0050	0.0161	2016 v.1
Westgate Las Vegas	Generator	101	B	20100102	25	2.16	0.006	0.006	2.4730	0.0068	0.0068	0.0161	2016 v.1
West Rock	Printing Press	101	G	40500501	25	2.79	0.008	0.008	3.1943	0.0088	0.0088	0.0161	2016 v.1
Las Vegas Paving - 5th Street	Fire Pump	104	H01	20200102	25	4.34	0.012	0.012	4.9689	0.0136	0.0136	0.0161	2016 v.1
Las Vegas Paving - 5th Street	Drum Mixer	104	E01	30500205	25	1.27	0.003	0.003	1.4540	0.0040	0.0040	0.0161	2016 v.1
Las Vegas Paving - 5th Street	Oil Heater	104	E02	30500206	25	5.36	0.015	0.015	6.1367	0.0168	0.0168	0.0161	2016 v.1
Las Vegas Paving - 5th Street	Drum Dryer	104	E03	39001089	25	13.75	0.038	0.038	15.7424	0.0431	0.0431	0.0161	2016 v.1
Las Vegas Paving - Lone Mountain	Generator	105	C	20200102	25	3.10	0.008	0.008	3.5492	0.0097	0.0097	0.0161	2016 v.1
Las Vegas Paving - Lone Mountain	Drum Dryer	105	B012	30500205	25	33.23	0.091	0.091	33.2300	0.0910	0.0910	0.0000	2016 v.1
Las Vegas Paving - Lone Mountain	Oil Heater	105	B011	30500209	25	4.01	0.011	0.011	4.0100	0.0110	0.0110	0.0000	2016 v.1
McCarran International Airport	Boiler	108	A	10300602	25	0.38	0.001	0.001	0.3800	0.0010	0.0010	0.0000	2016 v.1
McCarran International Airport	Generator	108	E	20200102	25	0.10	0.000	0.000	0.1000	0.0003	0.0003	0.0000	2016 v.1
Nellis AFB	Nat gas boilers	114	RB-C	10300602	51	0.04	0.000	0.000	0.0400	0.0001	0.0002	0.0000	2016 v.1
Nellis AFB	Internal Combustion	114	G	20300301	51	0.08	0.000	0.000	0.0800	0.0002	0.0004	0.0000	2016 v.1
Nellis AFB	Hush House	114	N	20400110	25	0.33	0.001	0.001	0.3300	0.0009	0.0009	0.0000	2016 v.1
Nellis AFB	Drum Mixer	114	A047	30500205	25	0.03	0.000	0.000	0.0300	0.0001	0.0001	0.0000	2016 v.1
SLS Las Vegas	Boiler	133	A	10300602	25	0.06	0.000	0.000	0.0600	0.0002	0.0002	0.0000	2016 v.1

SLS Las Vegas	Generator	133	B	20300101	27	0.06	0.000	0.000	0.0610	0.0002	0.0002	0.0000	2016 v.1
University Medical Center	Boiler	142	B	10300603	27	0.08	0.000	0.000	0.0790	0.0002	0.0002	0.0000	2016 v.1
Univeral Urethane	Spray painting booths	142	A	40202201	25	0.27	0.001	0.001	0.2700	0.0007	0.0007	0.0000	2016 v.1
Las Vegas Paving	Drum Mixer	186	B013	30500205	25	4.90	0.013	0.013	4.9000	0.0134	0.0134	0.0000	2016 v.1
Las Vegas Paving	Oil Heater	186	B023	30500208	51	5.33	0.015	0.030	7.0425	0.0193	0.0394	0.0357	2016 v.1
Caesars Consolidated	Boiler	257	1	10300603	51	2.00	0.005	0.011	2.6426	0.0072	0.0148	0.0357	2016 v.1
Mirage/Treasure Island	Boiler	282	1	10300603	51	2.75	0.008	0.015	3.6336	0.0100	0.0203	0.0357	2016 v.1
Brady Linen Services	Dryer	322	1	30504033	51	2.72	0.007	0.015	3.5939	0.0098	0.0201	0.0357	2016 v.1
Catalina Plastic and Coating	Plastics	323	1	40201399	51	2.86	0.008	0.016	3.7789	0.0104	0.0211	0.0357	2016 v.1
Las Vegas Cogeneration	Generator	329	10	20100102	25	6.21	0.017	0.017	8.2053	0.0225	0.0225	0.0357	2016 v.1
Las Vegas Cogeneration	Generator	329	11	20100102	37	6.73	0.018	0.027	7.2224	0.0198	0.0293	0.0081	ERTAC
Las Vegas Cogeneration	Turbine	329	1	20100201	37	5.10	0.014	0.021	5.3284	0.0146	0.0216	0.0050	ERTAC
Las Vegas Cogeneration	Turbine	329	3	20100201	37	4.06	0.011	0.016	4.3723	0.0120	0.0177	0.0085	ERTAC
Las Vegas Cogeneration	Turbine	329	4	20100201	27	8.70	0.024	0.026	11.495 3	0.0315	0.0340	0.0357	2016 v.1
Las Vegas Cogeneration	Turbine	329	5	20100201	27	10.20	0.028	0.030	13.477 3	0.0369	0.0399	0.0357	2016 v.1 2023; IPM 2016-2030
Las Vegas Cogeneration	Turbine	329	6	20100201	27	10.40	0.028	0.031	13.741 5	0.0376	0.0407	0.0357	2016 v.1 2023; IPM 2016-2030
Boral Roofing	Curing Tunnel	346	B18	30500850	27	7.90	0.022	0.023	10.438 3	0.0286	0.0309	0.0357	2016 v.1 2023; IPM 2016-2030
Aggregate Industries	Boiler	372	6	10300602	27	11.20	0.031	0.033	14.798 6	0.0405	0.0438	0.0357	2016 v.1 2023; IPM 2016-2030
Aggregate Industries	Boiler	372	10	10300602	27	2.95	0.008	0.009	3.6875	0.0101	0.0109	0.0278	ERTAC
Aggregate Industries	Generator	372	1	20100102	27	4.68	0.013	0.014	4.6800	0.0128	0.0138	0.0000	ERTAC
Aggregate Industries	Generator	372	9	20100102	27	3.24	0.009	0.010	3.8739	0.0106	0.0115	0.0217	ERTAC
Aggregate Industries	Mineral Products	372	2	30500208	27	5.33	0.015	0.016	6.4721	0.0177	0.0192	0.0238	ERTAC
Aggregate Industries	Mineral Products	372	5	30500208	27	3.39	0.009	0.010	3.8322	0.0105	0.0113	0.0145	ERTAC

Aggregate Industries	Mineral Products	372	3	30500242	27	3.70	0.010	0.011	4.5763	0.0125	0.0135	0.0263	ERTAC
Saguaro Power Company	Boiler	393	5	10100601	27	3.22	0.009	0.010	3.5127	0.0096	0.0104	0.0101	ERTAC
Saguaro Power Company	Boiler	393	6	10100602	27	4.25	0.012	0.013	5.0227	0.0138	0.0149	0.0202	ERTAC
Saguaro Power Company	Starter	393	3	20100102	27	3.13	0.009	0.009	3.5383	0.0097	0.0105	0.0145	ERTAC
Saguaro Power Company	Starter	393	4	20100102	27	4.19	0.011	0.012	5.2830	0.0145	0.0156	0.0290	ERTAC
Saguaro Power Company	Turbine	393	1	20100201	27	3.08	0.008	0.009	3.6235	0.0099	0.0107	0.0196	ERTAC
Saguaro Power Company	Turbine	393	2	20100201	27	3.25	0.009	0.010	3.9464	0.0108	0.0117	0.0238	ERTAC
City of Las Vegas WPCF	Generator	402	2	20200102	27	51.92	0.142	0.154	68.6072	0.1880	0.2030	0.0357	2016 v.1*
City of Las Vegas WPCF	Generator	402	3	20200202	27	49.45	0.135	0.146	65.3436	0.1790	0.1933	0.0357	2016 v.1*
City of Las Vegas WPCF	Waste Flare	402	5	50100789	25	0.02	0.000	0.000	0.0243	0.0001	0.0001	0.0238	2016 v.1
City of Las Vegas WPCF	Blower Engines	402	6	50100799	25	1.01	0.003	0.003	1.2263	0.0034	0.0034	0.0238	2016 v.1
City of Las Vegas WPCF	Boilers	402	7	50100799	25	0.07	0.000	0.000	0.0850	0.0002	0.0002	0.0238	2016 v.1
Nikkiso Cryo	Generator	404	1	20200102	25	7.70	0.021	0.021	9.3493	0.0256	0.0256	0.0238	2016 v.1
Nevada Sun Peak Partnerships	Turbine	423	1	20100201	25	0.06	0.000	0.000	0.0729	0.0002	0.0002	0.0238	2016 v.1
Nevada Sun Peak Partnerships	Turbine	423	2	20100201	25	44.93	0.123	0.123	54.5540	0.1495	0.1495	0.0238	2016 v.1
Nevada Sun Peak Partnerships	Turbine	423	3	20100201	25	4.69	0.013	0.013	5.6946	0.0156	0.0156	0.0238	2016 v.1
Hard Rock Hotel and Casino	Boiler	510	A	10300603	25	8.90	0.024	0.024	10.8064	0.0296	0.0296	0.0238	2016 v.1
Hard Rock Hotel and Casino	Generator	510	B	20300101	27	0.01	0.000	0.000	0.0121	0.0000	0.0000	0.0238	2016 v.1
Texas Station Casino	Boiler	531	A	10300603	27	0.01	0.000	0.000	0.0121	0.0000	0.0000	0.0238	2016 v.1
Texas Station Casino	Generator	531	B	20300101	27	0.01	0.000	0.000	0.0121	0.0000	0.0000	0.0238	2016 v.1
Citibank The Lakes	Generator	546	A	20300101	27	0.01	0.000	0.000	0.0121	0.0000	0.0000	0.0238	2016 v.1
Rio All Suites Hotel and Casino	Boiler	555	A	10300603	25	0.86	0.002	0.002	1.0442	0.0029	0.0029	0.0238	2016 v.1
Rio All Suites Hotel and Casino	Generator	555	C	20300101	25	0.01	0.000	0.000	0.0121	0.0000	0.0000	0.0238	2016 v.1
Kurt Segler Water Reclamation	Generator	558	B	20200102	25	0.10	0.000	0.000	0.0932	0.0003	0.0003	-0.0076	2016 v.1

Kurt Segler Water Reclamation	Waste water treatment	558	B01	50100765	25	1.67	0.005	0.005	1.9255	0.0053	0.0053	0.0170	2016 v.1
Stratosphere Hotel and Casino	Boiler	564	A	10300603	25	0.03	0.000	0.000	0.0346	0.0001	0.0001	0.0170	2016 v.1
Stratosphere Hotel and Casino	Generator	564	B	20300101	25	0.71	0.002	0.002	0.8499	0.0023	0.0023	0.0219	2016 v.1
Aggregate Industries - Gowan	Drum Mixer	587	A08	30500205	25	1.05	0.003	0.003	1.2570	0.0034	0.0034	0.0219	2016 v.1
Aggregate Industries - Gowan	Asphalt Oil Heater	587	E	30500208	25	0.09	0.000	0.000	0.1077	0.0003	0.0003	0.0219	2016 v.1
Aggregate Industries - Gowan	Asphalt Silos	587	A12	30500212	25	73.04	0.200	0.200	87.4362	0.2396	0.2396	0.0219	2016 v.1
Las Vegas Review Journal	Generator	588	D	20300101	25	0.98	0.003	0.003	1.1732	0.0032	0.0032	0.0219	2016 v.1
Las Vegas Review Journal	Parts Washer	588	B	40500417	25	0.47	0.001	0.001	0.5626	0.0015	0.0015	0.0219	2016 v.1
Berry Plastics Corporation	Generator	597	F01	20300101	25	0.52	0.001	0.001	0.6225	0.0017	0.0017	0.0219	2016 v.1
Berry Plastics Corporation	Offset Printing	597	E01	40500802	25	2.05	0.006	0.006	2.4541	0.0067	0.0067	0.0219	2016 v.1
Palace Station Hotel and Casino	Boiler	605	A	10300603	25	0.28	0.001	0.001	0.3352	0.0009	0.0009	0.0219	2016 v.1
Palace Station Hotel and Casino	Generator	605	B	20300101	25	1.09	0.003	0.003	1.3048	0.0036	0.0036	0.0219	2016 v.1
Gold Coast Hotel and Casino	Boiler	606	A	10300603	25	2.47	0.007	0.007	2.9568	0.0081	0.0081	0.0219	2016 v.1
Gold Coast Hotel and Casino	Generator	606	B	20300101	25	0.21	0.001	0.001	0.2514	0.0007	0.0007	0.0219	2016 v.1
Sams Town Hotel and Casino	Boiler	616	A	10300603	25	11.35	0.031	0.031	13.5871	0.0372	0.0372	0.0219	2016 v.1
Sams Town Hotel and Casino	Generator	616	B	20300101	25	0.11	0.000	0.000	0.1317	0.0004	0.0004	0.0219	2016 v.1
Santa Fe Station	Boiler	621	A	10300603	25	1.07	0.003	0.003	1.2809	0.0035	0.0035	0.0219	2016 v.1
Santa Fe Station	Generator	621	B	20300101	25	0.45	0.001	0.001	0.5387	0.0015	0.0015	0.0219	2016 v.1
University Medical Center	Generator	634	B	20300101	25	0.81	0.002	0.002	0.9697	0.0027	0.0027	0.0219	2016 v.1
University of Nevada, Las Vegas	Generator	634	A	20300101	25	0.40	0.001	0.001	0.4788	0.0013	0.0013	0.0219	2016 v.1
Orleans Hotel and Casino	Boiler	641	A	10300603	25	1.35	0.004	0.004	1.6161	0.0044	0.0044	0.0219	2016 v.1
Orleans Hotel and Casino	Generator	641	B	20300101	25	0.77	0.002	0.002	0.9218	0.0025	0.0025	0.0219	2016 v.1
University of Nevada, Las Vegas	Boiler	697	C	10300603	25	18.60	0.051	0.051	22.2661	0.0610	0.0610	0.0219	2016 v.1

Venetian Hotel and Casino	Generator	697	B	20300101	25	1.26	0.003	0.003	1.5083	0.0041	0.0041	0.0219	2016 v.1
Venetian Hotel and Casino	Boiler	726	A	10300603	25	0.58	0.002	0.002	0.6943	0.0019	0.0019	0.0219	2016 v.1
Nevada Color Litho	Printing Press	754	A05	40500433	25	0.54	0.001	0.001	0.6464	0.0018	0.0018	0.0219	2016 v.1
JW Marriott Las Vegas	Boiler	755	A	10300603	25	0.38	0.001	0.001	0.4549	0.0012	0.0012	0.0219	2016 v.1
JW Marriott Las Vegas	Generator	755	B	20300101	25	1.73	0.005	0.005	2.0710	0.0057	0.0057	0.0219	2016 v.1
Suncoast Hotel and Casino	Boiler	775	A	10300603	25	0.23	0.001	0.001	0.2753	0.0008	0.0008	0.0219	2016 v.1
Suncoast Hotel and Casino	Generator	775	B	20300101	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0219	2016 v.1
Veterans Administration	Generator	777	A	20300101	25	1.64	0.004	0.004	1.9632	0.0054	0.0054	0.0219	2016 v.1
Cancun Resort	Boiler	788	A	10300603	25	0.03	0.000	0.000	0.0359	0.0001	0.0001	0.0219	2016 v.1
Cancun Resort	Generator	788	B	20300101	25	0.74	0.002	0.002	0.8859	0.0024	0.0024	0.0219	2016 v.1
Clearwater Paper	Boiler	807	A10	10200602	25	0.55	0.002	0.002	0.6584	0.0018	0.0018	0.0219	2016 v.1
Clearwater Paper	Air heaters	807	A08	30790003	25	0.29	0.001	0.001	0.3472	0.0010	0.0010	0.0219	2016 v.1
Clearwater Paper	Paper process fugitives	807	F	30799998	25	0.79	0.002	0.002	0.9457	0.0026	0.0026	0.0219	2016 v.1
MGM Grand/New York New York	Boiler	825	A	10300603	25	1.24	0.003	0.003	1.4844	0.0041	0.0041	0.0219	2016 v.1
MGM Grand/New York New York	Turbine	825	E	20100201	25	5.23	0.014	0.014	6.2608	0.0172	0.0172	0.0219	2016 v.1
MGM Grand/New York New York	Generator	825	B	20300101	25	1.06	0.003	0.003	1.2689	0.0035	0.0035	0.0219	2016 v.1
MGM Grand/New York New York	Paint booth	825	C	40201101	25	0.35	0.001	0.001	0.4190	0.0011	0.0011	0.0219	2016 v.1
MGM Grand/New York New York	Tank	825	D	40600401	25	1.83	0.005	0.005	2.1907	0.0060	0.0060	0.0219	2016 v.1
UNEV Pipeline	Generator	859	A	20200102	25	3.34	0.009	0.009	3.9983	0.0110	0.0110	0.0219	2016 v.1
Univeral Urethane	Molding machines	859	B	30800802	25	0.47	0.001	0.001	0.5626	0.0015	0.0015	0.0219	2016 v.1
Sunset Station	Boiler	869	A	10300603	25	0.32	0.001	0.001	0.3831	0.0010	0.0010	0.0219	2016 v.1
Sunset Station	Generator	869	B	20300101	25	0.04	0.000	0.000	0.0479	0.0001	0.0001	0.0219	2016 v.1
Wynn Las Vegas	Boiler	974	A	10300602	25	0.10	0.000	0.000	0.1197	0.0003	0.0003	0.0219	2016 v.1
Wells Cargo Lone Mountain	Engines	1055	A	20300101	25	0.10	0.000	0.000	0.1197	0.0003	0.0003	0.0219	2016 v.1
Republic Services Transfer Station	Boiler	1087	B	10300603	25	0.37	0.001	0.001	0.4429	0.0012	0.0012	0.0219	2016 v.1

Republic Services Transfer Station	Generator	1087	G	20300101	25	2.76	0.008	0.008	3.3040	0.0091	0.0091	0.0219	2016 v.1
Las Vegas Color Graphics	Printing Press	1149	A	40500411	25	2.21	0.006	0.006	2.6456	0.0072	0.0072	0.0219	2016 v.1
St Rose Dominican Siena	Boiler	1500	A	10300603	25	4.09	0.011	0.011	4.8961	0.0134	0.0134	0.0219	2016 v.1
St Rose Dominican Siena	Generator	1500	B	20300101	25	0.96	0.003	0.003	1.1492	0.0031	0.0031	0.0219	2016 v.1
Green Valley Ranch Resort	Boiler	1501	A	10300603	25	2.86	0.008	0.008	3.4237	0.0094	0.0094	0.0219	2016 v.1
Green Valley Ranch Resort	Generator	1501	B	20300101	25	1.11	0.003	0.003	1.3288	0.0036	0.0036	0.0219	2016 v.1
Palms Casino Resort	Boiler	1522	A	10300603	25	0.40	0.001	0.001	0.4788	0.0013	0.0013	0.0219	2016 v.1
Palms Casino Resort	Generator	1522	B	20300101	25	39.42	0.108	0.108	47.1897	0.1293	0.1293	0.0219	2016 v.1
Boulder Station Hotel and Casino	Boiler	1524	A	10300603	25	2.59	0.007	0.007	3.1005	0.0085	0.0085	0.0219	2016 v.1
Boulder Station Hotel and Casino	Generator	1524	B	20300101	25	4.77	0.013	0.013	4.8602	0.0133	0.0133	0.0021	2016 v.1
Mountain View Hospital	Boiler	1569	A	10300603	25	5.92	0.016	0.016	7.4065	0.0203	0.0203	0.0279	2016 v.1
Mountain View Hospital	Generator	1569	B	20300101	25	9.18	0.025	0.025	10.1880	0.0279	0.0279	0.0122	2016 v.1
Lasfuel McCarran Tank Farm	Generator	1589	C	20300101	25	1.20	0.003	0.003	1.2000	0.0033	0.0033	0.0000	2016 v.1
Lasfuel McCarran Tank Farm	Thermal Oxidizer	1589	B06	40400153	25	0.06	0.000	0.000	0.0600	0.0002	0.0002	0.0000	default value
Wynn Las Vegas	Generator	1624	A	20100102	25	1.07	0.003	0.003	1.0700	0.0029	0.0029	0.0000	default value
World Market Center	Generator	1624	F	20300101	25	0.01	0.000	0.000	0.0050	0.0000	0.0000	0.0000	2016 v.1
Wynn Las Vegas	Dry Cleaning	1624	R	40100103	25	12.41	0.034	0.034	12.4050	0.0340	0.0340	0.0000	2016 v.1
Wynn Las Vegas	AST	1624	C	40600306	25	0.10	0.000	0.000	0.1000	0.0003	0.0003	0.0000	2016 v.1
North Las Vegas Airport	Generator	9596	C	20100102	25	5.12	0.014	0.014	5.1200	0.0140	0.0140	0.0000	2016 v.1
Henderson Executive Airport	Generator	9603	B	20100102	25	1.63	0.004	0.004	1.6300	0.0045	0.0045	0.0000	2016 v.1
Brady Linen Services	Boiler	10201	B	10200602	25	4.15	0.011	0.011	4.1500	0.0114	0.0114	0.0000	2016 v.1
Brady Linen Services	Dryer	10201	D	41000130	25	5.71	0.016	0.016	5.7100	0.0156	0.0156	0.0000	2016 v.1
Republic Services (Sunrise)	Flare	15033	1	50300601	25	0.23	0.001	0.001	0.2300	0.0006	0.0006	0.0000	2016 v.1
CPP Acquisition	Dryer	15193	D	40500101	25	0.59	0.002	0.002	0.5900	0.0016	0.0016	0.0000	2016 v.1

CPP Acquisition	Printer	15193	P	40500401	25	0.62	0.002	0.002	0.6200	0.0017	0.0017	0.0000	2016 v.1
McCarran Rent a Car Center	Boiler	15409	A	10300603	25	0.23	0.001	0.001	0.2300	0.0006	0.0006	0.0000	2016 v.1
McCarran Rent a Car Center	Generator	15409	B	20100102	25	0.01	0.000	0.000	0.0100	0.0000	0.0000	0.0000	2016 v.1
Metl Span	Panel manufacturing	15422	A01	30800802	25	1.13	0.003	0.003	1.1300	0.0031	0.0031	0.0000	2016 v.1
Artesian Spas	Spray booth with RTO	15426	A01	30800724	25	0.23	0.001	0.001	0.2300	0.0006	0.0006	0.0000	2016 v.1
Red Rock Casino Resort	Boiler	15487	A	10300602	25	0.31	0.001	0.001	0.3100	0.0008	0.0008	0.0000	default value
Red Rock Casino Resort	Generator	15487	B	20300101	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
South Point Hotal and Casino	Boiler	15515	A	10300602	25	0.23	0.001	0.001	0.2300	0.0006	0.0006	0.0000	2016 v.1
South Point Hotal and Casino	Generator	15515	B	20300101	25	2.98	0.008	0.008	2.9800	0.0082	0.0082	0.0000	2016 v.1
World Market Center	Boiler	15541	B	10300602	25	7.12	0.020	0.020	7.1200	0.0195	0.0195	0.0000	2016 v.1
Westgate Las Vegas	Boiler	15541	A	10300603	25	0.29	0.001	0.001	0.2900	0.0008	0.0008	0.0000	2016 v.1
CDW Logistics	Generator	15634	A	20300101	25	1.87	0.005	0.005	1.8700	0.0051	0.0051	0.0000	default value
Manheim Nevada	Generator	15839	C	20100102	25	7.45	0.020	0.020	7.4500	0.0204	0.0204	0.0000	2016 v.1
Manheim Nevada	Heater	15839	B	40201001	25	11.53	0.032	0.032	11.5300	0.0316	0.0316	0.0000	2016 v.1
City of Henderson Downtown	Boiler	15847	B	10300603	25	1.14	0.003	0.003	1.1400	0.0031	0.0031	0.0000	default value
City of Henderson Downtown	Generator	15847	G	20300101	25	0.11	0.000	0.000	0.1100	0.0003	0.0003	0.0000	default value
Centennial Hills Hospital	Boiler	15873	A	10300602	25	26.74	0.073	0.073	26.7400	0.0733	0.0733	0.0000	2016 v.1
Centennial Hills Hospital	Generator	15873	C	20300101	25	0.03	0.000	0.000	0.0300	0.0001	0.0001	0.0000	2016 v.1
Plasticard Locktech	Heater	15876	B	10300603	25	33.83	0.093	0.093	33.4646	0.0917	0.0917	-0.0012	2016 v.1
Plasticard Locktech	Press	15876	A	40202201	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
Veterans Administration	Boiler	15970	B	10300602	25	0.10	0.000	0.000	0.1000	0.0003	0.0003	0.0000	default value
Verizon Business	Generator	15970	A	20300101	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
2755 Las Vegas	Boiler	15999	A	10300602	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
2755 Las Vegas	Generator	15999	B	20300101	25	1.00	0.003	0.003	1.0000	0.0027	0.0027	0.0000	default value

Cosmopolitan Las Vegas	Boiler	16101	A	10300602	25	0.18	0.000	0.000	0.1800	0.0005	0.0005	0.0000	default value
Cosmopolitan Las Vegas	Generator	16101	B	20300101	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
Biodiesel of Las Vegas	Fire Pump	16118	C01	20200102	25	0.04	0.000	0.000	0.0400	0.0001	0.0001	0.0000	default value
Ritchie Brothers	Generator	16172	G	20300101	25	4.68	0.013	0.013	4.8527	0.0133	0.0133	0.0041	2016 v.1
Switch	Generator	16258	B	20300101	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
Beltway Complex	Generator	16290	A	20300101	25	2.34	0.006	0.006	2.3400	0.0064	0.0064	0.0000	2016 v.1
Erickson International	RTO	16295	C	30190013	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
Erickson International	Dryer	16295	B	40200101	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
GE Transport	Parts Washer	16300	A	40201501	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
Switch Communications	Generator	16304	A	20022102	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
Pro Terminal Operators	Loading Rack	16376	A07	40400150	25	0.07	0.000	0.000	0.0700	0.0002	0.0002	0.0000	default value
Treasure Island	Generator	16452	A	20300101	25	0.08	0.000	0.000	0.0800	0.0002	0.0002	0.0000	default value
Clark County Downtown Campus	Boiler	16665	A	10300603	25	12.87	0.035	0.035	11.8860	0.0326	0.0326	-0.0085	2016 v.1
Clark County Downtown Campus	Generator	16665	B	20300101	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
CTC Crushing	Generator	16673	B	20300101	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	2016 v.1
Freeman	Generator	16684	B	20300101	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	2016 v.1
Terra Firma Organics	Generator	16706	B	20300101	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	2016 v.1
Resorts World	Boiler	16925	B	10300602	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	2016 v.1
Resorts World	Generator	16925	A	20300101	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	2016 v.1
Preferred Laminations	Surface Coating	17220	A	40202501	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
Viawest	Generator	17272	A	20300101	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	default value
Blue Diamond Hill Gypsum	Engines	17286	C	20300101	25	18.94	0.052	0.052	18.9400	0.0519	0.0519	0.0000	2016 v.1
Blue Diamond Hill Gypsum	Blasting	17286	A001	30504001	25	0.00	0.000	0.000	0.0000	0.0000	0.0000	0.0000	2016 v.1
Shelby American	Heater	17347	A03	39990003	25	5.74	0.016	0.016	5.7400	0.0157	0.0157	0.0000	2016 v.1
NBC Fourth Realty	Generator	17439	A	20301001	25	13.05	0.036	0.036	13.0500	0.0358	0.0358	0.0000	2016 v.1

Wells Cargo	Drum Mixer	17749	C02	30500257	25	3.91	0.011	0.011	3.9140	0.010	0.0107	0.0000	2016 v.1
Wells Cargo Lone Mountain	Blasting	17749	B	30504001	25	4.68	0.013	0.013	4.6800	0.0128	0.0128	0.0000	default value
Progress Rail	Parts Washer	17918	A01	10300603	25	0.23	0.001	0.001	0.2300	0.0006	0.0006	0.0000	2016 v.1
Total						**1027.43**	**2.81**	**2.92**	**1183.63**	**3.24**	**3.38**		

Table B2. HA 212 unit-level point source VOC emissions for 2017 and 2026.

Facility Name	Description	Facility ID	Emission Unit ID	SCC	Summer Proportion (%)	2017 Actual TPY	2017 TPD	2017 summer TPD	2026 TPY	2026 TPD	2026 summer TPD	2016-2026 Per year Growth Factor	Source
Certain Teed Gypsum	Generator	4	B8	20200401	25	0.010	0.0000	0.0000	0.0100	0.0000	0.0000	0.0000	default value
Certain Teed Gypsum	Generator	4	4-L4	20200401	25	0.190	0.0005	0.0005	0.1900	0.0005	0.0005	0.0000	default value
Certain Teed Gypsum	Grinder	4	4-F1	30501502	25	0.310	0.0008	0.0008	0.3549	0.0010	0.0010	0.0161	2016 v.1
Certain Teed Gypsum	Continuous Calciner	4	4-G1	30501511	25	0.100	0.0003	0.0003	0.1145	0.0003	0.0003	0.0161	2016 v.1
Certain Teed Gypsum	Impact Mill	4	4-E11	30501513	25	0.290	0.0008	0.0008	0.3320	0.0009	0.0009	0.0161	2016 v.1
Certain Teed Gypsum	Dryer	4	4-J3	30501520	25	0.700	0.0019	0.0019	0.8014	0.0022	0.0022	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	27	20100201	27	0.260	0.0007	0.0008	0.2977	0.0008	0.0009	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	35	20100201	27	0.300	0.0008	0.0009	0.3435	0.0009	0.0010	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	38	20100201	27	0.300	0.0008	0.0009	0.3435	0.0009	0.0010	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	37	20100201	27	0.320	0.0009	0.0009	0.3664	0.0010	0.0011	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	33	20100201	27	0.330	0.0009	0.0010	0.3778	0.0010	0.0011	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	29	20100201	27	0.340	0.0009	0.0010	0.3893	0.0011	0.0012	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	36	20100201	27	0.360	0.0010	0.0011	0.4122	0.0011	0.0012	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	31	20100201	27	0.390	0.0011	0.0012	0.4465	0.0012	0.0013	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	28	20100201	27	0.440	0.0012	0.0013	0.5038	0.0014	0.0015	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	32	20100201	27	0.440	0.0012	0.0013	0.5038	0.0014	0.0015	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	34	20100201	27	0.470	0.0013	0.0014	0.5381	0.0015	0.0016	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	4	20100201	27	0.520	0.0014	0.0015	0.5953	0.0016	0.0018	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	30	20100201	27	0.540	0.0015	0.0016	0.6182	0.0017	0.0018	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	7	20100201	27	1.830	0.0050	0.0054	2.0952	0.0057	0.0062	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	5	20100201	27	2.290	0.0063	0.0068	2.6218	0.0072	0.0078	0.0161	2016 v.1

NV Energy (Clark Station)	Turbine	7	8	20100201	27	2.440	0.0067	0.0072	2.7936	0.0077	0.0083	0.0161	2016 v.1
NV Energy (Clark Station)	Turbine	7	6	20100201	27	2.530	0.0069	0.0075	2.8966	0.0079	0.0086	0.0161	2016 v.1
NV Energy (Clark Station)	Generator	7	21	20200102	27	0.010	0.0000	0.0000	0.0114	0.0000	0.0000	0.0161	2016 v.1
NV Energy (Clark Station)	Generator	7	45	20200102	27	0.010	0.0000	0.0000	0.0114	0.0000	0.0000	0.0161	2016 v.1
Olin Chlor Alkali Products	Generator	9	1	20200102	25	0.290	0.0008	0.0008	0.3320	0.0009	0.0009	0.0161	2016 v.1
Wells Cargo	Asphalt Oil Heater	12	2	30500206	25	0.030	0.0001	0.0001	0.0343	0.0001	0.0001	0.0161	2016 v.1
Wells Cargo	Drum Mixer	12	1	30500257	25	8.760	0.0240	0.0240	10.0293	0.0275	0.0275	0.0161	2016 v.1
Wells Cargo	Fugitives	12	3	30500298	25	5.360	0.0147	0.0147	6.1367	0.0168	0.0168	0.0161	2016 v.1
Kinder Morgan	Diesel Pump	13	D02	20200102	25	0.005	0.0000	0.0000	0.0057	0.0000	0.0000	0.0161	2016 v.1
Kinder Morgan	Flare Processing	13	B10	30600904	25	0.028	0.0001	0.0001	0.0321	0.0001	0.0001	0.0161	2016 v.1
Kinder Morgan	Thermal Oxidizer	13	SR04	50410312	25	59.300	0.1625	0.1625	67.8926	0.1860	0.1860	0.0161	2016 v.1
Titanium Metals Corp.	CO Burner/Boiler	19	B06	10201402	25	0.170	0.0005	0.0005	0.1946	0.0005	0.0005	0.0161	2016 v.1
Titanium Metals Corp.	Hot Oil Heater	19	C05	30301201	25	0.059	0.0002	0.0002	0.0675	0.0002	0.0002	0.0161	2016 v.1
Titanium Metals Corp.	Fugitives	19	A01	30301299	25	2.141	0.0059	0.0059	2.4512	0.0067	0.0067	0.0161	2016 v.1
Northwind Alladin	Boiler	26	1	10300603	25	0.210	0.0006	0.0006	0.2100	0.0006	0.0006	0.0000	default value
Circus Circus Hotel and Casino	Boiler	47	1	10300603	25	0.610	0.0017	0.0017	0.6100	0.0017	0.0017	0.0000	2016 v.1
CCWRD Flamingo Center	Boiler	54	1	10300603	25	3.390	0.0093	0.0093	3.3900	0.0093	0.0093	0.0000	2016 v.1
BKEP Materials	Boiler	67	1	10300603	25	0.720	0.0020	0.0020	0.7200	0.0020	0.0020	0.0000	2016 v.1
Las Vegas Paving - Blue Diamond	Drum Mixer	70	B12	30500257	25	4.970	0.0136	0.0136	4.9700	0.0136	0.0136	0.0000	2016 v.1
Golden Nugget Hotel and Casino	Boiler	81	1	10300603	25	0.150	0.0004	0.0004	0.1500	0.0004	0.0004	0.0000	2016 v.1
Horseshoe Club	Boiler	85	1	10300603	25	0.960	0.0026	0.0026	0.9600	0.0026	0.0026	0.0000	2016 v.1
Tronox	Boiler	95	A07	10300602	25	0.040	0.0001	0.0001	0.0400	0.0001	0.0001	0.0000	2016 v.1
Tronox	Boiler	95	A05	10300602	25	0.930	0.0025	0.0025	0.9300	0.0025	0.0025	0.0000	2016 v.1
Tronox	Generator	95	A01	20300101	25	0.001	0.0000	0.0000	0.0010	0.0000	0.0000	0.0000	2016 v.1
Tronox	Generator	95	A02	20300101	25	0.010	0.0000	0.0000	0.0100	0.0000	0.0000	0.0000	2016 v.1

Tronox	Generator	95	A03	20300101	25	0.010	0.0000	0.0000	0.0100	0.0000	0.0000	0.0000	2016 v.1
Tronox	Generator	95	A04	20300101	25	0.030	0.0001	0.0001	0.0300	0.0001	0.0001	0.0000	2016 v.1
Tronox	Chem. Manufacturing	95	A15	30107002	25	0.070	0.0002	0.0002	0.0700	0.0002	0.0002	0.0000	2016 v.1
Tronox	Chem. Manufacturing	95	A10	30107002	25	0.330	0.0009	0.0009	0.3300	0.0009	0.0009	0.0000	2016 v.1
Westgate Las Vegas	Boiler	101	B	10300603	25	0.580	0.0016	0.0016	0.5800	0.0016	0.0016	0.0000	2016 v.1
Westgate Las Vegas	Generator	101	G	20100102	25	0.010	0.0000	0.0000	0.0100	0.0000	0.0000	0.0000	2016 v.1
Las Vegas Paving - 5th Street	Fire Pump	104	E02	20200102	25	0.030	0.0001	0.0001	0.0300	0.0001	0.0001	0.0000	2016 v.1
Las Vegas Paving - 5th Street	Drum Mixer	104	E01	30500205	25	5.190	0.0142	0.0142	5.1900	0.0142	0.0142	0.0000	2016 v.1
Las Vegas Paving - 5th Street	Oil Heater	104	H01	30500206	25	0.030	0.0001	0.0001	0.0300	0.0001	0.0001	0.0000	2016 v.1
Las Vegas Paving - 5th Street	Asphalt Silos	104	B19	30500213	25	2.110	0.0058	0.0058	2.1100	0.0058	0.0058	0.0000	2016 v.1
Las Vegas Paving - 5th Street	Truck Loadout	104	B17	30500214	25	0.680	0.0019	0.0019	0.6800	0.0019	0.0019	0.0000	2016 v.1
Las Vegas Paving - 5th Street	Drum Dryer	104	E03	39001089	25	0.520	0.0014	0.0014	0.5200	0.0014	0.0014	0.0000	2016 v.1
Las Vegas Paving - 5th Street	UST	104	G01	40600706	25	0.140	0.0004	0.0004	0.1400	0.0004	0.0004	0.0000	2016 v.1
Las Vegas Paving - Lone Mountain	Generator	105	C	20200102	25	1.690	0.0046	0.0046	1.6900	0.0046	0.0046	0.0000	2016 v.1
Las Vegas Paving - Lone Mountain	Drum Dryer	105	B012	30500205	25	3.320	0.0091	0.0091	3.3200	0.0091	0.0091	0.0000	2016 v.1
Las Vegas Paving - Lone Mountain	Oil Heater	105	B011	30500209	25	0.020	0.0001	0.0001	0.0264	0.0001	0.0001	0.0357	2016 v.1
Las Vegas Paving - Lone Mountain	Asphalt Silos	105	B013	30500213	25	0.080	0.0002	0.0002	0.1057	0.0003	0.0003	0.0357	2016 v.1
McCarran International Airport	Boiler	108	A	10300602	25	0.800	0.0022	0.0022	1.0570	0.0029	0.0029	0.0357	2016 v.1
McCarran International Airport	Generator	108	E	20200102	25	0.140	0.0004	0.0004	0.1850	0.0005	0.0005	0.0357	2016 v.1
McCarran International Airport	Paint Booth	108	S01	40201101	25	0.170	0.0005	0.0005	0.2246	0.0006	0.0006	0.0357	2016 v.1
McCarran International Airport	AST	108	W01	40600401	25	0.190	0.0005	0.0005	0.2510	0.0007	0.0007	0.0357	2016 v.1
Nellis AFB	Nat gas boilers	114	RB-C	10300602	25	0.400	0.0011	0.0011	0.5285	0.0014	0.0014	0.0357	2016 v.1
Nellis AFB	Internal Combustion	114	G	20300301	25	0.310	0.0008	0.0008	0.1767	0.0005	0.0005	-0.0478	IPM
Nellis AFB	Hush House	114	N	20400110	25	0.530	0.0015	0.0015	0.0353	0.0001	0.0001	-0.1037	IPM

Nellis AFB	Misc Chemicals	114	O	24600000	25	6.140	0.0168	0.0168	8.1128	0.0222	0.0222	0.0357	2016 v.1
Nellis AFB	Drum Mixer	114	A047	30500205	25	0.120	0.0003	0.0003	0.1586	0.0004	0.0004	0.0357	2016 v.1
Nellis AFB	Degreasers	114	M	40100336	25	0.080	0.0002	0.0002	0.1057	0.0003	0.0003	0.0357	2016 v.1
Nellis AFB	Surface coating	114	D	40202501	25	1.400	0.0038	0.0038	1.8498	0.0051	0.0051	0.0357	2016 v.1
Nellis AFB	Fuel dispensing	114	J	40688801	25	5.300	0.0145	0.0145	7.0029	0.0192	0.0192	0.0357	2016 v.1
SLS Las Vegas	Boiler	133	A	10300602	25	0.250	0.0007	0.0007	0.0901	0.0002	0.0002	-0.0711	IPM
SLS Las Vegas	Generator	133	B	20300101	25	0.050	0.0001	0.0001	0.0179	0.0000	0.0000	-0.0714	IPM
University Medical Center	Boiler	142	A	10300603	25	0.410	0.0011	0.0011	0.5417	0.0015	0.0015	0.0357	2016 v.1
University Medical Center	Generator	142	B	20300101	25	0.080	0.0002	0.0002	0.1057	0.0003	0.0003	0.0357	2016 v.1
Las Vegas Paving	Drum Mixer	186	B013	30500205	25	2.040	0.0056	0.0056	2.6955	0.0074	0.0074	0.0357	2016 v.1
Las Vegas Paving	Oil Heater	186	B023	30500208	25	0.010	0.0000	0.0000	0.0132	0.0000	0.0000	0.0357	2016 v.1
Las Vegas Paving	Waste Silo	186	B017	30500213	25	0.060	0.0002	0.0002	0.0793	0.0002	0.0002	0.0357	2016 v.1
Las Vegas Paving	Truck Loadout	186	B020	30500214	25	0.260	0.0007	0.0007	0.3435	0.0009	0.0009	0.0357	2016 v.1
Caesars Consolidated	Boiler	257	1	10300603	25	2.000	0.0055	0.0055	2.6426	0.0072	0.0072	0.0357	2016 v.1
Mirage/Treasure Island	Boiler	282	1	10300603	25	1.010	0.0028	0.0028	1.3345	0.0037	0.0037	0.0357	2016 v.1
Brady Linen Services	Dryer	322	1	30504033	25	1.480	0.0041	0.0041	1.9555	0.0054	0.0054	0.0357	2016 v.1
Catalina Plastic and Coating	Plastics	323	1	40201399	25	11.130	0.0305	0.0305	14.706 1	0.0403	0.0403	0.0357	2016 v.1
Las Vegas Cogeneration	Generator	329	10	20100102	51	0.010	0.0000	0.0001	0.0132	0.0000	0.0001	0.0357	2016 v.1
Las Vegas Cogeneration	Generator	329	11	20100102	51	0.020	0.0001	0.0001	0.0264	0.0001	0.0001	0.0357	2016 v.1
Las Vegas Cogeneration	Turbine	329	1	20100201	51	0.680	0.0019	0.0038	0.8985	0.0025	0.0050	0.0357	2016 v.1
Las Vegas Cogeneration	Turbine	329	3	20100201	51	0.980	0.0027	0.0055	1.2949	0.0035	0.0072	0.0357	2016 v.1
Las Vegas Cogeneration	Turbine	329	5	20100201	51	1.340	0.0037	0.0075	1.7705	0.0049	0.0099	0.0357	2016 v.1
Las Vegas Cogeneration	Turbine	329	6	20100201	51	1.350	0.0037	0.0075	1.7838	0.0049	0.0100	0.0357	2016 v.1
Las Vegas Cogeneration	Turbine	329	4	20100201	51	1.410	0.0039	0.0079	1.8630	0.0051	0.0104	0.0357	2016 v.1
Boral Roofing	Curing Tunnel	346	B18	30500850	25	0.010	0.0000	0.0000	0.0132	0.0000	0.0000	0.0357	2016 v.1
Boral Roofing	Surface coating	346	AB	40299995	25	2.860	0.0078	0.0078	3.7789	0.0104	0.0104	0.0357	2016 v.1

Aggregate Industries	Boiler	372	10	10300602	25	0.120	0.0003	0.0003	0.1586	0.0004	0.0004	0.0357	2016 v.1
Aggregate Industries	Generator	372	1	20100102	25	3.290	0.0090	0.0090	4.3471	0.0119	0.0119	0.0357	2016 v.1
Aggregate Industries	Mineral Products	372	4	30500208	25	0.000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	2016 v.1
Aggregate Industries	Mineral Products	372	5	30500208	25	0.010	0.0000	0.0000	0.0120	0.0000	0.0000	0.0220	2016 v.1
Aggregate Industries	Mineral Products	372	2	30500208	25	0.015	0.0000	0.0000	0.0180	0.0000	0.0000	0.0220	2016 v.1
Aggregate Industries	Mineral Products	372	3	30500242	25	0.015	0.0000	0.0000	0.0183	0.0001	0.0001	0.0243	2016 v.1
Aggregate Industries	Mineral Products	372	13	30502599	25	0.030	0.0001	0.0001	0.0366	0.0001	0.0001	0.0243	2016 v.1
Saguaro Power Company	Boiler	393	5	10100601	27	0.276	0.0008	0.0008	0.3364	0.0009	0.0010	0.0243	2016 v.1
Saguaro Power Company	Boiler	393	6	10100602	27	0.137	0.0004	0.0004	0.1670	0.0005	0.0005	0.0243	2016 v.1
Saguaro Power Company	Starter	393	3	20100102	27	0.005	0.0000	0.0000	0.0061	0.0000	0.0000	0.0243	2016 v.1
Saguaro Power Company	Starter	393	4	20100102	27	0.006	0.0000	0.0000	0.0073	0.0000	0.0000	0.0243	2016 v.1
Saguaro Power Company	Generator	393	7	20100102	27	0.050	0.0001	0.0001	0.0609	0.0002	0.0002	0.0243	2016 v.1
Saguaro Power Company	Turbine	393	1	20100201	27	3.875	0.0106	0.0115	4.7225	0.0129	0.0140	0.0243	2016 v.1
Saguaro Power Company	Turbine	393	2	20100201	27	3.881	0.0106	0.0115	4.7298	0.0130	0.0140	0.0243	2016 v.1
City of Las Vegas WPCF	Generator	402	2	20200102	25	0.070	0.0002	0.0002	0.0853	0.0002	0.0002	0.0243	2016 v.1
City of Las Vegas WPCF	Generator	402	3	20200202	25	0.010	0.0000	0.0000	0.0122	0.0000	0.0000	0.0243	2016 v.1
City of Las Vegas WPCF	Waste Flare	402	5	50100789	25	0.340	0.0009	0.0009	0.4144	0.0011	0.0011	0.0243	2016 v.1
City of Las Vegas WPCF	Boilers	402	8	50100799	25	0.110	0.0003	0.0003	0.1341	0.0004	0.0004	0.0243	2016 v.1
City of Las Vegas WPCF	Boilers	402	7	50100799	25	0.210	0.0006	0.0006	0.2559	0.0007	0.0007	0.0243	2016 v.1
City of Las Vegas WPCF	Blower Engines	402	6	50100799	25	3.640	0.0100	0.0100	4.3443	0.0119	0.0119	0.0215	2016 v.1
Nikkiso Cryo	Generator	404	1	20200102	25	0.390	0.0011	0.0011	0.4623	0.0013	0.0013	0.0206	2016 v.1
Nevada Sun Peak Partnerships	Turbine	423	3	20100201	37	0.060	0.0002	0.0002	0.0711	0.0002	0.0003	0.0206	2016 v.1
Nevada Sun Peak Partnerships	Turbine	423	2	20100201	37	0.080	0.0002	0.0003	0.0948	0.0003	0.0004	0.0206	2016 v.1
Nevada Sun Peak Partnerships	Turbine	423	1	20100201	37	0.110	0.0003	0.0004	0.1304	0.0004	0.0005	0.0206	2016 v.1

Hard Rock Hotel and Casino	Boiler	510	A	10300603	25	0.230	0.0006	0.0006	0.2753	0.0008	0.0008	0.0219	2016 v.1
Hard Rock Hotel and Casino	Generator	510	B	20300101	25	0.020	0.0001	0.0001	0.0239	0.0001	0.0001	0.0219	2016 v.1
Texas Station Casino	Boiler	531	A	10300603	25	0.400	0.0011	0.0011	0.4788	0.0013	0.0013	0.0219	2016 v.1
Texas Station Casino	Generator	531	B	20300101	25	0.020	0.0001	0.0001	0.0239	0.0001	0.0001	0.0219	2016 v.1
Citibank The Lakes	Generator	546	A	20300101	25	0.010	0.0000	0.0000	0.0120	0.0000	0.0000	0.0219	2016 v.1
Rio All Suites Hotel and Casino	Boiler	555	A	10300603	25	1.580	0.0043	0.0043	1.8914	0.0052	0.0052	0.0219	2016 v.1
Rio All Suites Hotel and Casino	Generator	555	C	20300101	25	0.050	0.0001	0.0001	0.0599	0.0002	0.0002	0.0219	2016 v.1
Kurt Segler Water Reclamation	Generator	558	B	20200102	25	0.900	0.0025	0.0025	1.0774	0.0030	0.0030	0.0219	2016 v.1
Kurt Segler Water Reclamation	Waste water treatment	558	B01	50100765	25	0.240	0.0007	0.0007	0.2873	0.0008	0.0008	0.0219	2016 v.1
Stratosphere Hotel and Casino	Boiler	564	A	10300603	25	0.330	0.0009	0.0009	0.3950	0.0011	0.0011	0.0219	2016 v.1
Stratosphere Hotel and Casino	Generator	564	B	20300101	25	0.170	0.0005	0.0005	0.2035	0.0006	0.0006	0.0219	2016 v.1
Aggregate Industries - Gowan	Drum Mixer	587	A08	30500205	25	2.980	0.0082	0.0082	3.5674	0.0098	0.0098	0.0219	2016 v.1
Aggregate Industries - Gowan	Asphalt Oil Heater	587	E	30500208	25	0.070	0.0002	0.0002	0.0838	0.0002	0.0002	0.0219	2016 v.1
Aggregate Industries - Gowan	Asphalt Silos	587	A12	30500212	25	4.380	0.0120	0.0120	5.2433	0.0144	0.0144	0.0219	2016 v.1
Las Vegas Review Journal	Generator	588	D	20300101	25	0.010	0.0000	0.0000	0.0120	0.0000	0.0000	0.0219	2016 v.1
Las Vegas Review Journal	Parts Washer	588	B	40500417	25	8.080	0.0221	0.0221	9.6726	0.0265	0.0265	0.0219	2016 v.1
Berry Plastics Corporation	Generator	597	F01	20300101	25	0.010	0.0000	0.0000	0.0120	0.0000	0.0000	0.0219	2016 v.1
Berry Plastics Corporation	Offset Printing	597	E01	40500802	25	5.630	0.0154	0.0154	6.7397	0.0185	0.0185	0.0219	2016 v.1
Palace Station Hotel and Casino	Boiler	605	A	10300603	25	0.490	0.0013	0.0013	0.5866	0.0016	0.0016	0.0219	2016 v.1
Palace Station Hotel and Casino	Generator	605	B	20300101	25	0.020	0.0001	0.0001	0.0239	0.0001	0.0001	0.0219	2016 v.1
Gold Coast Hotel and Casino	Boiler	606	A	10300603	25	0.270	0.0007	0.0007	-0.0331	-0.0001	-0.0001	-0.1247	IPM
Gold Coast Hotel and Casino	Generator	606	B	20300101	25	0.060	0.0002	0.0002	0.0041	0.0000	0.0000	-0.1034	IPM
Sams Town Hotel and Casino	Boiler	616	A	10300603	25	0.230	0.0006	0.0006	-0.0277	-0.0001	-0.0001	-0.1245	IPM
Sams Town Hotel and Casino	Generator	616	B	20300101	25	0.010	0.0000	0.0000	-0.0012	0.0000	0.0000	-0.1246	IPM

Santa Fe Station	Boiler	621	A	10300603	25	0.670	0.0018	0.0018	0.6821	0.0019	0.0019	0.0020	2016 v.1
Santa Fe Station	Generator	621	B	20300101	25	0.010	0.0000	0.0000	0.0100	0.0000	0.0000	0.0000	default value
University of Nevada, Las Vegas	Boiler	634	A	10300603	25	0.740	0.0020	0.0020	0.7400	0.0020	0.0020	0.0000	2016 v.1
University of Nevada, Las Vegas	Generator	634	B	20300101	25	0.060	0.0002	0.0002	0.0600	0.0002	0.0002	0.0000	2016 v.1
Orleans Hotel and Casino	Boiler	641	A	10300603	25	0.500	0.0014	0.0014	0.5000	0.0014	0.0014	0.0000	2016 v.1
Orleans Hotel and Casino	Generator	641	B	20300101	25	0.010	0.0000	0.0000	0.0100	0.0000	0.0000	0.0000	2016 v.1
Venetian Hotel and Casino	Boiler	697	B	10300603	25	3.170	0.0087	0.0087	3.1700	0.0087	0.0087	0.0000	2016 v.1
Venetian Hotel and Casino	Generator	697	C	20300101	25	0.120	0.0003	0.0003	0.1200	0.0003	0.0003	0.0000	2016 v.1
Verizon Business	Generator	726	A	20300101	25	0.020	0.0001	0.0001	0.0200	0.0001	0.0001	0.0000	2016 v.1
Nevada Color Litho	Printing Press	754	A05	40500433	25	18.860	0.0517	0.0517	18.8600	0.0517	0.0517	0.0000	2016 v.1
JW Marriott Las Vegas	Boiler	755	A	10300603	25	0.340	0.0009	0.0009	0.3400	0.0009	0.0009	0.0000	default value
JW Marriott Las Vegas	Generator	755	B	20300101	25	0.020	0.0001	0.0001	0.0200	0.0001	0.0001	0.0000	default value
Suncoast Hotel and Casino	Boiler	775	A	10300603	25	0.230	0.0006	0.0006	0.2300	0.0006	0.0006	0.0000	default value
Suncoast Hotel and Casino	Generator	775	B	20300101	25	0.030	0.0001	0.0001	0.0300	0.0001	0.0001	0.0000	default value
Viawest	Generator	777	A	20300101	25	0.030	0.0001	0.0001	0.0300	0.0001	0.0001	0.0000	2016 v.1
Cancun Resort	Boiler	788	A	10300603	25	0.160	0.0004	0.0004	0.1600	0.0004	0.0004	0.0000	2016 v.1
Cancun Resort	Generator	788	B	20300101	25	0.020	0.0001	0.0001	0.0200	0.0001	0.0001	0.0000	2016 v.1
Clearwater Paper	Boiler	807	A10	10200602	25	0.560	0.0015	0.0015	0.5600	0.0015	0.0015	0.0000	2016 v.1
Clearwater Paper	Air heaters	807	A08	30790003	25	6.930	0.0190	0.0190	6.9300	0.0190	0.0190	0.0000	2016 v.1
Clearwater Paper	Paper process fugitives	807	F	30799998	25	14.580	0.0399	0.0399	14.5800	0.0399	0.0399	0.0000	2016 v.1
MGM Grand/New York New York	Boiler	825	A	10300603	25	5.840	0.0160	0.0160	5.8400	0.0160	0.0160	0.0000	default value
MGM Grand/New York New York	Turbine	825	E	20100201	25	0.850	0.0023	0.0023	0.8500	0.0023	0.0023	0.0000	2016 v.1
MGM Grand/New York New York	Generator	825	B	20300101	25	0.550	0.0015	0.0015	0.5500	0.0015	0.0015	0.0000	2016 v.1
MGM Grand/New York New York	Paint booth	825	C	40201101	25	1.690	0.0046	0.0046	1.6900	0.0046	0.0046	0.0000	2016 v.1

MGM Grand/New York New York	Tank	825	D	40600401	25	1.930	0.0053	0.0053	1.9300	0.0053	0.0053	0.0000	2016 v.1
Univeral Urethane	Molding machines	859	A	30800802	25	14.370	0.0394	0.0394	14.3700	0.0394	0.0394	0.0000	2016 v.1
Univeral Urethane	Spray painting booths	859	B	40202201	25	7.880	0.0216	0.0216	7.8800	0.0216	0.0216	0.0000	2016 v.1
Sunset Station	Boiler	869	A	10300603	25	0.320	0.0009	0.0009	0.3200	0.0009	0.0009	0.0000	2016 v.1
Sunset Station	Generator	869	B	20300101	25	0.020	0.0001	0.0001	0.0200	0.0001	0.0001	0.0000	2016 v.1
Yesco	Spray painting booths	974	A	40200101	25	4.820	0.0132	0.0132	4.8200	0.0132	0.0132	0.0000	2016 v.1
West Rock	Printing Press	1055	A	40500501	25	10.860	0.0298	0.0298	10.8600	0.0298	0.0298	0.0000	2016 v.1
Republic Services Transfer Station	Boiler	1087	B	10300603	25	0.010	0.0000	0.0000	0.0100	0.0000	0.0000	0.0000	2016 v.1
Republic Services Transfer Station	Generator	1087	G	20300101	25	0.440	0.0012	0.0012	0.4400	0.0012	0.0012	0.0000	2016 v.1
Republic Services Transfer Station	Spray painting booths	1087	A10	40201601	25	4.830	0.0132	0.0132	4.8300	0.0132	0.0132	0.0000	2016 v.1
Republic Services Transfer Station	UST	1087	A11	40600306	25	0.380	0.0010	0.0010	0.3800	0.0010	0.0010	0.0000	2016 v.1
Las Vegas Color Graphics	Printing Press	1149	A	40500411	25	7.300	0.0200	0.0200	7.3000	0.0200	0.0200	0.0000	2016 v.1
St Rose Dominican Siena	Boiler	1500	A	10300603	25	0.760	0.0021	0.0021	0.7600	0.0021	0.0021	0.0000	2016 v.1
St Rose Dominican Siena	Generator	1500	B	20300101	25	0.030	0.0001	0.0001	0.0300	0.0001	0.0001	0.0000	2016 v.1
Green Valley Ranch Resort	Boiler	1501	A	10300603	25	0.220	0.0006	0.0006	0.2200	0.0006	0.0006	0.0000	2016 v.1
Green Valley Ranch Resort	Generator	1501	B	20300101	25	0.010	0.0000	0.0000	0.0100	0.0000	0.0000	0.0000	2016 v.1
Palms Casino Resort	Boiler	1522	A	10300603	25	0.390	0.0011	0.0011	0.3900	0.0011	0.0011	0.0000	2016 v.1
Palms Casino Resort	Generator	1522	B	20300101	25	0.010	0.0000	0.0000	0.0100	0.0000	0.0000	0.0000	2016 v.1
Boulder Station Hotel and Casino	Boiler	1524	A	10300603	25	0.150	0.0004	0.0004	0.1500	0.0004	0.0004	0.0000	2016 v.1
Boulder Station Hotel and Casino	Generator	1524	B	20300101	25	0.030	0.0001	0.0001	0.0300	0.0001	0.0001	0.0000	2016 v.1
Mountain View Hospital	Boiler	1569	A	10300603	25	0.220	0.0006	0.0006	0.2200	0.0006	0.0006	0.0000	2016 v.1
Mountain View Hospital	Generator	1569	B	20300101	25	0.030	0.0001	0.0001	0.0300	0.0001	0.0001	0.0000	2016 v.1
Lasfuel McCarran Tank Farm	Generator	1589	C	20300101	25	0.020	0.0001	0.0001	0.0200	0.0001	0.0001	0.0000	2016 v.1
Lasfuel McCarran Tank Farm	Thermal Oxidizer	1589	B06	40400153	25	0.000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	2016 v.1

Lasfuel McCarran Tank Farm	Tank	1589	A	40400199	25	14.300	0.0392	0.0392	14.3000	0.0392	0.0392		0.0000	2016 v.1
Lasfuel McCarran Tank Farm	Loading Rack	1589	B	40400250	25	0.490	0.0013	0.0013	0.4900	0.0013	0.0013		0.0000	2016 v.1
Wynn Las Vegas	Boiler	1624	A	10300602	25	1.190	0.0033	0.0033	1.1900	0.0033	0.0033		0.0000	2016 v.1
Wynn Las Vegas	Generator	1624	C	20100102	25	0.320	0.0009	0.0009	0.3200	0.0009	0.0009		0.0000	2016 v.1
Wynn Las Vegas	Dry Cleaning	1624	R	40100103	25	0.240	0.0007	0.0007	0.2400	0.0007	0.0007		0.0000	2016 v.1
Wynn Las Vegas	AST	1624	F	40600306	25	0.070	0.0002	0.0002	0.0700	0.0002	0.0002		0.0000	2016 v.1
North Las Vegas Airport	Tank	9596	A	40600706	25	1.400	0.0038	0.0038	1.4000	0.0038	0.0038		0.0000	2016 v.1
Henderson Executive Airport	Tank	9603	A	40600706	25	0.860	0.0024	0.0024	0.8600	0.0024	0.0024		0.0000	2016 v.1
Brady Linen Services	Boiler	10201	B	10200602	25	0.880	0.0024	0.0024	0.8800	0.0024	0.0024		0.0000	2016 v.1
Brady Linen Services	Dry Cleaning	10201	M	41000115	25	1.760	0.0048	0.0048	1.8265	0.0050	0.0050		0.0042	2016 v.1
Brady Linen Services	Dryer	10201	D	41000130	25	0.990	0.0027	0.0027	1.3393	0.0037	0.0037		0.0392	2016 v.1
Republic Services (Sunrise)	Flare	15033	1	50300601	25	1.190	0.0033	0.0033	1.1900	0.0033	0.0033		0.0000	default value
CPP Acquisition	Dryer	15193	D	40500101	25	0.670	0.0018	0.0018	0.6700	0.0018	0.0018		0.0000	2016 v.1
CPP Acquisition	Printer	15193	P	40500401	25	20.490	0.0561	0.0561	20.4900	0.0561	0.0561		0.0000	2016 v.1
McCarran Rent a Car Center	Boiler	15409	A	10300603	25	0.010	0.0000	0.0000	0.0100	0.0000	0.0000		0.0000	2016 v.1
McCarran Rent a Car Center	Tank	15409	T	40600306	25	8.390	0.0230	0.0230	8.3900	0.0230	0.0230		0.0000	2016 v.1
Metl Span	Panel manufacturing	15422	A01	30800802	25	2.420	0.0066	0.0066	2.4200	0.0066	0.0066		0.0000	2016 v.1
Metl Span	Panel Coating	15422	A05	30801005	25	2.180	0.0060	0.0060	2.1800	0.0060	0.0060		0.0000	2016 v.1
Artesian Spas	Frame and skirting process	15426	A06	24010900	25	0.660	0.0018	0.0018	0.6600	0.0018	0.0018		0.0000	2016 v.1
Artesian Spas	Spray booth with RTO	15426	A01	30800724	25	1.530	0.0042	0.0042	1.5300	0.0042	0.0042		0.0000	default value
Artesian Spas	Plumbing system installation	15426	A05	30800799	25	4.780	0.0131	0.0131	4.7800	0.0131	0.0131		0.0000	2016 v.1
Red Rock Casino Resort	Boiler	15487	A	10300602	25	0.490	0.0013	0.0013	0.4900	0.0013	0.0013		0.0000	default value
Red Rock Casino Resort	Generator	15487	B	20300101	25	0.030	0.0001	0.0001	0.0300	0.0001	0.0001		0.0000	default value
South Point Hotal and Casino	Boiler	15515	A	10300602	25	0.530	0.0015	0.0015	0.5300	0.0015	0.0015		0.0000	2016 v.1

South Point Hotal and Casino	Generator	15515	B	20300101	25	0.030	0.0001	0.0001	0.0300	0.0001	0.0001	0.0000	2016 v.1
World Market Center	Boiler	15541	A	10300602	25	0.020	0.0001	0.0001	0.0200	0.0001	0.0001	0.0000	2016 v.1
World Market Center	Generator	15541	B	20300101	25	0.060	0.0002	0.0002	0.0600	0.0002	0.0002	0.0000	default value
CDW Logistics	Generator	15634	A	20300101	25	0.040	0.0001	0.0001	0.0400	0.0001	0.0001	0.0000	default value
Manheim Nevada	Generator	15839	C	20100102	25	0.020	0.0001	0.0001	0.0200	0.0001	0.0001	0.0000	default value
Manheim Nevada	Heater	15839	B	40201001	25	0.280	0.0008	0.0008	0.2800	0.0008	0.0008	0.0000	default value
Manheim Nevada	Paint booth	15839	A	40201601	25	4.430	0.0121	0.0121	4.4300	0.0121	0.0121	0.0000	default value
Manheim Nevada	AST	15839	D	40600401	25	0.990	0.0027	0.0027	0.9900	0.0027	0.0027	0.0000	default value
City of Henderson Downtown	Boiler	15847	B	10300603	25	0.230	0.0006	0.0006	0.2300	0.0006	0.0006	0.0000	2016 v.1
City of Henderson Downtown	Generator	15847	G	20300101	25	0.030	0.0001	0.0001	0.0300	0.0001	0.0001	0.0000	default value
Centennial Hills Hospital	Boiler	15873	A	10300602	25	0.320	0.0009	0.0009	0.3200	0.0009	0.0009	0.0000	default value
Centennial Hills Hospital	Generator	15873	C	20300101	25	0.020	0.0001	0.0001	0.0200	0.0001	0.0001	0.0000	default value
Plasticard Locktech	Heater	15876	B	10300603	25	0.100	0.0003	0.0003	0.1000	0.0003	0.0003	0.0000	default value
Plasticard Locktech	Press	15876	A	40202201	25	10.640	0.0292	0.0292	10.6400	0.0292	0.0292	0.0000	default value
Veterans Administration	Boiler	15970	A	10300602	25	0.130	0.0004	0.0004	0.1298	0.0004	0.0004	-0.0002	2016 v.1
Veterans Administration	Generator	15970	B	20300101	25	0.740	0.0020	0.0020	0.7387	0.0020	0.0020	-0.0002	2016 v.1
2755 Las Vegas	Boiler	15999	A	10300602	25	0.000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0180	2016 v.1
2755 Las Vegas	Generator	15999	B	20300101	25	0.030	0.0001	0.0001	0.0349	0.0001	0.0001	0.0180	2016 v.1
Cosmopolitan Las Vegas	Boiler	16101	A	10300602	25	0.900	0.0025	0.0025	1.0458	0.0029	0.0029	0.0180	2016 v.1
Cosmopolitan Las Vegas	Generator	16101	B	20300101	25	0.010	0.0000	0.0000	0.0116	0.0000	0.0000	0.0180	2016 v.1
Biodiesel of Las Vegas	Fire Pump	16118	C01	20200102	25	0.040	0.0001	0.0001	0.0400	0.0001	0.0001	0.0000	default value
Ritchie Brothers	Paint booth	16172	A01	40201601	25	0.960	0.0026	0.0026	0.9600	0.0026	0.0026	0.0000	default value
Switch	Generator	16258	B	20300101	25	0.130	0.0004	0.0004	0.1146	0.0003	0.0003	-0.0132	2016 v.1
Beltway Complex	Generator	16290	A	20300101	25	0.040	0.0001	0.0001	0.0353	0.0001	0.0001	-0.0130	2016 v.1

Beltway Complex	AST	16290	A14	40600306	25	0.290	0.0008	0.0008	0.2900	0.0008	0.0008	0.0000	2016 v.1
Erickson International	RTO	16295	B	30190013	25	0.020	0.0001	0.0001	0.0200	0.0001	0.0001	0.0000	default value
Erickson International	Dryer	16295	C	40200101	25	0.020	0.0001	0.0001	0.0200	0.0001	0.0001	0.0000	2016 v.1
Erickson International	Laminator	16295	A	40200701	25	1.970	0.0054	0.0054	1.9700	0.0054	0.0054	0.0000	2016 v.1
GE Transport	Parts Washer	16300	A	40201501	25	1.040	0.0028	0.0028	1.0400	0.0028	0.0028	0.0000	default value
Switch Communications	Generator	16304	A	20022102	25	0.510	0.0014	0.0014	0.4985	0.0014	0.0014	-0.0025	2016 v.1
Pro Terminal Operators	Loading Rack	16376	A07	40400150	25	15.390	0.0422	0.0422	15.9717	0.0438	0.0438	0.0042	2016 v.1
Pro Terminal Operators	Tanks	16376	A	40400178	25	12.180	0.0334	0.0334	12.3006	0.0337	0.0337	0.0011	2016 v.1
Treasure Island	Boiler	16452	A	10300603	25	0.630	0.0017	0.0017	0.6538	0.0018	0.0018	0.0042	2016 v.1
Treasure Island	Spray booth	16452	C01	40200102	25	0.290	0.0008	0.0008	0.3010	0.0008	0.0008	0.0042	2016 v.1
Clark County Downtown Campus	Boiler	16665	A	10300603	25	0.710	0.0019	0.0019	0.7100	0.0019	0.0019	0.0000	default value
Clark County Downtown Campus	Generator	16665	B	20300101	25	0.110	0.0003	0.0003	0.1100	0.0003	0.0003	0.0000	default value
CTC Crushing	Generator	16673	B	20300101	25	0.610	0.0017	0.0017	0.6100	0.0017	0.0017	0.0000	default value
Freeman	Generator	16684	B	20300101	25	0.010	0.0000	0.0000	0.0100	0.0000	0.0000	0.0000	default value
Freeman	Spray booth	16684	D	40200102	25	0.660	0.0018	0.0018	0.6600	0.0018	0.0018	0.0000	default value
Terra Firma Organics	Generator	16706	B	20300101	25	0.160	0.0004	0.0004	0.1600	0.0004	0.0004	0.0000	default value
Resorts World	Boiler	16925	B	10300602	25	0.000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	default value
Resorts World	Generator	16925	A	20300101	25	0.000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	default value
Preferred Laminations	Surface Coating	17220	A	40202501	25	4.410	0.0121	0.0121	4.4100	0.0121	0.0121	0.0000	default value
Viawest Lone Mountain Data Center	Generator	17272	A	20300101	25	0.030	0.0001	0.0001	0.0300	0.0001	0.0001	0.0000	default value
Blue Diamond Hill Gypsum	Engines	17286	C	20300101	25	4.280	0.0117	0.0117	4.4726	0.0123	0.0123	0.0050	2016 v.1
Shelby American	Spray booth	17347	A	40201606	25	1.540	0.0042	0.0042	1.6093	0.0044	0.0044	0.0050	2016 v.1
Shelby American	AST	17347	B01	40600306	25	0.130	0.0004	0.0004	0.1359	0.0004	0.0004	0.0050	2016 v.1
NBC Fourth Realty	Generator	17439	A	20301001	25	0.160	0.0004	0.0004	0.1600	0.0004	0.0004	0.0000	default value

Wells Cargo Lone Mountain	Engines	17749	B	20300101	25	0.170	0.0005	0.0005	0.1700	0.0005	0.0005	0.0000	2016 v.1
Wells Cargo Lone Mountain	Blasting	17749	C02	30504001	25	0.000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	2016 v.1
Progress Rail	Parts Washer	17918	A01	10300603	25	0.000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	2016 v.1
Total						**447.03**	**1.22**	**1.25**	**482.85**	**1.32**	**1.35**		

ATTACHMENT G:

Rate-of-Progress Technical Support Document

Prepared for:

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June 2024

Clark County 15% VOC Rate-of-Progress Plan: Technical Support Document

RAMBOLL

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Acronyms and Abbreviations

AIM	Architectural and Industrial Maintenance
ALAPCO	Association of Local Air Pollution Control Officials
CAA	Clean Air Act
CARB	California Air Resources Board
CCNAA	Clark County Ozone Nonattainment Area
CO	Carbon Monoxide
CTG	Control Technique Guideline
DES	Clark County Department of Environment and Sustainability
DOA	Clark County Department of Aviation
DV	Design Value
EMP	Emissions Modeling Platform
EPA	U.S. Environmental Protection Agency
EVR	Enhanced Vapor Recovery Systems
GDF	Gasoline Dispensing Facilities
HA 212	Hydrographic Area 212
HAP	Hazardous Air Pollutant
MCM	Menu of Control Measures
MOU	Memorandum of Understanding
NAICS	North American Industry Classification System
NAA	Nonattainment Area
NAAQS	National Ambient Air Quality Standard
NO_2	Nitrogen Dioxide
NOx	Nitrogen Oxides
O_3	Ozone
OTC	Ozone Transportation Commission
Pb	Lead
PM_{10}	Particulate matter less than 10 microns
$PM_{2.5}$	Particulate matter less than 2.5 microns
Ppb	Parts per billion
PTE	Permanent Total Enclosure
P/V	Pressure/Vacuum

RFG	Reformulated Gasoline
RACT	Reasonable available control technology
ROP	Rate-of-Progress
SCAQMD	South Coast Air Quality Management District
SCC	Source Classification Code
SI	Spark-ignited
SIP	State Implementation Plan
SO_2	Sulfur dioxide
SORE	Small Off-Road Engine
SMOKE	Sparse Matrix Operator Kernel Emissions
STAPPA	State and Territorial Air Pollution Program Administrators
Tpd	Tons per day
TSD	Technical Support Document
UST	Underground Storage Tank
Workgroup	AIM Coatings and Consumer Products Workgroup
VOC	Volatile Organic Compounds
VCP	Volatile Chemical Product

1.0 Introduction

The Clark County, Nevada ozone Nonattainment Area (CCNAA), also referred to as Hydrographic Area 212 (HA 212), was initially designated in June 2018 as Marginal under the 2015 ozone National Ambient Air Quality Standard (NAAQS). In January 2023, the US Environmental Protection Agency (EPA) redesignated the CCNAA to Moderate. Moderate areas are subject to additional reporting, management, and emissions reduction requirements, including the submittal of a State Implementation Plan (SIP) to the U.S. Environmental Protection Agency (EPA). Clean Air Act Section 182(b)(1) requires moderate nonattainment areas to reduce VOC emissions by 15% following the baseline year (2017). This requirement is known as the Rate of Progress (ROP) requirement.

This technical support document develops the ROP demonstration for the Clark County Department of Environment and Sustainability (DES). The document summarizes the CCNAA 2017 and 2026 emissions inventory (Chapter 2), quantifies CCNAA emissions reductions from the 2017 base year to 2026 future year (Chapter 3), describes reasonable available control technology (RACT) that result in VOC emissions reductions (Chapter 4), and describes the planned local VOC emissions control measure (Chapter 5).

2.0 2017 and 2026 Ozone Season Day Emissions Inventory Summary

The CCNAA for the 2015 ozone NAAQS consists of the Las Vegas Valley, also known as HA 212. Figure 2-1 shows the Clark County boundary and HA 212 inside Clark County. For this analysis, DES developed the 2017 base year and 2026 future year emissions estimates (collectively referred to as the 2015 Ozone ROP SIP Inventory) for ozone precursors within HA 212 only. The figure also shows a grid boundary covering HA212 used to estimate certain emissions via modeling (e.g., on-road mobile sources). The source categories included in the 2015 Ozone ROP SIP Inventory include all anthropogenic emissions categories: stationary point sources, stationary nonpoint (area) sources, on-road mobile sources, nonroad mobile sources, airports, and locomotive sources.

DES used the nonpoint, locomotive, and nonroad emissions estimates from the EPA 2017 Emissions Modeling Platform (EMP)[1] inventory and 2016v3 EMP[2] to develop the 2015 Ozone ROP SIP Inventory. The emission inventory development methodology and results are described in Ramboll (2024). The nonpoint source category includes volatile consumer products (VCP), commercial combustion, asphalt paving, residential wood combustion, and other widespread area sources. The nonroad mobile sources include a wide variety of equipment types that either move under their own power or can be moved from site to site. The nonroad mobile source emissions estimates were derived in the 2016v3 EMP using the nonroad module of the MOVES model.

The 2016v3 EMP uses EPA's new approach and data to derive emissions for VCP sources; the 2017 EMP and previous emissions inventories included VCP emissions based on an older methodology. To obtain estimates based on a consistent methodology for the baseline and future year, DES linearly interpolated the 2016v3 EMP 2016 and 2023 VCP emissions for 2017 instead of using emissions from the 2017 EMP. The Sparse Matrix Operator Kernel Emissions (SMOKE) model was run with 4-km grid spacing (Figure 2-1) for July to generate ozone season weekday emissions estimates using annual nonpoint emissions and monthly nonroad emissions data. These data are organized by source classification code (SCC) in the FF10 flat data files. CCNAA nonpoint emissions are provided by SCC in Appendix A.

DES ran MOVES4 to generate the sub-county on-road emissions inventory for HA 212. DES developed an updated county-specific MOVES input database for 2017 and 2026 with the latest local input data. Sub-county vehicular activity inputs for HA 212 were also developed using either actual activity data or spatial surrogates. DES then ran MOVES4 with the database for only HA 212 to generate the CCNAA emissions estimates for the on-road source category.

Clark County's point source inventory includes all Title V stationary and all minor sources with the potential to emit at least 10 tons of VOCs, or 25 tons of NOx, located within HA 212. 2017 point source emissions inventories were obtained from 2017 annual reports submitted by individual stationary sources. The 2017 point sources emissions were developed from either data collected by direct on-site measurements or calculated emissions using EPA emissions factors and activities data. 2026 point source emissions were estimated by extrapolating from the 2017 emissions using growth factors derived from the Technical Support Document of Second Maintenance Plan for the 1997 8-hour Ozone NAAQS (DES, 2021). Aircraft emissions in the CCNAA were also included in the point source

[1] https://www.epa.gov/air-emissions-modeling/2017-emissions-modeling-platform, Accessed Online in May 2024.
[2] https://www.epa.gov/system/files/documents/2023-03/2016v3_EmisMod_TSD_January2023_1.pdf, Accessed Online in April 2024

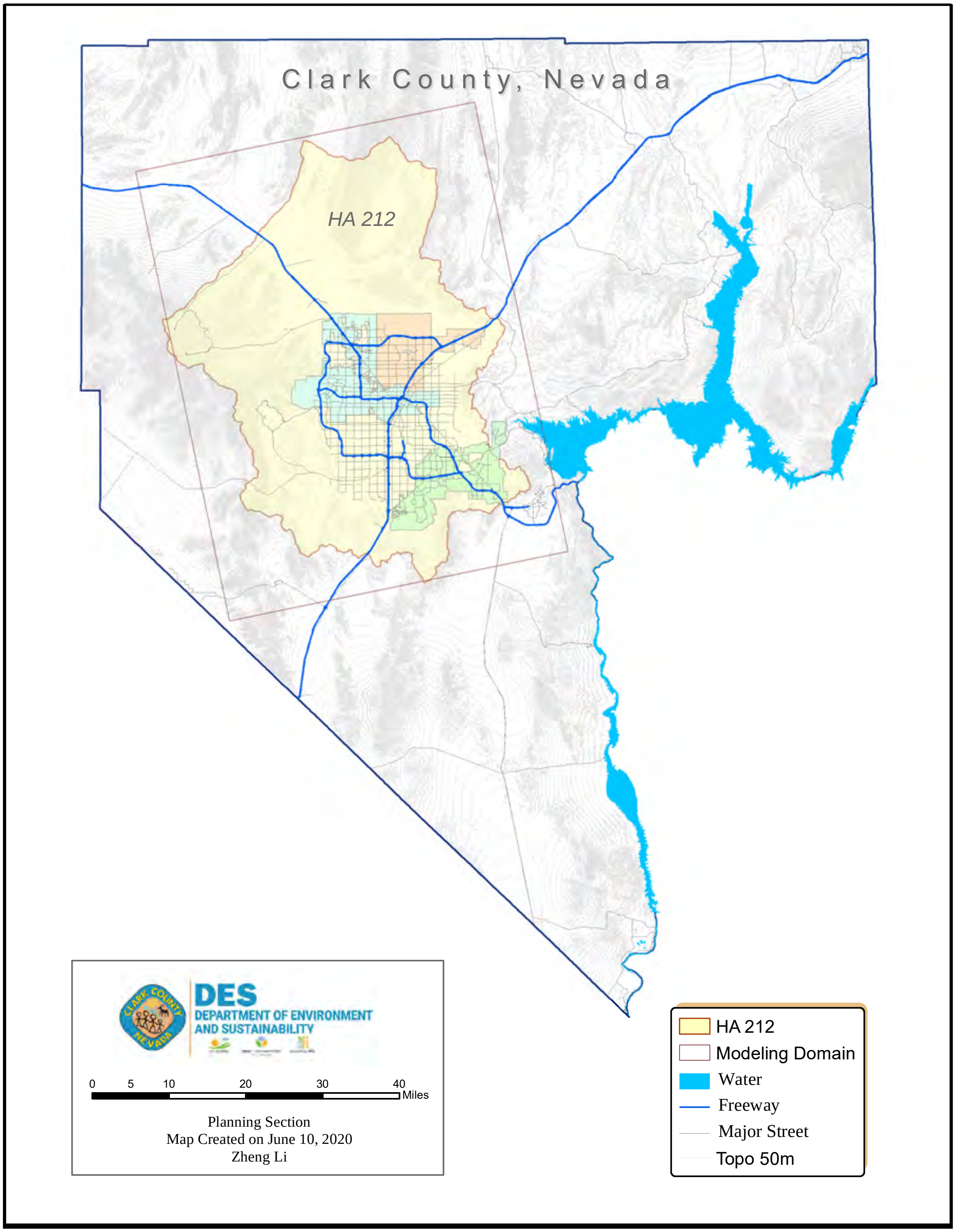

Figure 2-1. Clark County and Ozone Nonattainment Area (HA 212)

inventory. Airports within HA 212 cover commercial aviation (Harry Reid International Airport, North Las Vegas Airport, and Henderson Executive Airport) and Federal aviation (Nellis Air Force Base). Commercial aviation 2017 actual and 2023 and 2032 future year emissions were provided by the Clark County Department of Aviation (DOA); the 2026 emissions were estimated by interpolating from 2023 and 2032 emissions data. Federal aviation 2017 actual and 2026 projected emissions were obtained from Clark County's 1997 8-hour Ozone Second Maintenance Plan (DES, 2021); the 2026 emissions were estimated by interpolating from the 2023 and 2033 emissions data.

The CCNAA emissions inventory described above includes the effects on base and future year emissions of applicable on-the-books regulations such as the Tier 3 Motor Vehicle Emissions and Fuel Standards,[3] Final Rule for Control of Emissions of Air Pollution From Nonroad Diesel Engines and Fuel,[4] and Consumer Products: National Volatile Organic Compound Emissions Standards.[5]

Table 2-1 and Table 2-2 show 2017 and 2026 ozone precursor emissions estimates for the CCNAA (HA 212) by major source category representing a typical summertime weekday. On-road and nonroad mobile sources are the dominant emissions sources for NOx in 2017 followed by airports. The NOx emissions decline in the future year is primarily due to turnover in nonroad and on-road fleets. The nonpoint source category is the dominant anthropogenic emissions source for VOCs followed by on-road and nonroad mobile sources. The emissions from airports (commercial & federal) and locomotives source categories in these tables are estimated separately and excluded from the other source categories to avoid double counting.

Table 2-1. Summary of CCNAA summer weekday VOC emissions (tons per day (tpd)).

Source Category	2017 VOC	2026 VOC
Point source	1.25	1.35
Nonpoint source	57.72	61.69
On-road mobile	24.81	14.60
Nonroad mobile	24.03	24.25
Airports (commercial & Federal)	1.96	2.75
Locomotives	0.04	0.03
Emission Reduction Credits	-	0.05
Total	109.81	104.72

[3] https://www.epa.gov/regulations-emissions-vehicles-and-engines/final-rule-control-air-pollution-motor-vehicles-tier-3, Accessed Online in September 2022.
[4] https://www.epa.gov/regulations-emissions-vehicles-and-engines/final-rule-control-emissions-air-pollution-nonroad, Accessed Online in September 2022.
[5] https://www.epa.gov/stationary-sources-air-pollution/consumer-products-national-volatile-organic-compound-emission, Accessed Online in September 2022.

Table 2-2. Summary of CCNAA summer weekday NOx emissions (tpd).

Source Category	2017 NOx	2026 NOx
Point source	2.92	3.38
Nonpoint source	6.15	6.53
Onroad mobile	37.91	14.12
Nonroad mobile	36.98	19.10
Airports (commercial & Federal)	11.90	15.90
Locomotives	0.80	0.62
Emission Reduction Credits	-	0.92
Total	96.66	60.57

3.0 Summary of VOC Emissions Reductions

This section summarizes the CCNAA future year VOC emissions reductions from RACT and the planned local control measure to achieve the 15% VOC ROP requirement. Detailed descriptions of the RACT measures and planned local control measures are provided in Chapter 4 and Chapter 5, respectively.

Table 3-1 shows (i) the VOC emission reductions from 2017 baseline to 2026 future year CCNAA emissions inventories, (ii) estimated VOC emissions reductions for each RACT, (iii) planned local control measure VOC emission reductions, (iv) total VOC emission reductions, and (v) total VOC emission reductions relative to the CCNAA 2017 VOC emission inventory. Net emissions reductions from 2017 to 2026 are 16.66 tpd or 15.17%, indicating that the 15% ROP requirement can be met through implementation of the RACT and planned local control measure presented in this document.

DES projects that the CTG RACT requirements will become effective in early 2024. Efforts to finalize and adopt the AIM Coatings rule will follow closely thereafter in mid-2024. Once the rules become effective, DES expects compliance with the regulations to occur within one year, and full implementation of the rules will be reflected in the 2026 emissions inventory.

Table 3-1 CCNAA future year VOC emissions reductions .

Emission Reduction Type	Description	Future Year VOC Emission Reductions (tpd)
2017 – 2026 CCNAA VOC Emissions (see Table 2-1)	Point source	-0.10
	Nonpoint source	-3.97
	Onroad mobile	10.21
	Nonroad mobile	-0.22
	Airports (commercial & Federal)	-0.79
	Locomotives	0.01
	Emission Reduction Credits	-0.05
	Subtotals	***5.09***
Reasonable Available Control Technology	Metal and Plastic Parts Surface Coating	0.13
	Degreasing	0.33
	Industrial Adhesives	0.90
	Industrial Cleaning Solvents	3.74
	Graphic Arts	2.03
	Cutback Asphalt	0.62
	Subtotals	***7.75***
Local Control Measures	AIM Coatings OTC Model Rules: Phase I and Phase II	3.83
	Subtotals	***3.83***
Total Reductions		16.67
Percent Reduction Relative to 2017 CCNAA Anthropogenic VOC Emission Inventory		15.18

4.0 Reasonable Available Control Technology

This chapter summarizes the emissions reductions from the RACT analysis conducted by DES. The CAA requires moderate ozone nonattainment areas to implement RACT on certain stationary sources. The reclassification of HA 212 to moderate nonattainment area triggered RACT level controls within the CCNAA to reduce VOC emissions for any source category for which EPA has issued a Control Technique Guideline (CTG) document. EPA has issued a total of 46 CTG documents to date. Some documents address emissions control for more than one source category, while other documents update emissions control information addressed in older CTG documents. EPA recommends that air pollution control agencies adopt regulations that are consistent with the applicability thresholds and control level in these CTGs. The CAA also requires RACT for all major sources of ozone precursors within moderate ozone nonattainment areas.

DES has conducted a RACT analysis with detailed descriptions and will submit it to EPA as part of Clark County's RACT SIP. The emissions reductions resulting from the RACT requirement are creditable for the 15% ROP requirement.

In summary, DES reviewed the point and nonpoint emissions inventory for HA 212, business license information, minor and major New Source Review (NSR) permits, and conducted web searches to identify stationary sources that belong to CTG source categories. DES conducted this search for all issued VOC CTGs and reviewed each CTG source category group to determine if there is an operating stationary source in HA 212 such that a CTG RACT rule is needed for the source category. Based on the CTG source identification, DES will promulgate new air quality regulations for at least nine source categories:

1. Metal and Plastic Parts Surface Coating;
2. Degreasing Operations;
3. Industrial Adhesives;
4. Industrial Cleaning Solvents;
5. Graphic Arts;
6. Cutback Asphalt
7. Gasoline service stations and vapor balance systems
8. Bulk gas plants
9. Bulk gas terminals

Total estimated emissions reductions that DES projects from these CTG RACT requirements is 7.75 tpd of VOC for the CCNAA (DES, 2023) from six of the new rules. DES also found that no additional emissions reductions will result from three of the rules because they are already meeting the CTG RACT level of control (DES, 2023). Table 4-1 shows the VOC emissions reductions from the CTG RACT requirements for the CTG source categories. The CTG RACT requirements will become effective in early 2024.

Table 4-1. VOC emissions reductions from Clark County's CTG RACT requirement.

Source Category	VOC Emissions Reduction (tpd)
Metal and Plastic Parts Surface Coating	0.13
Degreasing	0.33
Industrial Adhesives	0.90
Industrial Cleaning Solvents	3.74
Graphic Arts	2.03
Cutback Asphalt	0.62
Total	7.75

5.0 Planned Local Control Measures

This chapter describes the planned local control measure that would be implemented in the CCNAA to facilitate compliance with the 15% VOC emissions reduction ROP requirement.

5.1 Architectural and Industrial Maintenance (AIM) Coatings

This section focuses on emissions reductions that are achievable for Architectural and Industrial Maintenance (AIM) coatings in the CCNAA. AIM coatings consist of surface coatings such as paint, primers, varnishes, or lacquers, as well as solvents used as thinners and for cleanup. During use, VOCs can be emitted due to the evaporation of the water-based or solvent-based liquid carriers used in these coatings. Table 5-1 summarizes key information for implementation of the control measure evaluated here: the OTC Model Rule for AIM coatings, Phases I and II. Specifically, Table 5-1 presents applicable emissions, emissions reductions, and cost-effectiveness for the CCNAA. The potential emission reductions following full implementation of the rule are reported in Table 5-1. NAA-level emissions, emissions reductions, and cost-effectiveness are described in more detail in the subsections below. The CCNAA future year 2026 emissions inventory is based on the EPA 2016v3 modeling platform. July average weekday emissions were estimated by running the SMOKE Modeling System with 2016v2 modeling platform spatial surrogates and temporal profiles to estimate CCNAA-specific emissions.[6]

Table 5-1. AIM coatings control measure summary.[a]

2026 Applicable Emissions Estimates	
NOx:	-
VOC:	7.05 tons/day
Control Measure Summary	
Future Year NOx Reduction:	-
Future Year VOC Reduction:	3.83 tons/day
Cost-effectiveness:	*Varies from $2,968 to $10,268/ton VOC*

[a] "-" indicate zero NOx emissions in the inventory and thus no emissions reductions.
[b] Calendar Year 2026 July average weekday inventory. Source: EPA 2016v3 modeling platform. Available at https://www.epa.gov/air-emissions-modeling/2016v3-platform, accessed in April 2024. The NAA is a subarea of Clark County; NAA specific emissions were estimated by allocating 2016v3 county-level emissions with 2016v3 spatial surrogates.

5.1.1 Applicable Source(s) Description

According to OTC Regulatory and Technical Guidelines, "Architectural Coating" refers to "a coating to be applied to stationary structures or their appurtenances at the site of installation, to portable buildings at the site of installation, to pavements, or to curbs. Coatings applied in shop applications or to non-stationary structures such as airplanes, ships, boats, railcars, and automobiles, as well as adhesives are not considered architectural coatings for the purposes of this rule" (OTC, 2011).

[6] https://www.epa.gov/air-emissions-modeling/2016v3-platform, accessed in April 2024.

"Industrial Maintenance Coating" refers to:

> *a high performance architectural coating, including primers, sealers, undercoaters, intermediate coats, and topcoats, formulated for application to substrates, including floors, exposed to one or more of the following extreme environmental conditions:*
>
> - *Immersion in water, wastewater, or chemical solutions (aqueous and non-aqueous solutions), or chronic exposures of interior surfaces to moisture condensation; or*
> - *Acute or chronic exposure to corrosive, caustic, or acidic agents, or to chemicals, chemical fumes, or chemical mixtures or solutions; or*
> - *Frequent exposure to temperatures above 121°C (250°F); or*
> - *Frequent heavy abrasion, including mechanical wear and frequent scrubbing with industrial solvents, cleansers, or scouring agents; or*
> - *Exterior exposure of metal structures and structural components. (OTC, 2011)*

VOCs are emitted from coatings and from the solvents used for thinners and clean-up products as the coatings dry. Table 5-2 lists the applicable SCCs for AIM Coatings in the Clark County area source inventory. AIM Coating emissions in the 2016v3 Modeling Platform emissions inventory were estimated in EPA's VCPy framework[7]. The VCPy framework is a complex calculation methodology with inputs such as 1) nationwide coating usage, 2) first-order product composition profiles to determine the fraction of coating used that may evaporate, 3) organic composition profiles to speciate potentially evaporative components, 4) compound and use specific volatilization assumptions, and 5) nation to county spatial allocation of emissions. Product usage is estimated for twelve product groupings (including paints and coating) using national-level shipment statistics, commodity prices, and producer price indices.

The first order and organic composition profiles are directly related to VOC content assumptions and therefore the control measure evaluated herein. For AIM coatings, the first-order product composition profile is taken from the California Air Resources Board's (CARB's) 2005 Architectural Coatings Survey[8]. The organic composition profile is taken from EPA's SPECIATEv5.0 database (profile 3141) for industrial coatings and from the CARB's modeling profiles for architectural coatings[9]. For the 2016v3 Modeling Platform, national emissions are disaggregated to states and counties based on spatial allocation factors such as human population, employment, etc. The spatial allocation factor for AIM coatings is human population.

Table 5-2. Applicable SCCs[10].

<table>
<tr><th>Description One</th><th>Description Two</th><th>Description Three</th><th>Description Four</th><th>SCC</th><th>2026 VOC Emissions (tons/year)</th></tr>
<tr><td rowspan="2">Solvent Utilization</td><td rowspan="2">Surface Utilization</td><td>Architectural Coatings</td><td rowspan="2">Total: All Solvent Types</td><td>2401001000</td><td>5.34</td></tr>
<tr><td>Industrial Maintenance Coatings</td><td>2401100000</td><td>1.70</td></tr>
<tr><td colspan="5">Total</td><td>7.05</td></tr>
</table>

7 Seltzer, K. M., Pennington, E., Rao, V., Murphy, B. N., Strum, M., Isaacs, K. K., and Pye, H. O. T.: Reactive organic carbon emissions from volatile chemical products, Atmos. Chem. Phys., 21, 5079-5100, https://doi.org/10.5194/acp-21-5079-2021, 2021a.

8 https://ww2.arb.ca.gov/our-work/programs/coatings/architectural-coatings/architectural-coatings-survey, accessed in April 2024.

9 https://ww2.arb.ca.gov/speciation-profiles-used-carb-modeling, accessed in April 2024.

10 The base year for this analysis is 2017. 2017 emissions were estimated by linearly interpolating 2016v2 Modeling Platform 2016 and 2023 emissions, then running SMOKE at 4-km resolution to estimate emissions within the Clark County ozone nonattainment area.

5.1.2 Control Measure Description

The OTC developed two sets of model rules in 2002 (Phase I) and 2007 (Phase II) for reducing ozone precursor emissions and thereby reducing ground-level ozone in the Northeast and Mid-Atlantic regions. These model rules are intended for the states to consider in adopting control measures to reduce VOC emissions from AIM coatings. The rules recommend regulations for AIM coatings by limiting the VOC content in the products.

The EPA published the National Volatile Organize Compound Emissions Standards for Architectural Coatings ("National Rule") on September 11, 1998, under the authority of CAA Section 183(e) to regulate emissions of VOCs from architectural coatings that can contribute to ozone pollution. The EPA identified some OTC states as having shortfalls in meeting the one-hour ozone standard. Therefore, on June 1, 2000, the OTC adopted the "Memorandum of Understanding Among the States of the Ozone Transport Commission Regarding the Development of Specific Control Measures to Support Attainment and Maintenance of the Ozone National Ambient Air Quality Standards" (MOU) to develop control measures to facilitate emissions reductions. An AIM Coatings and Consumer Products Workgroup (Workgroup) was set up to develop an OTC model rule based on the national AIM coatings model rule being developed by the State and Territorial Air Pollution Program Administrators and the Association of Local Air Pollution Control Officials (STAPPA/ALAPCO) (OTC, 2001).

STAPPA/ALAPCO's rules are more stringent than the National Rule and the Workgroup elected to use STAPPA/ALAPCO's rules as a basis for their Phase I Model Rule with a few amendments (OTC, 2000). The amendments included using 350 g/L as the VOC content limit for Industrial Maintenance Coatings instead of the 250 g/L VOC content limit in the STAPPA/ALAPCO model rule due to the temperature and humidity in the Northeast (OTC, 2001). In addition, a separate category was created for conversion varnishes with a VOC content limit of 725 g/L, and a category was created for thermoplastic rubber coatings and mastics with a VOC content limit of 550 g/L, consistent with the National Rule (OTC, 2001).

The 2010 OTC Model Rule for AIM Coatings Phase II was based on suggested control measures from CARB's 2007 Model Rule, which CARB developed to provide guidance to local districts in California. The Phase II Model Rule was developed for states that require additional VOC emissions reductions to reach attainment with the ozone standard. Phase II revised the VOC content limits for many of the coating categories, increased the stringency of some standards, and improved the definitions for many of the coating categories (OTC 2011, OTC 2016). Minor revisions were made by the OTC Workgroup on October 13, 2014. Important changes in the Phase II model rule include:

- Eliminating 15 coating categories and sub-categories and combining them with other categories;
- Adding 12 coating categories;
- Lowering VOC limits on 12 coating categories (OTC, 2016).

Several states (Massachusetts, Maine, New Hampshire, New Jersey, Pennsylvania, and Virginia) and the District of Columbia have adopted only the Phase I Model Rule for AIM Coatings. Connecticut, Delaware, Maryland, New York, and Rhode Island have adopted both the Phase I and Phase II Model Rules for AIM Coatings.

The South Coast Air Quality Management District (SCAQMD) developed its own Rule 1113 for AIM Coatings. Rule 1113 was first adopted in September 1977 to limit the emissions of VOCs from architectural coatings used in the SCAQMD. It was last amended in February 2016. It is the most stringent standard for AIM Coatings in the world and eliminates the use of many coating techniques (SCAQMD 2016a, SCAQMD 2016b, SCAQMD 2017). For example, while the OTC limit for concrete curing compounds is 350 g/L, the Rule 1113 limit is 100 g/L unless it is labeled for roads and bridges only, where it is 360 g/L (SCAQMD, 2016b). The Industrial Maintenance Coatings limit is 250 g/L for OTC, but 100 g/L for Rule 1113. The limit for Primers, Sealers, and Undercoaters is 200 g/L for OTC, but 100 g/L for Rule 1113. The limit for Stains is 250 g/L for OTC, but 100 g/L for Rule 1113 unless it is an interior stain which has a limit of 250 g/L. Waterproofing Concrete/Masonry Sealers have a limit of 400 g/L for OTC, but 100 g/L for Rule 1113. However, there is limited information to establish control efficiency and cost effectiveness for Rule 1113, and thus Rule 1113-based emissions reductions and cost are not estimated herein.

The detailed OTC Model Rules and Rule 1113 can be found in Table B1, B2 and B3 in the Appendix B.

Each OTC Model Rule phase and its estimated control efficiency are shown in Table 5-3. The control efficiency is relative to the inventory in compliance with the previous rule. The Technical Support Document (TSD) for the 2006 OTC Control Measure Evaluation estimated that the 2002 Model Rule can achieve 31% emissions reductions beyond the federal rule (OTC, 2007). The 31% emissions reduction estimate is based on the 1993 Industry Insights Survey for the National Paints and Coatings Association. The TSD published by OTC in 2016 estimated the percent reduction under the 2010 Model Rule to be 33.7% beyond the inventory in compliance with the 2002 Model Rule (OTC, 2016).

Table 5-3. Control efficiency estimates.

Control Measure	Control Efficiency (%)
OTC Model Rule for AIM Coatings Phase I	31.0
OTC Model Rule for AIM Coatings Phase II	33.7

5.1.3 Emissions Reductions

The current CCNAA VOC inventory represents the emissions from AIM coatings that are in compliance with the federal rule but does not reflect emissions reductions from more stringent rules, such as the OTC Model Rules. AIM coatings VOC emissions and emissions reductions in Clark County are presented in Table 5-4. To estimate emission reductions for OTC Model Rule Phase II, the control efficiency for OTC Model Rule Phase II in Table 5-3 is applied to emissions remaining after implementation of the OTC Model Rule Phase I; therefore, the percent reduction in Table 5-4 (23.3%) is lower than the control efficiency in Table 5-3 (33.7%). The OTC Model Rules for AIM coatings Phase I and II are estimated to achieve an overall VOC emissions reduction of 54.3%. The VOC emissions reductions are 3.83 tons/day for a future year based on the 2026 July average weekday inventory.

Table 5-4. CCNAA future year July average weekday emissions reductions.

Source	2026 Emissions (tons/day)	Control Measure	Percent Reduction	Future Year Emissions Reductions (tons/day)
AIM Coatings	7.05	OTC Model Rule for AIM Coatings Phase I (2002)	31.0%	2.19
		OTC Model Rule for AIM Coatings Phase II (2010)	23.3%	1.64
		Overall	54.3%	3.83

The OTC projected a 100% rule penetration and rule effectiveness for its rules based on "the compliance and distribution practices of this industry." (OTC, 2007) Thus, no further adjustment was made to these estimated emissions reductions.

5.1.4 Cost-effectiveness

Table 5-5 summarizes typical cost-effectiveness estimates and Table 5-6 shows estimated cost for the OTC Model Rule Phases. The cost-effectiveness was obtained from the Technical Support Documents published by the OTC accompanying the model rules (OTC 2007; OTC 2016). The cost-effectiveness is adjusted to the 2021-dollar value using the Consumer Price Index[11] to account for inflation.

Table 5-5. Typical cost-effectiveness for each control measure.

Control Measure	Cost-effectiveness (2021$/ton)	Reference
OTC Model Rule for AIM Coatings Phase I (2002)	$10,268	OTC, 2007
OTC Model Rule for AIM Coatings Phase II (2010)	$2,968	OTC, 2016
Overall across all phases	$7,129	Calculated

Table 5-6. Clark County annual cost of AIM coatings emissions reduction.

Source	Total Annual Cost (thousands of 2021$)
AIM coatings	9,940[a]

[a] Total cost of all Phases, calculated as 2023 July average weekday reduction * 365 days * cost effectiveness in $ per ton

5.1.5 Geographic Applicability

VOC emissions reductions for AIM coatings can be achieved in Clark County since AIM coatings are being used across the county.

5.1.6 Responsible Agency

The Clark County Division of Air Quality is responsible for enforcing SIP-approved control measures and other air permitting rules. The current requirement for AIM coatings is defined under Section 183(e) ("Ozone") of the Clean Air Act.

5.1.7 Implementation Schedule

After a new rule is promulgated, manufacturers are typically given time to comply with the new rule. The most recent OTC Model Rule is based on CARB's 2007 Coating Rule, amended in January 2007 which includes a three-year sell-through provision.

[11] https://www.bls.gov/cpi/data.htm, accessed in July 2022.

Efforts to finalize and adopt the AIM coating rule will take place in mid-2024. Once the rule becomes effective, DES will require full compliance by December 31, 2025, which provides an opportunity for the regulated community to use existing inventory before the compliance date.

5.1.8 Implementation Feasibility

The OTC Model Rules have been adopted by OTC members (Connecticut, Delaware, the District of Columbia, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia). Other local agencies in California such as Antelope Valley Air Quality Management District and Mojave Desert Air Quality Management District have also adopted SCAQMD Rule 1113. Therefore, the rules can be applied to reduce emissions in Clark County.

5.1.9 Public Acceptance

VOC emissions from the use of AIM coatings can cause or contribute to ozone levels that violate NAAQS for ozone. AIM coatings control measures evaluated herein are very cost-effective and therefore may be acceptable to the public. There may be local businesses or distributors who may have a negative perception of these requirements because their product costs and/or business processes may be impacted by these requirements.

6.0 References

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Appendix A Clark County Nonattainment Area Nonpoint Emissions by SCC

Appendix A Clark County Nonattainment Area Nonpoint Emissions by SCC

Table A1. CCNAA nonpoint emissions by SCC.

SCC	SCC Description	2017 (tpd)		2026 (tpd)	
		NOX	VOC	NOX	VOC
2102002000	Stationary Source Fuel Combustion; Industrial; Bituminous/Subbituminous Coal; Total: All Boiler Types	0.2112	0.0010	0.1813	0.0008
2102004001	Stationary Source Fuel Combustion; Industrial; Distillate Oil; All Boiler Types	0.1089	0.0011	0.1366	0.0014
2102004002	Stationary Source Fuel Combustion; Industrial; Distillate Oil; All IC Engine Types	2.1933	0.1525	2.7510	0.1913
2102006000	Stationary Source Fuel Combustion; Industrial; Natural Gas; Total: Boilers and IC Engines	0.9840	0.0541	0.9923	0.0683
2102007000	Stationary Source Fuel Combustion; Industrial; Liquified Petroleum Gas (LPG); Total: All Boiler Types	0.0656	0.0024	0.0075	0.0003
2102008000	Stationary Source Fuel Combustion; Industrial; Wood; Total: All Boiler Types	0.0229	0.0018	0.0224	0.0017
2103004001	Stationary Source Fuel Combustion; Commercial/Institutional; Distillate Oil; Boilers	0.0007	<0.0001	0.0007	<0.0001
2103004002	Stationary Source Fuel Combustion; Commercial/Institutional; Distillate Oil; IC Engines	0.0011	0.0001	0.0011	0.0001
2103006000	Stationary Source Fuel Combustion; Commercial/Institutional; Natural Gas; Total: Boilers and IC Engines	1.9344	0.1064	1.8027	0.1158
2103007000	Stationary Source Fuel Combustion; Commercial/Institutional; Liquified Petroleum Gas (LPG); Total: All Combustor Types	0.0750	0.0027	0.0750	0.0027
2103008000	Stationary Source Fuel Combustion; Commercial/Institutional; Wood; Total: All Boiler Types	0.0373	0.0029	0.0372	0.0029
2103011000	Stationary Source Fuel Combustion; Commercial/Institutional; Kerosene; Total: All Combustor Types	0.0005	<0.0001	0.0005	<0.0001

SCC	SCC Description	2017 (tpd)		2026 (tpd)	
		NOX	VOC	NOX	VOC
2104004000	Stationary Source Fuel Combustion; Residential; Distillate Oil; Total: All Combustor Types	0.0002	<0.0001	0.0002	<0.0001
2104006000	Stationary Source Fuel Combustion; Residential; Natural Gas; Total: All Combustor Types	0.2233	0.0131	0.2233	0.0131
2104007000	Stationary Source Fuel Combustion; Residential; Liquified Petroleum Gas (LPG); Total: All Combustor Types	0.0065	0.0003	0.0065	0.0003
2104008610	Stationary Source Fuel Combustion; Residential; Wood; Hydronic heater: outdoor	0.0002	0.0068	0.0002	0.0069
2104008620	Stationary Source Fuel Combustion; Residential; Wood; Hydronic heater: indoor	0.0001	0.0043	0.0001	0.0044
2104008630	Stationary Source Fuel Combustion; Residential; Wood; Hydronic heater: pellet-fired	<0.0001	<0.0001	<0.0001	<0.0001
2104008700	Stationary Source Fuel Combustion; Residential; Wood; Outdoor wood burning device, NEC (fire-pits, chimneys, etc.)	0.0541	0.3934	0.0611	0.4438
2285002006	Mobile Sources; Railroad Equipment; Diesel; Line Haul Locomotives: Class I Operations	0.7936	0.0366	0.6131	0.0254
2285002007	Mobile Sources; Railroad Equipment; Diesel; Line Haul Locomotives: Class II / III Operations	0.0046	0.0002	0.0047	0.0002
2302002100	Industrial Processes; Food and Kindred Products: SIC 20; Commercial Cooking - Charbroiling; Conveyorized Charbroiling	--	0.0659	--	0.0781
2302002200	Industrial Processes; Food and Kindred Products: SIC 20; Commercial Cooking - Charbroiling; Under-fired Charbroiling	--	0.2243	--	0.2657
2302003000	Industrial Processes; Food and Kindred Products: SIC 20; Commercial Cooking - Frying; Deep Fat Frying	--	0.0472	--	0.0559
2302003100	Industrial Processes; Food and Kindred Products: SIC 20; Commercial Cooking - Frying; Flat Griddle Frying	--	0.0290	--	0.0344
2302003200	Industrial Processes; Food and Kindred Products: SIC 20; Commercial Cooking - Frying; Clamshell Griddle Frying	--	0.0015	--	0.0018

SCC	SCC Description	2017 (tpd)		2026 (tpd)	
		NOX	VOC	NOX	VOC
2401001000[a]	Architectural Coatings	--	4.8222	--	5.3425
2401005000	Auto Refinishing: SIC 7532	--	0.4317	--	0.4822
2401008000	Traffic Markings	--	0.8299	--	0.7194
2401015000	Factory Finished Wood: SIC 2426 thru 242	--	0.0075	--	0.0088
2401020000	Wood Furniture: SIC 25	--	0.1210	--	0.1402
2401025000	Metal Furniture: SIC 25	--	0.1522	--	0.1763
2401030000	Paper: SIC 26	--	0.0008	--	0.0010
2401055000	Machinery and Equipment: SIC 35	--	0.0143	--	0.0165
2401065000	Electronic and Other Electrical: SIC 36 - 363	--	0.0458	--	0.0530
2401070000	Motor Vehicles: SIC 371	--	0.0161	--	0.0193
2401075000	Aircraft: SIC 372	--	0.0003	--	0.0004
2401090000	Surface Coating: Miscellaneous Manufacturing	--	0.1087	--	0.1266
2401100000[a]	Industrial Maintenance Coatings	--	1.4639	--	1.7057
2401200000	Other Special Purpose Coatings	--	0.6791	--	0.7914
2415000000	Degreasing: All Processes/All Industries	--	0.6300	--	0.6256
2420000000	Dry Cleaning	--	0.0325	--	0.0326

SCC	SCC Description	2017 (tpd)		2026 (tpd)	
		NOX	VOC	NOX	VOC
2425000000	Graphic Arts	--	2.2024	--	2.5514
2460030999	C&C: Lighter Fluid, Fire Starter, Other Fuels	--	0.1308	--	0.1494
2460100000	C&C: Personal Care Products	--	8.7457	--	9.9864
2460200000	C&C: Household Products	--	6.6442	--	7.5867
2460400000	C&C: Automotive Aftermarket Products	--	0.8215	--	0.9380
2460500000	C&C: Coatings and Related Products	--	6.5223	--	7.4476
2460600000	C&C: Adhesives and Sealants	--	5.7803	--	6.6003
2460800000	C&C: FIFRA Related Products	--	0.4702	--	0.5369
2460900000	C&C: Miscellaneous Products (Not Otherwise Covered)	--	0.1100	--	0.1256
2461021000	Cutback Asphalt	--	0.8300	--	0.7767
2461022000	Emulsified Asphalt	--	3.3588	--	3.1428
2461850000	Pesticide Application: Agricultural	--	0.0037	--	0.0001
2501011011	Storage and Transport; Petroleum and Petroleum Product Storage; Residential Portable Gas Cans; Permeation	--	0.2020	--	0.2393
2501011012	Storage and Transport; Petroleum and Petroleum Product Storage; Residential Portable Gas Cans; Evaporation (includes Diurnal losses)	--	0.2267	--	0.2685
2501011013	Storage and Transport; Petroleum and Petroleum Product Storage; Residential Portable Gas Cans; Spillage During Transport	--	0.2808	--	0.3327

SCC	SCC Description	2017 (tpd)		2026 (tpd)	
		NOX	VOC	NOX	VOC
2501011014	Storage and Transport; Petroleum and Petroleum Product Storage; Residential Portable Gas Cans; Refilling at the Pump - Vapor Displacement	--	0.0577	--	0.0683
2501011015	Storage and Transport; Petroleum and Petroleum Product Storage; Residential Portable Gas Cans; Refilling at the Pump - Spillage	--	0.0083	--	0.0098
2501012011	Storage and Transport; Petroleum and Petroleum Product Storage; Commercial Portable Gas Cans; Permeation	--	0.0097	--	0.0115
2501012012	Storage and Transport; Petroleum and Petroleum Product Storage; Commercial Portable Gas Cans; Evaporation (includes Diurnal losses)	--	0.0080	--	0.0095
2501012013	Storage and Transport; Petroleum and Petroleum Product Storage; Commercial Portable Gas Cans; Spillage During Transport	--	0.5030	--	0.5960
2501012014	Storage and Transport; Petroleum and Petroleum Product Storage; Commercial Portable Gas Cans; Refilling at the Pump - Vapor Displacement	--	0.2181	--	0.2584
2501012015	Storage and Transport; Petroleum and Petroleum Product Storage; Commercial Portable Gas Cans; Refilling at the Pump - Spillage	--	0.0210	--	0.0249
2501050120	Storage and Transport; Petroleum and Petroleum Product Storage; Bulk Terminals: All Evaporative Losses; Gasoline	--	1.2891	--	1.0622
2501055120	Storage and Transport; Petroleum and Petroleum Product Storage; Bulk Plants: All Evaporative Losses; Gasoline	--	0.0003	--	0.0002
2501060051	Storage and Transport; Petroleum and Petroleum Product Storage; Gasoline Service Stations; Stage 1: Submerged Filling	--	5.5886	--	4.4738
2501060053	Storage and Transport; Petroleum and Petroleum Product Storage; Gasoline Service Stations; Stage 1: Balanced Submerged Filling	--	0.2157	--	0.1726

SCC	SCC Description	2017 (tpd)		2026 (tpd)	
		NOX	VOC	NOX	VOC
2501060201	Storage and Transport; Petroleum and Petroleum Product Storage; Gasoline Service Stations; Underground Tank: Breathing and Emptying	--	1.0519	--	0.8421
2501080050	Storage and Transport; Petroleum and Petroleum Product Storage; Airports : Aviation Gasoline; Stage 1: Total	--	0.3451	--	0.3320
2501080100	Storage and Transport; Petroleum and Petroleum Product Storage; Airports : Aviation Gasoline; Stage 2: Total	--	0.0004	--	0.0004
2505030120	Storage and Transport; Petroleum and Petroleum Product Transport; Truck; Gasoline	--	0.0706	--	0.0588
2505040120	Storage and Transport; Petroleum and Petroleum Product Transport; Pipeline; Gasoline	--	0.1018	--	0.0839
2610000500	Waste Disposal, Treatment, and Recovery; Open Burning; All Categories; Land Clearing Debris (use 28-10-005-000 for Logging Debris Burning)	0.1672	0.4723	0.1672	0.4723
2610030000	Waste Disposal, Treatment, and Recovery; Open Burning; Residential; Household Waste (use 26-10-000-xxx for Yard Wastes)	0.0188	0.0196	0.0188	0.0196
2630020000	Waste Disposal, Treatment, and Recovery; Wastewater Treatment; Public Owned; Total Processed	--	0.0757	--	0.0896
2680003000	Waste Disposal, Treatment, and Recovery; Composting; 100% Green Waste (e.g., residential or municipal yard wastes); All Processes	--	0.7757	--	0.7757
2805002000	Miscellaneous Area Sources; Agriculture Production - Livestock; Beef cattle production composite; Not Elsewhere Classified	--	0.0019	--	0.0019
2805007100	Miscellaneous Area Sources; Agriculture Production - Livestock; Poultry Waste; Poultry Production - Layers with Dry Manure Management Systems: Confinement	--	<0.0001	--	<0.0001
2805009100	Miscellaneous Area Sources; Agriculture Production - Livestock; Poultry production - broilers; Confinement	--	<0.0001	--	<0.0001
2805010100	Miscellaneous Area Sources; Agriculture Production - Livestock; Poultry production - turkeys; Confinement	--	<0.0001	--	<0.0001

SCC	SCC Description	2017 (tpd)		2026 (tpd)	
		NOX	VOC	NOX	VOC
2805018000	Miscellaneous Area Sources; Agriculture Production - Livestock; Dairy cattle composite; Not Elsewhere Classified	--	<0.0001	--	<0.0001
2805025000	Miscellaneous Area Sources; Agriculture Production - Livestock; Swine production composite; Not Elsewhere Classified (see also 28-05-039, -047, -053)	--	<0.0001	--	<0.0001
2805035000	Miscellaneous Area Sources; Agriculture Production - Livestock; Horses and Ponies Waste Emissions; Not Elsewhere Classified	--	0.0003	--	0.0003
2805040000	Miscellaneous Area Sources; Agriculture Production - Livestock; Sheep and Lambs Waste Emissions; Total	--	<0.0001	--	<0.0001
2805045000	Miscellaneous Area Sources; Agriculture Production - Livestock; Goats Waste Emissions; Not Elsewhere Classified	--	<0.0001	--	<0.0001
2810025000	Miscellaneous Area Sources; Other Combustion; Residential Grilling (see 23-02-002-xxx for Commercial); Total	0.0362	0.0960	0.0429	0.1138
2810060100	Miscellaneous Area Sources; Other Combustion; Cremation; Humans	0.0048	0.0004	0.0056	0.0005
2810060200	Miscellaneous Area Sources; Other Combustion; Cremation; Animals	<0.0001	<0.0001	<0.0001	<0.0001
Totals		6.9445	57.7641	7.1522	61.7171

[a] AIM Coatings SCCs

Appendix B Architectural and Industrial Maintenance (AIM) Coatings: VOC Content Limits

Appendix B Architectural and Industrial Maintenance (AIM) Coatings: VOC Content Limits

Table B1. OTC Model Rule Phase I and Phase II VOC Content Limits for AIM Coatings.

Coating Category	VOC Content Limit (grams per liter) Phase I[1]	VOC Content Limit (grams per liter) Phase II[2]
Flat Coatings	100	50
Nonflat Coatings	150	100
Nonflat – High Gloss Coatings	250	150
Specialty Coatings		
Aluminum Roof	N/A	450
Antenna Coatings	530	N/A
Antifouling Coatings	400	N/A
Basement Specialty Coatings	N/A	400
Bituminous Roof Coating	300	270
Bituminous Roof Primers	350	350
Bond Breakers	350	350
Calcimine Recoaters	475	475
Clear Wood Coatings		
• Clear Bushing Lacquers	680	N/A
• Conversion Varnishes	725	
• Lacquers (including lacquer sanding sealers)	550	
• Sanding Sealers (other than lacquer sanding sealers)	350	
• Varnishes	350	
Concrete Curing Compounds	350	350-
Concrete/Masonry	N/A	100
Concrete Surface Retarders	780	780
Conjugated Oil Varnishes	N/A	450
Conversion Varnish	725	725
Driveway Sealers	N/A	50
Dry Fog Coatings	400	150
Faux Finishing Coatings	350	350
Fire Resistive Coatings	350	350

Coating Category	VOC Content Limit (grams per liter) Phase I[1]	VOC Content Limit (grams per liter) Phase II[2]
Fire Retardant Coatings		
• Clear	650	N/A
• Opaque	350	
Floor Coatings	250	100
Flow Coatings	420	N/A
Form-Release Compounds	250	250
Graphic Arts Coatings (Sign Paints)	500	500
High Temperature Coatings	420	420
Impacted Immersion Coatings	780	780
Industrial Maintenance Coatings	340	250
Low-Solids Coatings	120	120
Magnesite Cement Coatings	450	450
Mastic Texture Coatings	300	100
Metallic Pigmented Coatings	500	500
Multi-Color Coatings	250	250
Nuclear Coatings	450	450
Pre-Treatment Wash Primers	420	420
Primers, Sealers, and Undercoaters	200	100
Quick-Dry Enamels	250	N/A
Quick-Dry Primers, Sealers, and Undercoaters	200	N/A
Reactive Penetrating Sealer	N/A	350
Reactive Penetrating Carbonate Stone Sealer	N/A	500
Recycled Coatings	250	250
Roof Coatings	250	250
Rust Preventative Coatings	400	250
Shellacs		
• Clear	730	730
• Opaque	550	550

Coating Category	VOC Content Limit (grams per liter) Phase I[1]	VOC Content Limit (grams per liter) Phase II[2]
Specialty Primers, Sealers, and Undercoaters	350	100
Stains	250	250
Stone Consolidant	N/A	450
Swimming Pool Coatings	340	340
Swimming Pool Repair and Maintenance Coatings	340	N/A
Temperature-Indicator Safety Coatings	550	N/A
Thermoplastic Rubber Coatings and Mastics	550	550
Traffic Marking Coatings	150	100
Tub and Tile Refinish	N/A	420
Waterproofing Membranes	N/A	250
Waterproofing Sealers	250	N/A
Waterproofing Concrete/Masonry	400	N/A
Wood Coatings	N/A	275
Wood Preservatives	350	350
Zinc-Rich Primer	N/A	340

[1] N/A for Phase I limits indicates that the relevant source category was not controlled as part of the OTC Phase I rule, or several limits from Phase I were combined into a new source category for Phase II

[2] N/A for Phase II limits indicates that the relevant source category emission limit was not included in Phase II, because it was combined into a new source category (e.g., Clear Wood Coatings were controlled at separate limits in Phase I and all combined in Wood Coatings with one limit in Phase II)

Table B2. SCAQMD Rule 1113 VOC Limits as of February 5, 2016.

Coating Category	Current Limit[1]	Effective Date			Small Container Exemption
		1/1/2014	2/5/2016	1/1/2019	
Bond Breakers	350				✓
Building Envelope Coatings	100			50	✓
Concrete-Curing Compounds	100				✓
Concrete-Curing Compounds (For Roadways and Bridges[2])	350				✓[3]
Concrete Surface Retarder	50	50			✓
Default	50	50			✓

Coating Category	Current Limit[1]	Effective Date			Small Container Exemption
		1/1/2014	2/5/2016	1/1/2019	
Driveway Sealer	50				✓
Dry-Fog Coatings	50	50			✓
Faux Finishing Coatings					
• Clear Topcoat	100	100			✓
• Decorative Coatings	350				✓
• Glazes	350				✓
• Japan	350				✓
• Trowel Applied Coatings	50	50			✓
Fire-Proofing Coatings	150	150			✓
Flats	50				✓[5]
Floor Coatings	50				✓
Form Release Compound	100	100			✓
Graphic Arts (Sign) Coatings	200	150	200		✓
Industrial Maintenance (IM) Coatings	100				✓[5]
• Color Indicating Safety Coatings	480				✓[5]
• High Temperature IM Coatings	420				✓[5]
• Non-Sacrificial Anti-Graffiti Coatings	100				✓[5]
• Zinc-Rich IM Primers	100				✓[5]
Magnesite Cement Coatings	450				✓[3]
Mastic Coatings	100	100			✓
Metallic Pigmented Coatings	150	150			✓
Multi-Color Coatings	250				✓[3]
Nonflat Coatings	50				✓[5]
Pre-Treatment Wash Primers	420				✓[3]
Primers, Sealers, and Undercoaters	100				✓
Reactive Penetrating Sealers	350				✓[4]
Recycled Coatings	250			150	✓
Roof Coatings	50				✓
• Roof Coatings, Aluminum	100				✓
Roof Primers, Bituminous	350				✓[3]
Rust Preventative Coatings	100				✓[6]
Sacrificial Anti-Graffiti Coatings	50				✓[3]
Shellac					

Coating Category	Current Limit[1]	Effective Date			Small Container Exemption
		1/1/2014	2/5/2016	1/1/2019	
• Clear	730				✓[4]
• Pigmented	550				✓[4]
Specialty Primers	100				✓
Stains	100				✓
• Stains, Interior	250				✓
Stone Consolidants	450				✓[3]
Swimming Pool Coatings					
• Repair	340				✓[3]
• Other	340				✓[3]
Tile and Stone Sealers	100				✓
Traffic Coatings	100				✓
Tub and Tile Refinishing Coatings	420				✓[4]
Waterproofing Sealers	100				✓
Waterproofing Concrete/Masonry Sealers	100				✓
Wood Coatings	275				
• Varnish	275				
• Sanding Sealers	275				
• Lacquer	275				
Wood Conditioners	100				
Wood Preservatives					
• Below-Ground	350				✓[3]
• Other	350				✓[3]
Low-Solids Coating	120				
Architectural Coatings, excluding IM Coatings	50				
Solvent-Based IM	600				
Waterborne IM	50				

[1] The specified limits remain in effect unless revised limits are listed in subsequent columns in the Table of Standards.
[2] Does not include compounds used for curbs and gutters, sidewalks, islands, driveways and other miscellaneous concrete areas.
[3] Effective 02/05/2016, the small container exemption no longer applies per (f)(1).
[4] Effective 01/01/2018, the small container exemption no longer applies per (f)(1).
[5] Effective 01/01/2018, the small container exemption is further restricted per (f)(1).
[6] Effective 01/01/2018, the small container exemption is further restricted per (f)(1).

ATTACHMENT H:

Inspection/Maintenance Program Effectiveness Study

PARSONS

Final Report

Evaluation of the Effectiveness of the Clark County Vehicle Inspection and Maintenance Program

December 13, 2002
Submitted in compliance with the requirements of
CBE Number 1746-02; Contract for Consulting Services for Decentralized Vehicle Inspection and Maintenance Program Analysis

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Executive Summary

On behalf of the Clark County Department of Air Quality Management (DAQM), Parsons, on July 16, 2002, initiated an analysis to determine the emission reductions achieved by test-only and test-and-repair stations participating in the inspection and maintenance (I/M) program. The goal of the analysis is the determination of the comparative effectiveness of test-and-repair and test-only stations in identifying and reducing Carbon Monoxide (CO) emissions of tested motor vehicles.

In accordance with the guidance documentation developed by the United States Environmental Protection Agency (USEPA) in 1992, the existing State Implementation Plan (SIP) filed in 1996, discounted by 50 percent all of the excess CO emissions benefits generated by the County's I/M program. The USEPA performed numerous studies in several states showing that a substantially higher number of fraudulent emission tests occur at inspection stations that perform both emissions tests and vehicle repairs. Based on these studies, the USEPA required states to discount emissions benefits generated at test-and-repair stations by 50 percent. However, the USEPA allows 100 percent credit for emissions reduced on vehicles inspected at test-only stations.

The analysis used emission results from motor vehicles failing their emissions test for the period from July 1, 2001 through June 30, 2002. The analysis uses these test results to determine if the emissions reduced on after-repairs tests at test-and-repair stations are equivalent to emissions benefits generated by test-only stations. Parsons used Microsoft Excel and standard statistical tools and methods to analyze the data. The analysis includes both parametric and nonparametric statistical analyses. The analysis includes calculation of the overall average reductions of CO emissions and the average reductions for each vehicle model-year category.

Based on the data analysis contained in this evaluation, test-and-repair stations are equally as effective as test-only stations at reducing emissions. Therefore, the input for the I/M effectiveness rate in the MOBILE6 model for the I/M program in Clark County should be 100 percent.

Acronyms

CO – Carbon Monoxide
CFR – Code of Federal Regulations
DAQM – Clark County Department of Air Quality Management
DMV – Nevada Department of Motor Vehicles
DTC – Diagnostic Trouble Codes are generated by the vehicle's on-board diagnostic computer to assist a technician in locating problems with emissions-related engine/vehicle components
GVWR – Gross Vehicle Weight Rating
I/M – Vehicle Inspection and Maintenance Program
MOBILE6 – USEPA computer model used to generate emission factors for making decisions about air quality program strategies designed to reduce emissions from vehicles
NHSDA – National Highway System Designation Act of 1995
OBD – On-Board Diagnostic computer systems designed to monitor and manage critical engine emission controls and operating parameters
RPM – Revolutions Per Minute allowed on emissions tests
SIP – State Implementation Plan
TSI – Two-speed Idle Test to measure vehicle emissions
USEPA – United States Environmental Protection Agency
VID – Vehicle Identification Database storing vehicle emissions inspection results
VIN – Vehicle Identification Number

Introduction

The United States Environmental Protection Agency (USEPA) indicates that motor vehicles are the source of more than 90 percent of the Carbon Monoxide (CO) pollution in urban areas[1]. As a result, the USEPA promotes the use of vehicle inspection and maintenance (I/M) programs as one of the major strategies to address excess vehicle emissions.

Clark County implemented a pilot I/M program in 1974. In 1983, the I/M program became mandatory, requiring CO emission tests for motor vehicles. The Clark County I/M program is a decentralized, registration-based program (i.e., inspections performed at privately-owned, state licensed stations), requiring annual inspections, using a USEPA-approved two-speed idle (TSI) test measuring CO emissions at idle and 2500 RPM. In 1999, the program began converting all stations to an electronic data transmission system. All of these program features remain today. The program consists of two types of emissions inspection stations:

- Test-only stations that only perform emissions inspections; and
- Test-and-repair stations that perform both emissions inspections and motor vehicle repairs.

The USEPA uses a computer model (MOBILE6) to calculate current and future emission factors for motor vehicles based on various inputs including changes in emission standards, vehicle fleet characteristics, and environmental conditions. Past policy only allowed partial credit for model defaults to I/M programs utilizing private test-and-repair stations to perform vehicle emissions inspections. Currently, unless states petition the USEPA and supply a justification for additional credit, only 50 percent of the credit granted to programs utilizing privately or publicly operated test-only stations is allowed for a program utilizing test-and-repair stations.

On behalf of the Clark County Department of Air Quality Management (DAQM), Parsons completed an independent assessment of the emissions test data collected as part of the current motor vehicle I/M program in Clark County. This evaluation, based on the analysis of those emissions test results, seeks to quantify the appropriate effectiveness rate for test-and-repair stations and a combined I/M effectiveness rate to use in the MOBILE6 model for the I/M program in Clark County.

The following sections provide background information about the I/M program, the data analysis performed to determine the effectiveness rates, and the conclusions drawn from that analysis.

[1] EPA 400-F-92-005, January 1993 OMS Fact Sheet #3

Background for the Analysis

Program Background

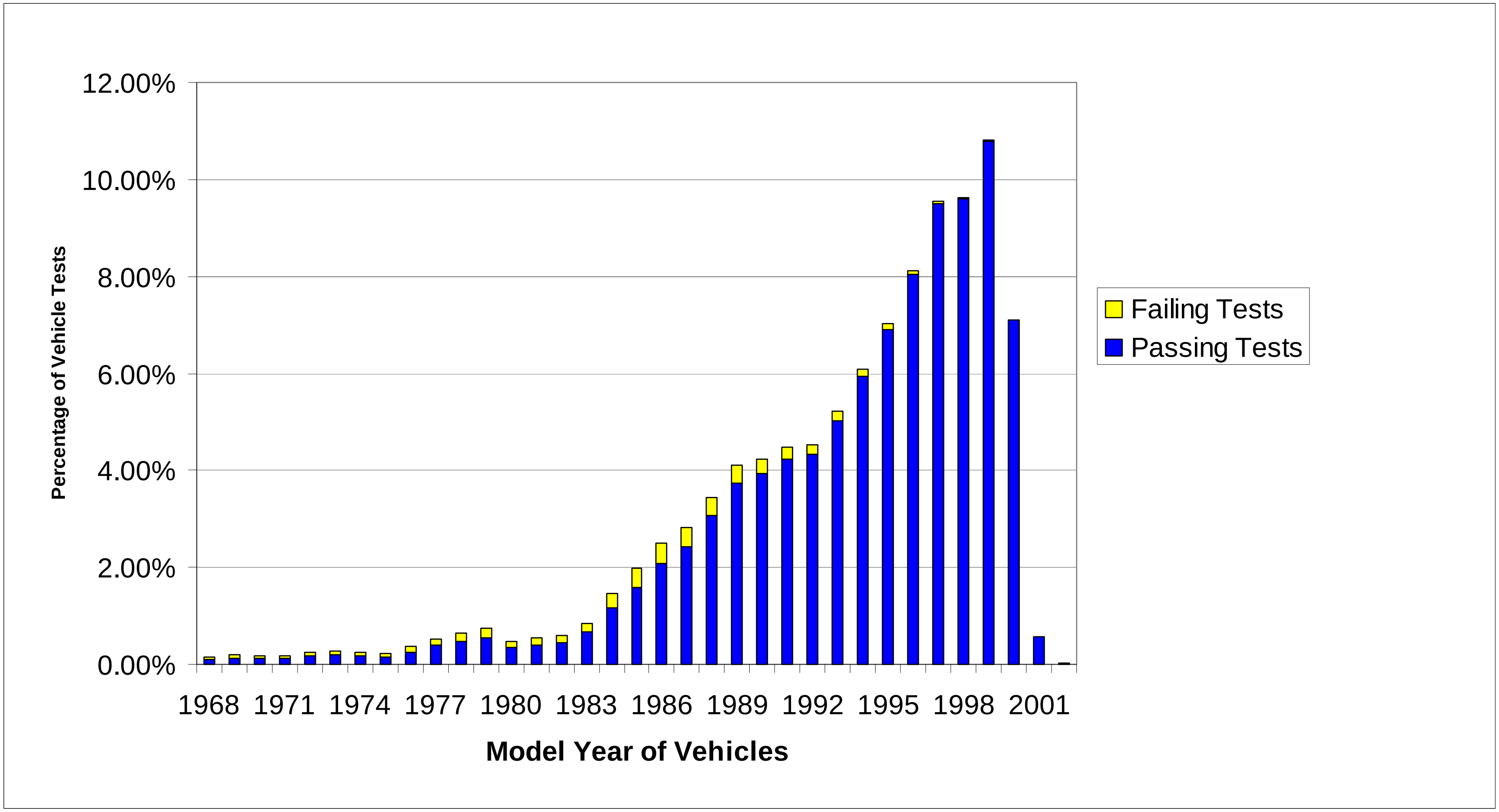
The Nevada Department of Motor Vehicles (DMV) operates the statewide vehicle inspection and maintenance (I/M) program. The DMV's Mission Statement reads in part: "Our mission is to …assist Nevada in meeting its federally mandated air quality standards." The vehicle inspection program affects vehicles located in Clark County meeting the following criteria:

- Gasoline powered;
- Diesel powered with a gross vehicle weight under 8,500 pounds; and
- 1968 model-year or newer.
  (new vehicles on their first or second registration are exempted; a test is required upon a vehicle's third registration)

Vehicle emission inspection certificates are required for registration on an annual basis. Vehicles with model years between 1968 and 1995 are administered an idle and 2500 RPM test. The common name of this test is the two-speed idle test (TSI). The USEPA developed the two-speed idle test in the late 1970's and early 1980's. Studies show that the 2500-RPM test capably identifies excess CO emissions resulting from high-speed misfires. 1996 and newer model year vehicles may receive either the TSI test or the new On-Board Diagnostics (OBD) test in 2002. In 2003, the OBD test becomes mandatory for all 1996 and newer vehicles. The On-Board Diagnostics (OBD) test checks diagnostic trouble codes (DTC) generated by the vehicle's on-board computer sensor system. Nevada emissions stations gradually implemented OBD testing throughout 2002.

Figure 1 shows the distribution by model year of the total initial tests, and the passing and failing percentages. 94.8 percent of the vehicles participating in the program pass their initial emissions inspection with an overall failure rate of 5.2 percent. However, 20 percent of 1989 and older vehicles fail the initial emissions inspection while only 0.2 percent of 1990 and newer model year vehicles fail.

Figure 1 Distribution by Model Year of Initial Test Results



Failing vehicles must be either repaired or obtain a waiver in order to complete the vehicle registration process. In Clark County, vehicle owners that cannot obtain the repairs required to make their vehicle meet emissions standards, may apply for a waiver. Vehicle owners must supply receipts from a licensed station showing that they have spent a minimum of $450 on emission related repairs other than the replacement of the catalytic converter, fuel inlet restrictor or air injection system to qualify for a waiver. The waiver process cannot certify smoking vehicles or vehicles eligible for warranty repairs.

Emission inspection stations electronically transmit vehicle emissions test results to the DMV. This allows vehicle registration renewal by mail, over the Internet, by telephone, in person at a DMV office or in the future at participating inspection stations. Vehicle owners receive a printed emissions inspection report at the conclusion of the inspection for their records. The electronic data transmission system provides a number of other benefits besides convenience for vehicle owners. The system allows the DMV to monitor operations at stations in real-time, produces a number of standardized reports on the program, assists the department in evaluating program performance, and identifies potential enhancements to the system.

USEPA I/M Program Requirements

Title 40 Section 51 of the Code of Federal Regulations (CFR) contains the regulations for Inspection and Maintenance (I/M) programs. The I/M program used by Clark County is a decentralized hybrid program that includes both test-only and test-and-repair stations. Clark County is subject to the Alternate Low Enhanced I/M Performance Standard of Subsection 51.352 (g) of Title 40 of the Code of Federal Regulations. While the foregoing Subsection requires that testing be a centralized network, Subsection 51.353 (a) of Title 40 CFR allow for presumptive equivalency and states: “A decentralized network consisting of stations that only perform official I/M testing (which may include safety-related inspections) and in which owners and employees of those stations, or companies owning those stations, are contractually or legally barred from engaging in motor vehicle repair or service, motor vehicle parts sales, and motor vehicle sale and leasing, either directly or indirectly, and are barred from referring vehicle owners to particular providers of motor vehicle repair services (except as provided in § 51.369(b)(1) of this subpart), shall be considered presumptively equivalent to a centralized, test-only system including comparable test elements.” Regarding programs that permit facilities to engage in motor vehicle repair or service, motor vehicle parts sales, and motor vehicle sales and leasing, either directly or indirectly, Section 51.353 of Title 40 CFR, states: “For decentralized programs other than those meeting the design characteristics described in paragraph (a) of this section, the State must demonstrate that the program is achieving the level of effectiveness claimed in the plan within 12 months of the plan’s final conditional approval before EPA can convert that approval to a final full approval. The adequacy of these demonstrations will be judged by the Administrator on a case-by-case basis through notice-and-comment rulemaking.”

Clark County has a hybrid program, which includes both test-and-repair and test-only stations. The USEPA revised their regulations in 1995, 1996, 1999 and 2000 to provide additional flexibility to states regarding the various alternative program designs and to recognize hybrid programs. The initial modifications, made in 1995, resulted from the passage of the National Highway System Designation Act (NHSDA). Congress felt that the States should receive additional flexibility regarding implementation of their I/M programs and prohibited the USEPA from applying any automatic discounts to emission benefits based strictly on the type of program.

Based on Subsection 51.353 (a) of the Title 40 CFR, Clark County's test-only stations have the presumption of equivalency to a centralized test network and should receive the same emission reduction credits as a centralized system. In addition, Section 51.353 of Title 40 CFR allows the test and repair station component to receive the same credit if it demonstrates that those types of facilities achieve the same level of effectiveness as the test-only stations.

On January 29, 2002, the USEPA announced the approval and availability of the MOBILE6 model for use by state and local governments to meet Clean Air Act requirements[2]. The MOBILE6 model calculates current and future emission factors of motor vehicle emissions. Air pollution programs use the emission factors to make decisions about policies and meet SIP requirements. The model accounts for the emission impacts of factors such as changes in vehicle emission standards, vehicle populations, and changes in local environmental conditions. MOBILE6 is a major revision to the MOBILE model and it provides more options for users to incorporate local inputs. Unlike previous versions of the model, users can now adapt the model to local conditions and special situations that are not reflected in the model's default settings. For I/M programs with test-and-repair stations, states must specify effectiveness rates for the program. Because the 1995 NHSDA allows states to make a demonstration of effectiveness, states should consult with the USEPA regarding appropriate levels of effectiveness for the local I/M program[3].

This analysis of emission test results provides a means to quantify the appropriate effectiveness rate for the state I/M program in Clark County. It does this through a comparative analysis of the emissions reductions achieved by the test-and-repair and test-only emissions inspection stations located in the Las Vegas Valley.

[2] The Federal Register, Volume 67, Number 19, Notices, Tuesday, January 29, 2002.
[3] Page 66, Section 6.11, Technical Guidance on the Use of MOBILE6 for Emission Inventory Preparation, USEPA, Office of Air and Radiation, Office of Transportation and Air Quality, January, 2002.

Methodology

The Nevada Department of Motor Vehicles (DMV) provided the set of emissions inspection data analyzed in this report. Parsons used pre- and post-repair inspection data from that data set to compare and evaluate the effectiveness of repairs made on vehicles failed at test-only and test-and-repair emissions inspection stations. The differences between the initial and the after-repairs tests indicate the level of emission benefits obtained by each type of station.

The analysis contained two steps: “Development of a Protocol to Perform the Analysis” and “Data Analysis.”

Development of a Protocol to Perform the Analysis

DMV Data Set

Parsons provided data specifications (see Appendix B) to the DMV. Parsons received the data in an electronic format for the analysis from the DMV’s Vehicle Identification Database (VID).

The data specifications outlined the fields needed to perform the analysis. Vehicle test records contained the following fields:

- Facility identification information indicating whether the facility is a test-only or a test-and-repair station;
- Vehicle license plate and Vehicle Identification Number (VIN);
- Vehicle type, Gross Vehicle Weight (GVWR), model year, make and model;
- Test type (i.e., initial, after-repair or waiver);
- Test date and time;
- Emission standards category and cut points;
- Pre-repair idle test results for CO;
- Pre-repair 2500-RPM test results for CO;
- Repair information;
- Post-repair idle test results for CO;
- Post-repair 2500-RPM test results and CO; and
- Pass/Fail result.

Parsons analyzed only vehicle test records meeting the following criteria:

- 1968 and newer light-duty vehicles that failed an initial emissions inspection and had a post-repair emissions inspection performed at the same type of station (i.e., either a test-only or test-and-repair station);
- Gasoline powered; and
- Vehicles registered within Clark County.

Parsons also requested information delineating the model-year distribution of the overall fleet in Clark County and the numbers for each model-year category subject to the program.

Protocol

The data analysis used Microsoft Excel and the following rules for the analysis:

- The analysis used only initial and after-repair test records that were both performed at either a test-only or a test-and-repair station.
- For vehicles that are given multiple initial inspections, the analysis used the oldest initial test within 90-days prior to the vehicle receiving a certificate. Many times, vehicle owners perform their own repairs and take the vehicle to a different inspection facility for another inspection. This looks like a second initial test in the database. Parsons sorted the data by the VIN and the date/time to find the correct initial test, regardless of where the inspection was performed as long as it was at the same type of station;
- For vehicles given multiple after-repair tests, the analysis used only the final emission test results;
- DMV's contractor, WorldCom, performed a quality assurance check of the data fields and Parsons performed additional checks for bad records during the analysis. Bad test records usually result from missing fields and misaligned data entries. For unsalvageable records, Parsons removed those records from the data set. However, while no records lacked critical information, some records contained blanks and/or inaccurate characters. To maximize the number of vehicle records included in the analysis, Parsons used the test records if both the pre- and post-repair emission results had a matching VIN at the same type of station.
- Exclusion of undercover vehicle test records, or records for issued waivers from the data set analyzed. Parsons requested removal of those records from the data set before shipment of the data to Parsons. The DMV's contractor confirmed they excluded those records; and
- To match the test records, Parsons used the VIN and license number on each vehicle to identify the first initial test and final after-repairs test. The analysis excluded intermediate tests (i.e., multiple initial or after-repair tests between the first initial and final after-repairs inspection).

Data Analysis

Parsons performed an analysis of the emission test results and provided the following:

- Proportion of emissions tests conducted by station type;
- Average CO reductions achieved:
  - o For each type of station; and
  - o For different model year vehicles.
- Categorization of station performance; and
- Combined I/M program effectiveness (between 50 – 100 percent);

After sorting the vehicle test by station type and VIN, Parsons took the difference between the first test and last post-repair test listed for each vehicle to average the CO emissions for the idle and 2500-RPM tests for each vehicle model-year category. Based on the amount of emissions reduced, Parsons calculated the effectiveness of repairs made on vehicles that had failed at test-only stations compared to vehicles failed at test-and-repair stations in the program. Appendix C contains a description of the detailed analysis steps for each of the deliverables.

The analysis used vehicle test records for the period of July 1, 2001 to June 30, 2002. Below is a description of the analysis for each of the items requested in the contract.

Proportion of Emissions Tests by Station Type

As of October 2002, 94 test-only and 159 test-and-repair stations participate in the I/M program in Clark County. Although only 37 percent of the inspection facilities are test-only stations, they perform 57.5 percent of the total tests. Test-and-repair stations make up 63 percent of the facilities in the County and perform 42.5 percent of the emissions tests. Table 1 below shows that of the total number of vehicles failing emission tests, 59.7 percent of the failed vehicles are initially tested at test-only stations and 40.3 percent at test-and-repair stations.

Table 1 Volume of Initial Tests, Percent Failures and Number of Stations

Station Type	Number of Stations	Total Initial Tests	Percent	Number of Initial Failures	Percent
Test-Only	94	469,676	57.5	37,732	59.7
Test-and-Repair	159	347,749	42.5	25,512	40.3

Table 2 shows the failure rate of vehicles inspected at each of the two types of stations. The failure rates are between two and three percent higher than the initial failure rate shown in Figure 1 because the overall percentage includes retests. The difference in percentage of vehicles failed at each type of station is less than one percent. This indicates that in Clark County emissions reductions achieved by test-and-repair stations are comparable to those achieved by test-only stations.

Table 2 Failure Rate by Station Type

Station Type	Total Test Volume	Number of I/M Failures	Percent Failed
Test-Only	469,676	37,732	8.0
Test-and-Repair	347,749	25,512	7.3

The historical test data shown in Table 3 below for fiscal years 2000-2001 and 2001-2002 indicate increasing inspection volumes for test-only stations since 2001. Test-only stations on average performed 57 percent of the emission tests both of the subject fiscal years.

Table 3 Historical Test Volumes by Station Type

Fiscal Quarter	Total Tests	Test-Only	Percent Test-Only	Test-and-Repair	Percent Test-and-Repair
Jul-Sept, 00	196,751	107,761	55	88,989	45
Oct-Dec, 00	178,323	97,437	55	80,885	45
Jan-Mar, 01	209,839	115,493	55	94,345	45
Apr-Jun, 01	208,646	116,064	56	92,581	44
Jul-Sept, 01	209,467	122,889	59	86,577	41
Oct-Dec, 01	192,710	111,633	58	81,076	42
Jan-Mar, 02	214,874	126,517	59	88,356	41
Apr-Jun, 02	219,389	131,678	60	87,711	40

Average Reductions Achieved for Each Type of Station

Parsons sorted the DMV data by the vehicle identification number (VIN), and the date and time of the inspection for each type of station (i.e., test-only and test-and-repair). Parsons calculated the reductions by subtracting the first test from the last for each set of matching test records, summing the emissions and dividing by the number of vehicles for the station type. The number of retests on failing vehicles ranged from one to seven inspections. Table 4 below shows the average CO emissions reduced by station type.

Table 4 Average Emissions Reductions per Vehicle by Station Type

Station Type	Average Idle Test CO Emission Reduction (% by Volume)	Average 2500 RPM Test CO Emission Reduction (% by Volume)
Test-Only	2.12	1.76
Test-and-Repair	2.16	1.92

The results shown in Table 4 include vehicles without a passing test record in the analysis period. Reasons for this include destruction of the vehicles or relocation of the vehicle out of the program area. Also, some vehicle owners have difficulties paying for needed emissions repairs or they may be planning on selling the vehicle in the near future. To provide a reference point, Parsons did some additional analysis on the data set with these vehicles removed. Table 5 below contains that data for comparative purposes.

Table 5 Average Emission Reductions per Vehicle by Station Type for Passing Vehicles

Station Type	Average Idle Test CO Emission Reduction (% by Volume)	Average 2500 RPM Test CO Emission Reduction (% by Volume)
Test-Only	2.20	1.84
Test-and-repair	2.20	1.96

When these vehicles are removed from the data set, the average reductions are identical for the idle test and closer on the 2500 RPM test. This demonstrates that both types of stations are reducing emissions significantly, and the test-and-repair stations on average are achieving higher emissions reductions.

Average Reductions Achieved for Different Model-Year Vehicles

The model-year grouping selections reflect changes in emission control applications and/or balance the volume of tests in each category. The model-year categories of 1968-74 and 1975-79 reflect the initial installation of catalytic converters starting in 1975, and the initiation of the 3-way catalyst and feedback control systems in 1980. For the 1980-85, 1986-89, and 1990-95, the categories primarily reflect an effort to balance the volume.

A separate category created for the 1996 and newer vehicles reflect the introduction of the second-generation of on-board diagnostic (OBDII) systems. Early in 2002, the USEPA authorized states to perform a check of the OBDII systems instead of the TSI emissions test. The OBDII check can be performed more quickly on late model vehicles where the standardized OBD connector is readily accessible.

The largest category is the 1986-89 category; the next two largest model-year categories are the 1990-1995 and 1980-1985 categories respectively.

Table 6 shows the volume of vehicles that failed I/M tests in each model-year category described above for test-only and test-and-repair stations.

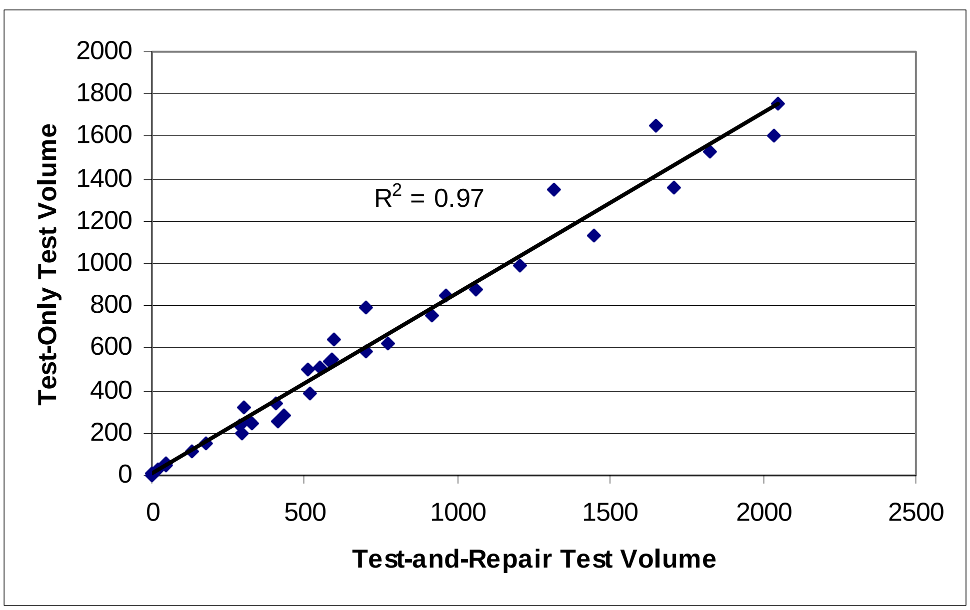
Table 6 Volume of I/M Failures by Model Year Categories

Station Type	1968-74	1975-79	1980-85	1986-89	1990-95	1996+	Total
Test-Only	2,475	3,494	5,423	7,611	5,457	419	**24,879**
Test-and-Repair	1,816	3,044	5,519	6,249	4,475	397	**21,500**
Total	4,291	6,538	10,942	13,860	9,932	816	**46,379**

Table 7, shown on the following page, contains a tabulation of the volume of failed vehicles by model year and station type[4]. The means and standard deviations of the two distributions differ, but the correlation coefficient of 0.97 indicates an extremely good correlation. Figure 2 contains the regression line.

Figure 2 shows the data points grouped tightly around the regression line. Some differences between the volumes of older vehicles tested at test-only and test-and-repair stations do exist, but the differences are relatively small compared to the newer model-year categories. Therefore, the difference in the volume of older cars tested at each type of station has little effect on the overall correlation coefficient.

Figure 2 Regression of Test-Only and Test-and-Repair Volumes by Model Year Category



[4] The percentage of tests performed at the test-only and test-and-repair stations shown in Table 7 are slightly different from those shown in Table 1 because Table 8 includes retests.

Table 7 Volume of Test Failures by Model Year and Station Type

Model Year	Number of Vehicles Failed at Test-Only Stations	Percentage of Vehicles Failed at Test-Only Stations	Number of Vehicles Failed at Test-and-Repair Stations	Percentage of Vehicles Failed at Test-and-Repair Stations	Total Number of Vehicles Failed
1968	294	0.6%	202	0.4%	496
1969	322	0.7%	257	0.6%	579
1970	325	0.7%	249	0.5%	574
1971	287	0.6%	233	0.5%	520
1972	434	0.9%	281	0.6%	715
1973	403	0.9%	338	0.7%	741
1974	410	0.9%	256	0.6%	666
1975	302	0.7%	320	0.7%	622
1976	513	1.1%	502	1.1%	1015
1977	700	1.5%	583	1.3%	1283
1978	916	2.0%	757	1.6%	1673
1979	1063	2.3%	882	1.9%	1945
1980	580	1.3%	534	1.2%	1114
1981	585	1.3%	549	1.2%	1134
1982	594	1.3%	638	1.4%	1232
1983	701	1.5%	794	1.7%	1495
1984	1313	2.8%	1351	2.9%	2664
1985	1650	3.6%	1653	3.6%	3303
1986	2049	4.4%	1753	3.8%	3802
1987	2035	4.4%	1605	3.5%	3640
1988	1822	3.9%	1532	3.3%	3354
1989	1705	3.7%	1359	2.9%	3064
1990	1447	3.1%	1128	2.4%	2575
1991	1207	2.6%	986	2.1%	2193
1992	963	2.1%	852	1.8%	1815
1993	773	1.7%	618	1.3%	1391
1994	548	1.2%	505	1.1%	1053
1995	519	1.1%	386	0.8%	905
1996	178	0.4%	148	0.3%	326
1997	134	0.3%	112	0.2%	246
1998	43	0.1%	49	0.1%	92
1999	44	0.1%	56	0.1%	100
2000	18	0.0%	27	0.1%	45
2001	2	0.0%	5	0.0%	7
2002					
	24879	**54%**	**21500**	**46%**	**46379**

As shown in Figure 3 below, test-only stations tested more vehicles in the 1968-74 model-year category than did test-and-repair stations. However, the greatest number of tests at both types of station occurs for 1985-92 model-year vehicles.

Figure 3 Vehicle Failure Rate by Model Year and Station Type

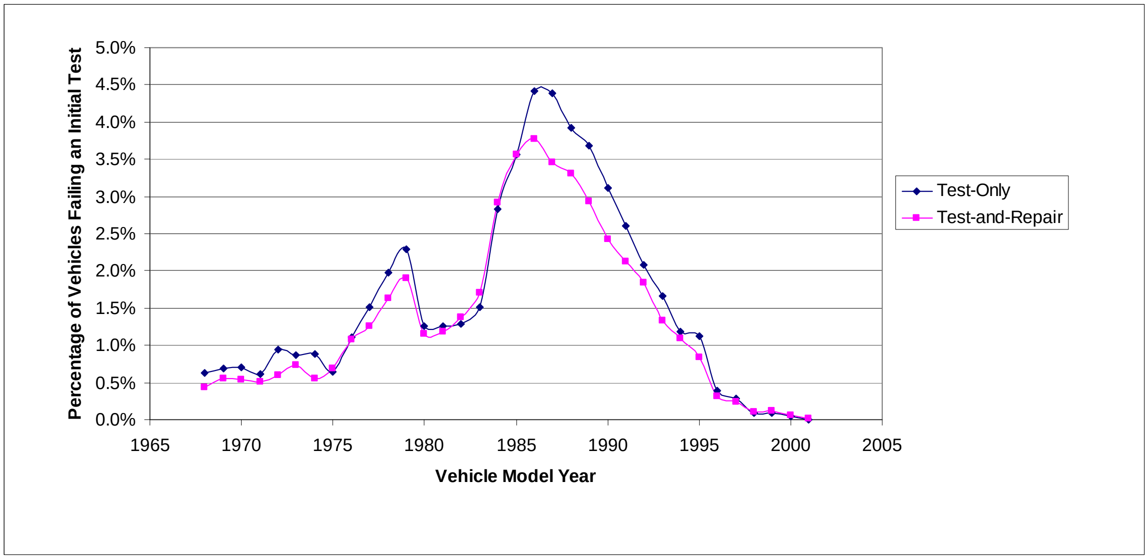


Table 8 shows the difference between the idle and the 2500-RPM CO emission reductions for test-only and test-and-repair stations by model-year category. Overall, the test-and repair stations show higher CO emissions reductions for the idle and the 2500-RPM emissions tests.

Table 8 Average Emissions Reductions by Model Year Category and Station Type

Model Year Category	Average Test-Only Idle CO Reductions (% by Vol.)	Average Test-and-Repair Idle CO Reductions (% by Vol.)	Percent Difference	Average Test-Only 2500 RPM CO Reductions (% by Vol.)	Average Test-and-Repair 2500 RPM CO Reductions (% by Vol.)	Percent Difference
68-74	3.35	2.99	-5.7	1.85	1.68	-4.9
75-79	2.68	2.57	-2.1	1.69	1.71	+0.6
80-85	1.95	2.07	+2.8	1.79	2.16	+9.3
86-89	1.75	1.92	+4.8	1.75	1.94	+5.1
90-95	1.77	1.93	+4.3	1.69	1.83	+4.0
96+	2.74	2.38	-7.0	2.34	2.09	-5.8
Overall	2.12	2.16	+0.7	1.78	1.92	+3.9

For the idle test, the resulting difference between the test-only and test-and-repair stations is less than one percent, and for the 2500-RPM test about 4 percent.

Figure 4 shows the combined average-emissions-reduced for each station type for the idle and 2500-RPM tests by the following method:

- Subtraction of the initial test from the final retest to calculate the emission benefits for each vehicle;
- Summed the emission benefits;
- Calculated the average emissions benefit by dividing the sum of the emissions benefits by the number of vehicles in each model-year category.

This operation included the data for each type of station and each model-year category.

Figure 4 Average Emissions Reduced by Station Type and Model Year for Idle and 2500 RPM Tests Combined

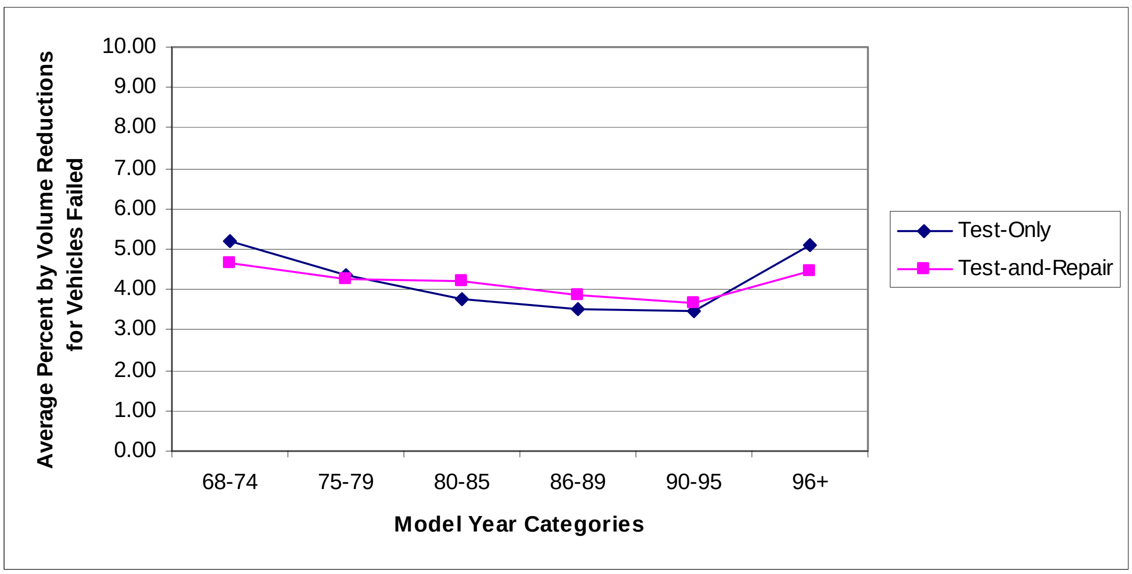


Table 9 shows the overall proportion of CO emissions reduced by station type. Test-only stations reduce emissions slightly more than the test-and-repair stations.

Table 9 Proportion of CO Emissions Reduced by Station Type

Type of Station	Proportion of Emissions Reduced
Test-Only	50.7 %
Test-and-Repair	49.3%

Overall, the test-only stations generate approximately 51 percent of the emission reductions and the test-and-repair stations generate 49 percent of the emission reductions. Although test-and-repair stations reduce more emissions on average, they inspect approximately 122,000 fewer vehicles and they fail about 12,000 less vehicles than the test-only stations as shown in Tables 1 and 2. As a result, the overall proportion of emissions reduced at test-only stations is slightly higher.

Since the proportion of emission reductions achieved by both types of stations are so close to 50 percent, it is clear that they are both making a significant contribution towards reducing excess CO emissions in Clark County.

Categorization of Station Performance

As part of this analysis, Parsons agreed to evaluate the average emissions reduced for all stations and group them into upper, middle and lower categories of performance. The evaluation is contained in Appendix D. Although the analysis is not crucial to the objective of this study (i.e., to identify an I/M effectiveness rate that can be used in the MOBILE6 model for the Clark County I/M program), the information could be useful to the Nevada Department of Motor Vehicles I/M program enforcement staff.

Combined I/M Program Effectiveness

Based on the results of the analysis contained in this report by Parsons, both the test-only and test-and-repair stations play a critical role in reducing nearly equivalent amounts of excess CO emissions in Clark County. The USEPA does not discount the emissions benefits generated at test-only stations, and the data analyzed by Parsons for Clark County indicates that the test-and-repair stations generate nearly the same level of emission benefits as the test-only stations. Therefore, the input for the I/M effectiveness rate in the MOBILE6 emissions model for the I/M program in Clark County should be 100 percent.

Conclusions

After the USEPA released the 1990 Clean Air Act Amendments and promulgated the I/M regulations in the Federal Register, many regulatory agencies, including Clark County, who administered decentralized I/M programs, utilized the default value of 50 percent effectiveness for the emissions reduced by all the stations in their program. 40 CFR, Section 51.353(a) provides that a "…decentralized network consisting of stations that only perform official I/M (test-only stations)…shall be considered equivalent to a centralized, test-only system."

Based on this and the flexibility added by the NHSDA, Clark County should receive 100 percent of credit for the emissions benefits from inspections performed at test-only stations.

The data analysis in this report also indicates that the test-only and test-and-repair stations are equally effective at reducing excess CO emissions and improving air quality in Clark County. Therefore, the input for the I/M effectiveness rate in the MOBILE6 model for the I/M program in Clark County should be 100 percent.

Appendix A Model-Year Distribution of Vehicle Initial Tests in the IM Program During the Analysis Period of Fiscal Year 2001-2002 in Clark County

Model Year	3rd Quarter 2001 Total Initial Tests	3rd Quarter 2001 Initial Passing	3rd Quarter 2001 Initial Failing	3rd Quarter 2001 Failure %	4th Quarter 2001 Total Initial Tests	4th Quarter 2001 Initial Passing	4th Quarter 2001 Initial Failing	4th Quarter 2001 Failure %	1st Quarter 2002 Total Initial Tests	1st Quarter 2002 Initial Passing	1st Quarter 2002 Initial Failing	1st Quarter 2002 Failure %	2nd Quarter 2002 Total Initial Tests	2nd Quarter 2002 Initial Passing	2nd Quarter 2002 Initial Failing	2nd Quarter 2002 Failure %
1968	348	249	99	28.4%	321	239	82	25.5%	164	114	50	30.5%	266	178	88	33.1%
1969	410	295	115	28.0%	424	299	125	29.5%	257	201	56	21.8%	296	202	94	31.8%
1970	448	327	121	27.0%	379	275	104	27.4%	208	152	56	26.9%	315	212	103	32.7%
1971	448	329	119	26.6%	358	260	98	27.4%	201	143	58	28.9%	270	184	86	31.9%
1972	584	449	135	23.1%	554	421	133	24.0%	302	215	87	28.8%	442	297	145	32.8%
1973	685	500	185	27.0%	498	376	122	24.5%	359	279	80	22.3%	453	308	145	32.0%
1974	655	449	206	31.5%	492	368	124	25.2%	301	228	73	24.3%	391	284	107	27.4%
1975	530	357	173	32.6%	456	326	130	28.5%	273	190	83	30.4%	331	238	93	28.1%
1976	923	656	267	28.9%	757	569	188	24.8%	428	320	108	25.2%	566	384	182	32.2%
1977	1310	956	354	27.0%	1122	863	259	23.1%	624	456	168	26.9%	817	588	229	28.0%
1978	1566	1,166	400	25.5%	1279	997	282	22.0%	845	637	208	24.6%	1032	731	301	29.2%
1979	1911	1,441	470	24.6%	1596	1,200	396	24.8%	906	666	240	26.5%	1179	830	349	29.6%
1980	1167	867	300	25.7%	989	760	229	23.2%	596	449	147	24.7%	722	531	191	26.5%
1981	1416	1,072	344	24.3%	1077	832	245	22.7%	632	475	157	24.8%	864	632	232	26.9%
1982	1537	1,146	391	25.4%	1204	948	256	21.3%	754	576	178	23.6%	999	731	268	26.8%
1983	2165	1,729	436	20.1%	1716	1,379	337	19.6%	1016	816	200	19.7%	1426	1,077	349	24.5%
1984	3769	3,040	729	19.3%	2946	2,387	559	19.0%	1826	1,433	393	21.5%	2316	1,791	525	22.7%
1985	5081	4,171	910	17.9%	4001	3,270	731	18.3%	2440	1,954	486	19.9%	3200	2,487	713	22.3%
1986	6531	5,493	1038	15.9%	5042	4,315	727	14.4%	2982	2,471	511	17.1%	4051	3,224	827	20.4%
1987	7307	6,315	992	13.6%	5680	5,001	679	12.0%	3336	2,837	499	15.0%	4623	3,844	779	16.9%
1988	8998	7,998	1000	11.1%	6879	6,205	674	9.8%	4158	3,682	476	11.4%	5577	4,893	684	12.3%
1989	10628	9,797	831	7.8%	8305	7,687	618	7.4%	4879	4,420	459	9.4%	6729	6,000	729	10.8%
1990	10887	10,225	662	6.1%	8390	7,788	602	7.2%	5031	4,666	365	7.3%	7156	6,572	584	8.2%
1991	11550	10,977	573	5.0%	9058	8,581	477	5.3%	5227	4,940	287	5.5%	7565	7,069	496	6.6%
1992	11811	11,364	447	3.8%	9082	8,713	369	4.1%	5239	5,002	237	4.5%	7541	7,122	419	5.6%
1993	13557	13,161	396	2.9%	10393	10,075	318	3.1%	6002	5,775	227	3.8%	8872	8,494	378	4.3%
1994	15909	15,601	308	1.9%	12263	11,998	265	2.2%	6993	6,840	153	2.2%	10127	9,871	256	2.5%
1995	18141	17,877	264	1.5%	14422	14,236	186	1.3%	8072	7,939	133	1.6%	11690	11,445	245	2.1%
1996	18321	18,149	172	0.9%	13444	13,340	104	0.8%	14142	14,027	115	0.8%	14495	14,394	101	0.7%
1997	21378	21,251	127	0.6%	15988	15,897	91	0.6%	16825	16,694	131	0.8%	17041	16,945	96	0.6%
1998	22022	21,969	53	0.2%	16567	16,519	48	0.3%	16193	16,148	45	0.3%	16835	16,795	40	0.2%
1999	23789	23,747	42	0.2%	17925	17,896	29	0.2%	18902	18,859	43	0.2%	19983	19,940	43	0.2%
2000	3470	3,464	6	0.2%	9980	9,960	20	0.2%	19261	19,224	37	0.2%	20230	20,194	36	0.2%
2001	120	116	4	3.3%	320	318	2	0.6%	1289	1,286	3	0.2%	2483	2,479	4	0.2%
2002									21	21	0	0.0%	73	72	1	0.0%
2,002	***229,372***	***216,703***	***12,669***	***5.5%***	***183,907***	***174,298***	***9,609***	***5.2%***	***150,684***	***144,135***	***6,549***	***4.3%***	***180,956***	***171,038***	***9,918***	***5.5%***

Appendix B Parsons Data Request Specifications

Appendix B
Parsons Data Request Specifications

August 2, 2002

A request for data meeting the following specifications was submitted to the Clark County Department of Air Quality Management to meet the requirements of the contract for Consulting Services for Decentralized Vehicle Inspection and Maintenance Program Analysis – CBE Number 1746-02

The data will be taken from the DMV's Vehicle Identification Database (VID) for July 1, 2001through June 30, 2002. Parsons will need the data to be provided on a compact disk readable in Microsoft Access 2002.

Only vehicle test records meeting the following criteria were used in the analysis:

- 1968 and newer light-duty vehicles for which a tailpipe inspection is performed and failed, and post-repair tailpipe inspection results are available and were performed at the same type of station (i.e., either a test-only or test-and-repair station);
- Gasoline powered; and
- Vehicles registered within Clark County.

Vehicle data test records provided to Parsons need to contain the following fields:

- Facility identification information
- Vehicle license plate and VIN
- Vehicle type, GVWR, model year, make and model
- Test type (i.e., initial, after-repair or waiver)
- Test date and time
- Emission standards category and cut points
- Pre-repair idle test results for HC and CO
- Pre-repair 2500 RPM test results for HC and CO
- Repair information
- Post-repair idle test results for HC and CO
- Post-repair 2500 RPM test results for HC and CO
- Pass/Fail result

Vehicle tests resulting in the issuance of a waiver and undercover vehicle tests will need to be removed from the data set. It is assumed that vehicle test records will have been through a quality assurance check to ensure that only valid entries are included in each of the fields.

The test records will need to be matched according to the VIN on each vehicle to identify the first initial test and final after-repairs test. Each matched test record were given a consecutively assigned number with the information above listed in columns across the page.

It is unlikely that the inspection information provided will include all vehicles in the entire fleet of vehicles subject to inspection in Clark County because of bad records, inability to match before- and after-repair tests or other reasons. Therefore, Parsons will need information from the State delineating the model-year distribution of the overall fleet in Clark County and the numbers for each model-year category that are subject to the program in Clark County.

Appendix C Description of Detailed Analysis

Detailed Analysis Steps

The following is a listing of the steps that were taken to perform the analysis of the data once the data is provided to Parsons:

1. Data were extracted from the zip file into an ASCII file in Microsoft Notepad.
2. Extracted data were imported into Microsoft Excel if less than 65,536 records (maximum number of rows in a single Excel spreadsheet) and into Microsoft Access if greater.
3. Data were checked to ensure that it meets all the requirements contained in the data specifications. For example, if there is no matching record for a particular test, the initial test was deleted from the data set.
4. The following identifies the number of characters for each record and whether it is numeric, alpha or a combination of the two:
5. There are numerous records where the VIN is the same for initial and retest inspections, but the license plate entries are different. In those cases the comparison was done by the VIN.
6. Additional rows were created to add column headings.
7. Additional columns were created to store a sequential ID number and calculated reductions in 2500 RPM and idle emission readings between the initial and retests.
8. Data were sorted by Station Type.
9. Data with no license plate number or is shown as “Non-NV” were left in the data set in order to increase the sample size.
10. Data will then be sorted by VIN, date and time to establish a match and the sequence of testing.

Record	Length of Record	Alpha, Numeric or Combination	Acceptable Range
Station ID	8	Alpha-numeric	**N/A**
Station Type	3	Alpha-numeric	**A1G or A2G**
License	6	Alpha-numeric	**N/A**
VIN	17	Alpha-numeric	**N/A**
Vehicle Type	1	Alpha	**P, M or T**
GVWR	4	Numeric	**Max = 8500**
Model Year	4	Numeric	**N/A**
Make	4	Alpha	**N/A**
Test Type	1	Alpha	**I or R**
Test Date	9	Numeric	**7/1/01 to 6/30/02**
Test Time (Military)	5	Numeric	**0 – 2400**
CO Emission Std	4	Numeric	**N/A**
HC Emission Std	4	Numeric	**N/A**
Idle CO Reading	4	Numeric	
Idle HC Reading	4	Numeric	
2500 CO Reading	4	Numeric	
2500 HC Reading	4	Numeric	
Test Result	**1**	**Alpha**	**P or F**

Data manipulation required for each contract deliverable was performed as indicated below:

<u>Overall proportion of emissions reduced by station type</u>

11. Additional columns were created to store calculated reductions in 2500 RPM and idle emission readings between the initial and retests.
12. Data were sorted by VIN, date and time.
13. Reductions were calculated by subtracting the initial test results from the last test result.
14. Overall average emissions benefits were calculated for the data set using macro contained in Excel which sums the change from the initial and last retest and divides by the number of vehicles.
15. The proportion, in terms of percent reduction of emissions, was calculated by dividing the average amount of emissions reduced by each station type, by the total reduction and converting to a percentage.

Proportion of each type of station that falls into the upper, middle and low categories of effectiveness

16. Categories of effectiveness were defined based on the average level of emissions reduced for each type of station
17. The emission results were sorted by station number for all stations performing more than 100 inspections per year.
18. The proportion of emissions reduced for each station was calculated as shown in items #12 - #15 above.

Average reductions achieved for each type of station

19. The proportion of emissions reduced for each station was calculated as shown in items #12 - #15 above.

Average reductions achieved for different year model vehicles

20. Data for each type of station were sorted by vehicle model year.
21. The reductions were calculated by subtracting the initial test results from the last test result.
22. The average emissions benefits were calculated for CO for each model year using a formula entered into the Excel spreadsheet cells, which sums the change from the initial and last retest and then sum of the reductions were divided by the number of records.

Note: The sample size was small for some model years, so several model years were grouped together to make a category of appropriate size. Groupings were approved by the DAQM.

Additional tasks:

1. Calculate the average of the CO emissions results for the passing test for all matched vehicles for each type of station.

Appendix D Performance Categories of Stations

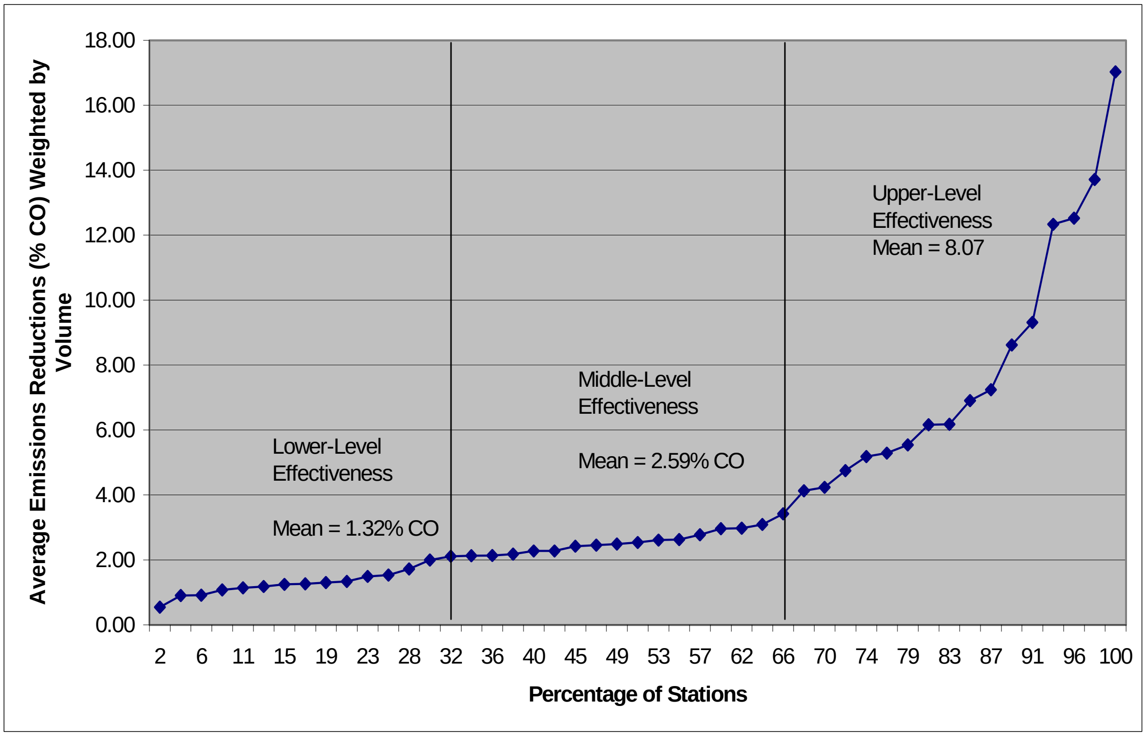
Proportion of Each Type of Station Falling into the Upper, Middle and Low Categories of Performance

For the purposes of identifying performance levels for each type of station, stations were divided into upper, middle or lower categories of performance. This provides information about the number of test-only and test-and-repair stations providing the greatest emission benefits for the program. This analysis helps program compliance staff to identify where resources may be allocated most cost effectively. Historically, the USEPA has been very concerned about compliance with program regulations. If illegal testing practices are rampant, those practices may negate emission benefits accrued. Stations not attaining at least a middle level category of performance warrant a careful review of their inspection practices.

This analysis sorts the test records by station type where there was an initial and a retest inspection performed on vehicles at the same type of station. The data were then sorted by Station ID number. Stations performing fewer than 100 inspections per year were considered insignificant and excluded from this portion of the analysis. Emission benefits generated by the remaining stations were analyzed for the first and last test for each matching VIN. The average emissions reduced were calculated for each vehicle, summed and tabulated into a summary table. The stations were ranked by the average emissions reduced in the summary table and a cumulative percentage of stations were calculated. Since some stations perform many more inspections than others do, the emissions reduced were weighted by the volume (i.e., the "average emissions reduced" were multiplied by a factor that was generated based on the percentage of tests performed by each station).

Once the benefits were calculated, cut points were identified to categorize the stations into Upper, Middle and Lower Level performance groups. The cut points chosen to separate the stations into categories of performance were selected by the magnitude of change in the slope of the curve joining a group of points. Figure 5 below shows the distribution of average emission reductions weighted by the volume of tests performed, at the test-and-repair stations. The vertical lines indicate the cut points selected for the Low, Middle and Upper Level categories of performance. The Lower Level category includes 32 percent of the test-and-repair stations. This occurs where the curve of the line crosses over below the two percent horizontal grid line. Stations in the Upper Level category of performance constitute approximately 34 percent of the test-and-repair stations. The curve climbs steadily, increasing in slope, from this point to the right side of the graph.

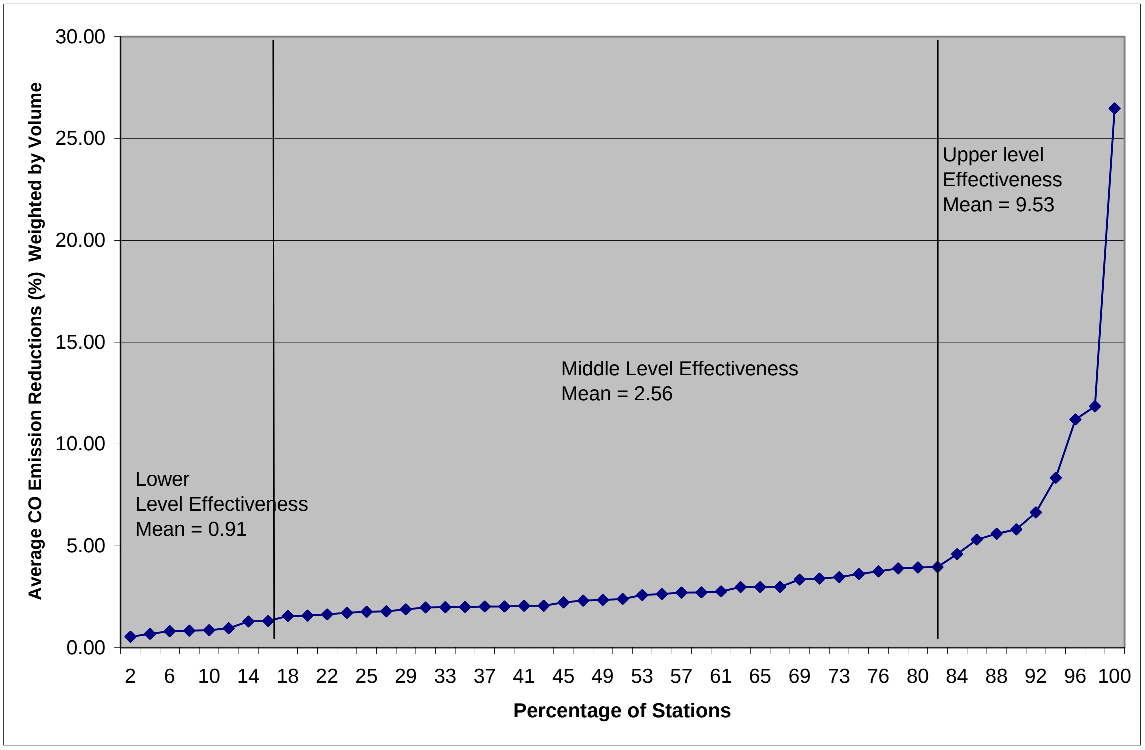
Figure 5 Test-and-Repair Station Average Emissions Reduced by Percentage of Stations



A dramatic difference exists between the test-and-repair stations in the upper level of performance and test-and-repair stations ranked in the lower and middle levels. Based on this information, the DMV may choose to evaluate the inspection practices at the stations ranked in the middle and lower level categories. Test-and-repair stations have an inherent conflict of interest because it is important to maintain the loyalty of customers. Test-and-repair stations may avoid failing vehicles more often than test-only stations to maintain their customer base. Because of the dramatic change in the slope of the curve, further investigation may be warranted.

Figure 6 presents data for the test-only stations and it shows a similar pattern for emissions reduced but with significantly different inflection points (i.e., where the slope of the curve changes). The curve drops off gradually on the left side of the first vertical marker indicating that approximately 16 percent of the stations rank in the Lower Level performance category and about 18 percent of the stations rank in the Upper Level performance category.

Figure 6 Test-Only Station Average Emissions Reduced by Percent of Stations



Test-only stations do not have the same inherent conflict of interest as the test-and-repair stations, however, the DMV may want to investigate the difference between the upper level stations and the lower and middle level stations in the interest of optimizing the performance of the I/M program.

ATTACHMENT I:

Wildfire Atypical Events Analyses

Wildfire Atypical Event Analysis for Ozone Attainment Demonstration State Implementation Plan (SIP)

Final Report Prepared for

U.S. EPA Region 9
San Francisco, CA

November 2023

STi Sonoma Technology

This document contains blank pages to accommodate two-sided printing.

Wildfire Atypical Event Analysis for Ozone Attainment Demonstration State Implementation Plan (SIP)

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Final Report
STI-1922072-8019

November 2023

Cover graphic shows visibility images taken from the M Resort Hotel in Clark County, Nevada, during the exceptional event on August 7, 2021. Visibility images are available in real-time from Clark County DES here: https://bit.ly/408P7yD.

Contents

Figures

Tables

1. 2016 Ozone Technical Supporting Documents

This document includes technical analyses conducted by the Clark County Department of Environmental Sustainability (DES), Division of Air Quality, assessing the likelihood that emissions from several large California wildfires impacted air quality within the Las Vegas Valley (LVV) on specific days during the summer of 2016. This report supports the selection of fire-influenced "exceptional event-like days" during 2016 that are referenced in the Weight of Evidence portion of the Clark County Moderate Ozone Nonattainment Area State Implementation Plan (SIP).

1.1 Clark County and Nonattainment Area Description

Clark County covers 20,956 km^2 at the southern tip of Nevada and has a population of over 2.2 million. More than 95% of the county's residents live in the LVV, which is part of the Mojave Desert and constitutes Hydrographic Area (HA) 212. The valley encompasses about 1,600 km^2 and is surrounded by mountains extending 2,000 to 10,000 feet above its floor (**Figure 1**). The valley slopes downward from west to east (approximately 900 to 500 m above mean sea level). The terrain within and surrounding the LVV affects the local climatology by driving variations in wind, temperature, and precipitation.

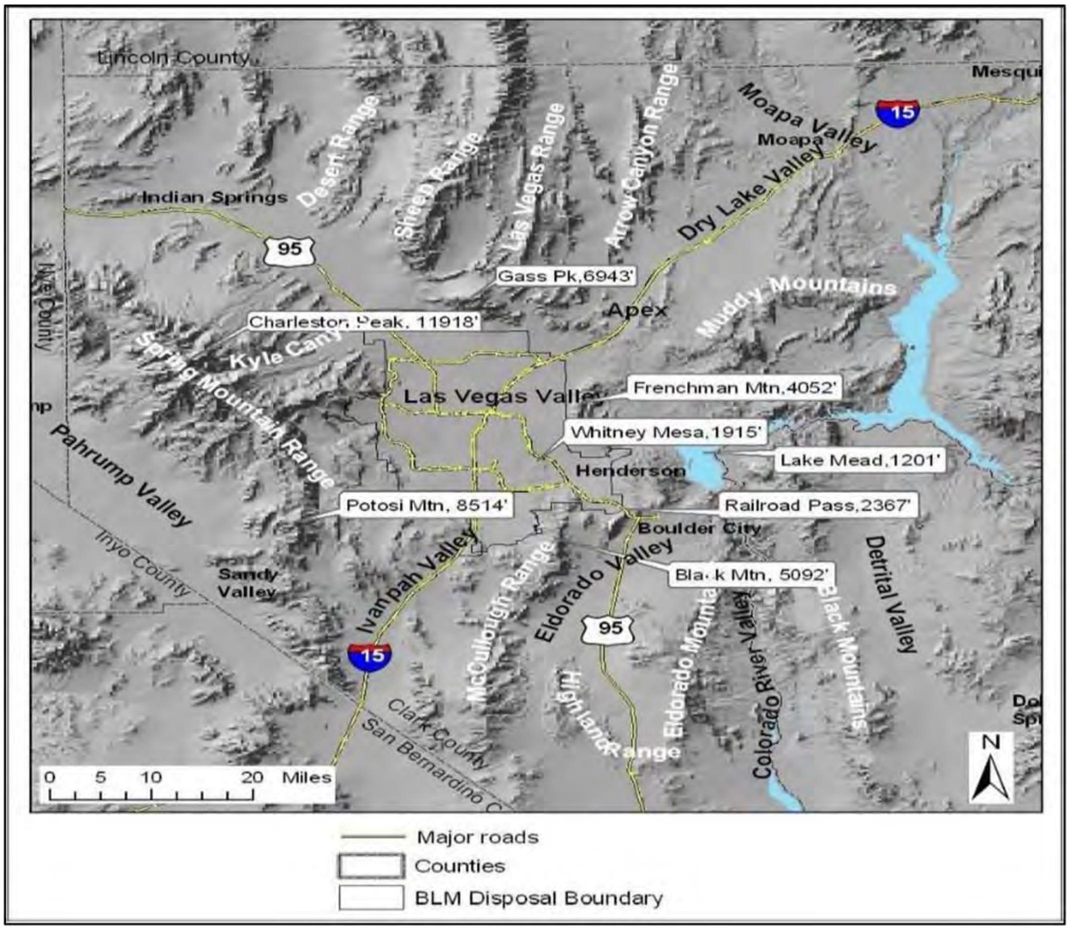

Figure 1. Mountain ranges and hydrographic areas surrounding the Las Vegas Valley.

Valley weather is characterized by low rainfall, hot summers, and mild winters. On average, June is the driest month, whereas monsoons from the Gulf of California increase humidity and cloud cover during July and August. The Interstate 15 (I-15) corridor from Cajon Pass in California through the Mojave Desert links Las Vegas with the eastern Los Angeles Basin, about 275 km to the southwest. This corridor is a potential pathway for the export of pollution from Los Angeles to the Mojave Desert and the LVV.

Figure 2 shows the locations of Clark County ozone monitors. Most of the stations, including Paul Meyer (PM), Walter Johnson (WJ), Palo Verde (PV), Joe Neal (JO), Jerome Mack (JM), and Green Valley (GV), are within the populated areas of the LVV, but there are other outlying stations at Apex (AP), Mesquite (MQ), Boulder City (BC), Jean (JN), and Indian Springs (IS). An additional station at the Spring Mountain Youth Camp (SM, approximately 2.58 km above sea level) was operated as a special purpose monitoring site.

Figure 2. Map of Clark County showing the 2018 ozone monitoring network, hydrographic areas, and major roadways.

Figure 3 and Figure 4 show the locations of Clark County's Federal Equivalent Method (FEM) and Federal Reference Method (FRM) $PM_{2.5}$ monitors, respectively. Most of the stations are within the populated areas of the LVV, with one outlying station in Jean, Nevada. Jean is considered a regional background site because (1) it is located far enough from the valley to avoid impacts from local emissions, and (2) it is upwind of the LVV during the summer season and senses pollution entering the LVV from southern California.

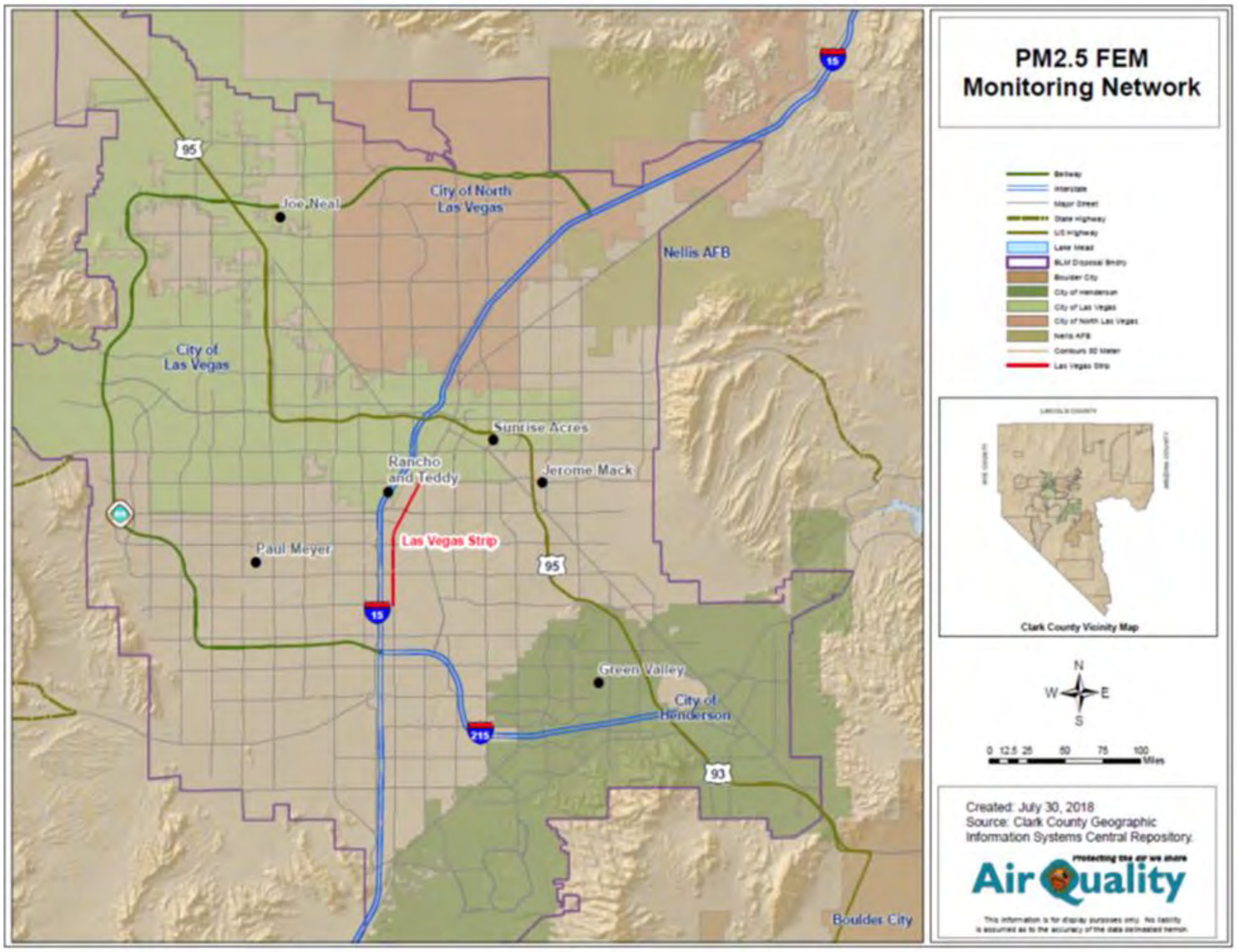

Figure 3. Locations of FEM $PM_{2.5}$ monitors within the LVV in 2018. The Jean FEM monitor (not shown) is located well south of the valley along I-15 (see Figure 2).

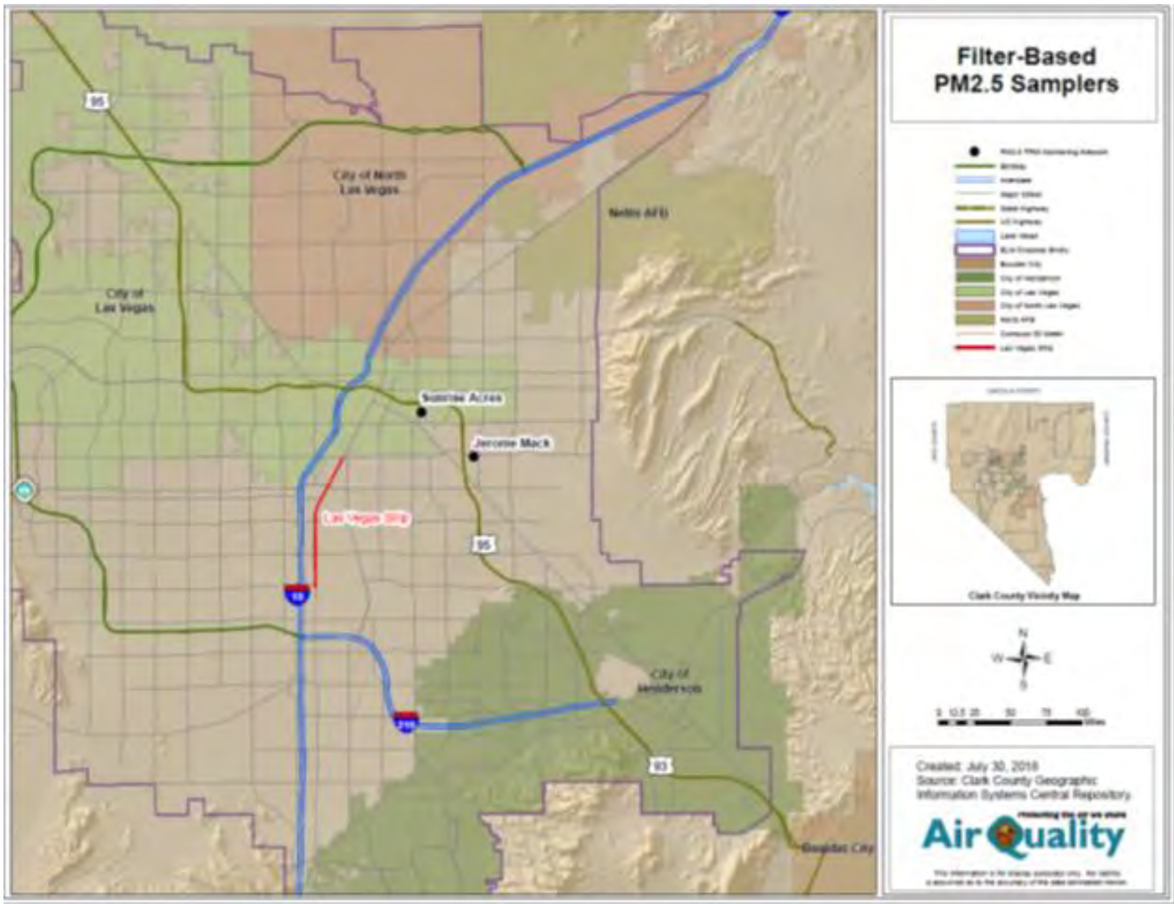

Figure 4. Locations of FRM $PM_{2.5}$ monitors within the LVV in 2018.

1.2 Prevailing Meteorological Conditions

During the summer season, the weather across the Mojave Desert is dictated by a semi-permanent surface thermal low-pressure system. Thermal lows are caused by intense surface heating and strong capping subsidence aloft associated with broad upper-level high pressure ridging. Therefore, thermal lows are relatively shallow, extending from 850 hPa (approximately 1,500 m) to 700 hPa (approximately 3,000 m) within the lower troposphere. Based on a study of synoptic climatology of thermal lows over southwestern North America (Rowson et al., 1992[1]), this system is most prevalent from mid-June through mid-September and reaches its maximum vertical extent near 700 hPa in July and early August. The low normally extends across the Mojave, Yuma, and Sonora Deserts and the plateau highlands of the Sierra Madre Occidental. Resulting surface winds in southern Nevada are most frequently northwesterly from central/northern California and southerly from Mexico and southern California. As a result, there is a strong link between the ozone concentration in the LVV

[1] Rowson, D. and Colucci S., 1992. Synoptic Climatology of Thermal Low-Pressure Systems over South-Western North America. *International Journal of Climatology*, vol. 12: 529-545.

and the smoke from wildfires in California and Mexico. Moreover, the meteorological conditions associated with thermal lows enhance vertical mixing of smoke-generated ozone plumes within the lowest 3,000 m and downward subsidence of plumes above that altitude. All of these factors help to elevate episodic ozone concentration in the LVV.

1.3 2016 California Wildfire Events

1.3.1 Summary of 2016 Wildfire Frequency

Western U.S. wildfire frequencies and intensities are increasing every year. They are bigger, hotter, and more deadly and destructive. In 2016, a total of 6,954 fires had burned 669,534 acres in California, according to the California Department of Forestry and Fire Protection (CAL FIRE). The number of fires and burned area increased greatly in June, July, and August, as shown in Figure 5 from the 2016 Wildfire Activity Statistics report published by CAL FIRE. Table 1 lists all fires that exceeded 1,000 acres from May through September of 2016. Starting in June, significant wildfires broke out, such as Erskine fire. Later, a series of large wildfires erupted across California, mostly in the southern part of the state, including the destructive Sand and Soberanes fires in July and the Chimney, Blue Cut, Cedar, Rey, and Gap fires in August. As shown in Figure 6, more frequent LVV ozone exceedances after mid-June coincided with these California wildfire events. Table 2 shows the maximum daily 8-hr average (MDA8) ozone recorded at LVV monitoring site on days impacted by 2016 wildfires. Details for each event are presented below.

Table 1. List of fires exceeding 1,000 acres during the 2016 California wildfire season.

Name	County	Acres	Start Date	Containment Date	Notes
Roberts	San Luis Obispo	3,712	18-May-16	20-May-16	
Metz	Monterey	3,876	22-May-16	25-May-16	
Coleman	Monterey	2.520	4-Jun-16	17-Jun-16	
Pony	Siskiyou	2,860	7-Jun-16	30-Jun-16	
Sherpa	Santa Barbara	7,474	15-Jun-16	12-Jul-16	
Border	San Diego	7,609	19-Jun-16	30-Jun-16	2 fatalities, 5 hoes and 11 outbuildings destroyed
Pine	Ventura	2,304	19-Jun-16	17-Jul-16	
San Gabriel Complex	Los Angeles	5,399	20-Jun-16	23-Jul-16	Reservoir Fire burned 1,146 acres; Fish Fire burned 4,253 acres
Erskine	Kern	48,019	23-Jun-16	12-Jul-16	2 fatalities, 285 homes destroyed, 12 damaged
Trailhead	Placer	5,646	28-Jun-16	18-Jul-16	
Deer	Kern	1,785	1-Jul-16	11-Jul-16	
Curry	Fresno	2,944	1-Jul-16	5-Jul-16	

Name	County	Acres	Start Date	Containment Date	Notes
Sage	Los Angeles	1,109	9-Jul-16	16-Jul-16	
Roblar	San Diego	1,245	21-Jul-16	30-Jul-16	
Sand	Los Angeles	41,432	22-Jul-16	3-Aug-16	2 fatalities, 18 homes destroyed, 4 damaged
Soberanes	Monterey	132,100	22-Jul-16	12-Oct-16	1 fatality, 3 injuries, 57 homes and 11 outbuildings destroyed
Goose	Fresno	2,241	30-Jul-16	9-Aug-16	4 homes, 5 outbuildings destroyed
Cold	Yolo	5,731	2-Aug-16	12-Aug-16	2 outbuildings destroyed
Pinot	San Bernardino	8,110	7-Aug-16	16-Aug-16	
Mineral	Fresno	7,050	9-Aug-16	18-Aug-16	2 structures destroyed
Chimney	San Luis Obispo	46,344	13-Aug-16	6-Sep-16	48 structures destroyed
Clayton	Lake	3,929	13-Aug-16	26-Aug-16	300 buildings destroyed
Blue Cut	San Bernardino	36,274	16-Aug-16	23-Aug-16	105 homes, 213 outbuildings destroyed
Cedar	Kern	29,322	16-Aug-16	30-Sep-16	
Rey	Santa Barbara	32,606	18-Aug-16	16-Sep-16	
Gap	Siskiyou	33,867	27-Aug-16	17-Sep-16	
Bogart	Riverside	1,470	30-Aug-16	2-Sep-16	1 outbuilding destroyed
Willard	Lassen	2,575	11-Sep-16	22-Sep-16	5 structures destroyed
Owens River	Mono	5,443	17-Sep-16	15-Oct-16	
Canyon	Santa Barbara	12,518	17-Sep-16	24-Sep-16	1 firefighter killed in crash
Sawmill	Sonoma	1,547	25-Sep-16	29-Sep-16	
Marshes	Tuolumne	1,080	26-Sep-16	4-Oct-16	
Loma	Santa Clara	4,474	26-Sep-16	12-Oct-16	28 structures destroyed

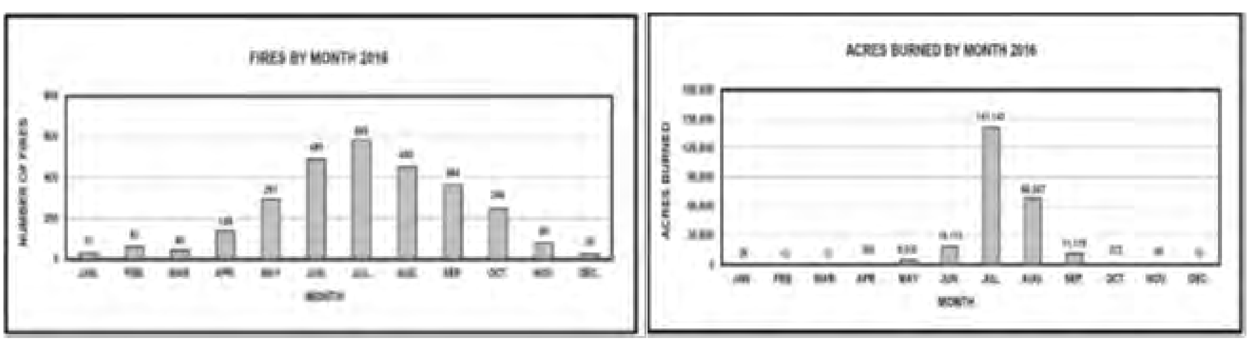

Figure 5. Number of fires and acres burned by month in 2016 (CAL FIRE, reference).

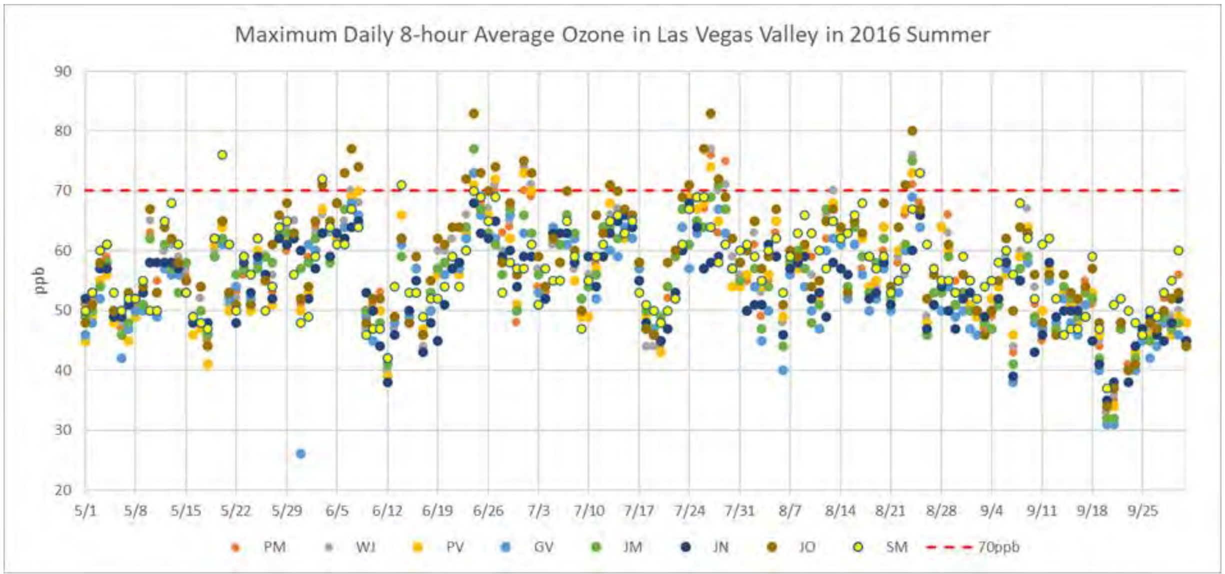

Figure 6. MDA8 ozone (ppb) at LVV monitors during the 2016 ozone season.

Table 2. MDA8 ozone (ppb) during days influenced by wildfires during the 2016 ozone season. "EE-like" days (red) are identified as impacted by wildfire smoke.

Date	PM	WJ	PV	GV	JM	JO	AP	JN	EE-like
6/24/2016	73	73	71	73	77	83	84	68	Y
6/25/2016	68	69	67	66	67	73	64	63	Y
6/26/2016	67	67	66	65	63	70	66	62	N
6/27/2016	70	71	72	62	61	74	57	65	Y
7/24/2016		69	69	57	61	71	48	68	Y
7/25/2016		65	67	63	65	69	65	64	N
7/26/2016	67	69	68	57	64	77	63	57	Y
7/27/2016	76	77	74	64	69	83	62	58	Y
7/28/2016	63	70	65	67	71	72	67	59	Y
7/29/2016	75	71	67	63	67	69	64	61	Y
8/23/2016	66	56	67	60	61	71	57	57	N
8/24/2016	71	76	73	69	75	80	68	60	Y

1.3.2 June 24-27, 2016

The Erskine Fire in Kern County, California was the second-largest wildfire of 2016 (Figure 7). It started on the afternoon of June 23, and by the evening of June 24, the fire had grown to over 30,000 acres with 5% containment. On July 11 the fire was 100% contained and the total burned area was ~47,864 acres.

Figure 7. Location and size of the Erskine Fire.

Figure 8 presents the upper-air synoptic weather patterns at 500 hPa (approximately 5,500 m) over June 22-27. A large trough of low pressure moved into the Pacific Northwest on June 22-23 and pushed across the intermountain western U.S. through June 25. An upper-level high pressure ridge was subsequently reestablished over the western U.S. As the high pressure strengthened over the region, winds lessened and conditions over southern Nevada became dry and very hot. Airflow over the region was mainly southwesterly on June 24 and shifted to northwesterly on June 25. During June 26-27, weak airflow shifted back from southwesterly to southeasterly. Consequently, elevated smoke from Erskine Fire was likely transported across the Mohave Desert and over the LVV, where a combination of strong subsidence and vertical mixing brought ozone and precursors to the surface.

At the surface, a weak stationary front passed through central Nevada (Figure 9) while a persistent thermal low system existed over southern Nevada. As a result, winds were light but ranged from westerly to southwesterly, bringing smoky air from the Erskine fire into the LVV. This weather pattern produced abundant sunshine, high temperatures, and low wind speeds, contributing to strong ozone generation with suppressed dilution. Therefore, this elevated ozone period was likely enhanced by the Erskine fire to exceed the ozone NAAQS, except perhaps during June 26 when ozone was likely diluted by a relatively deep mixing layer.

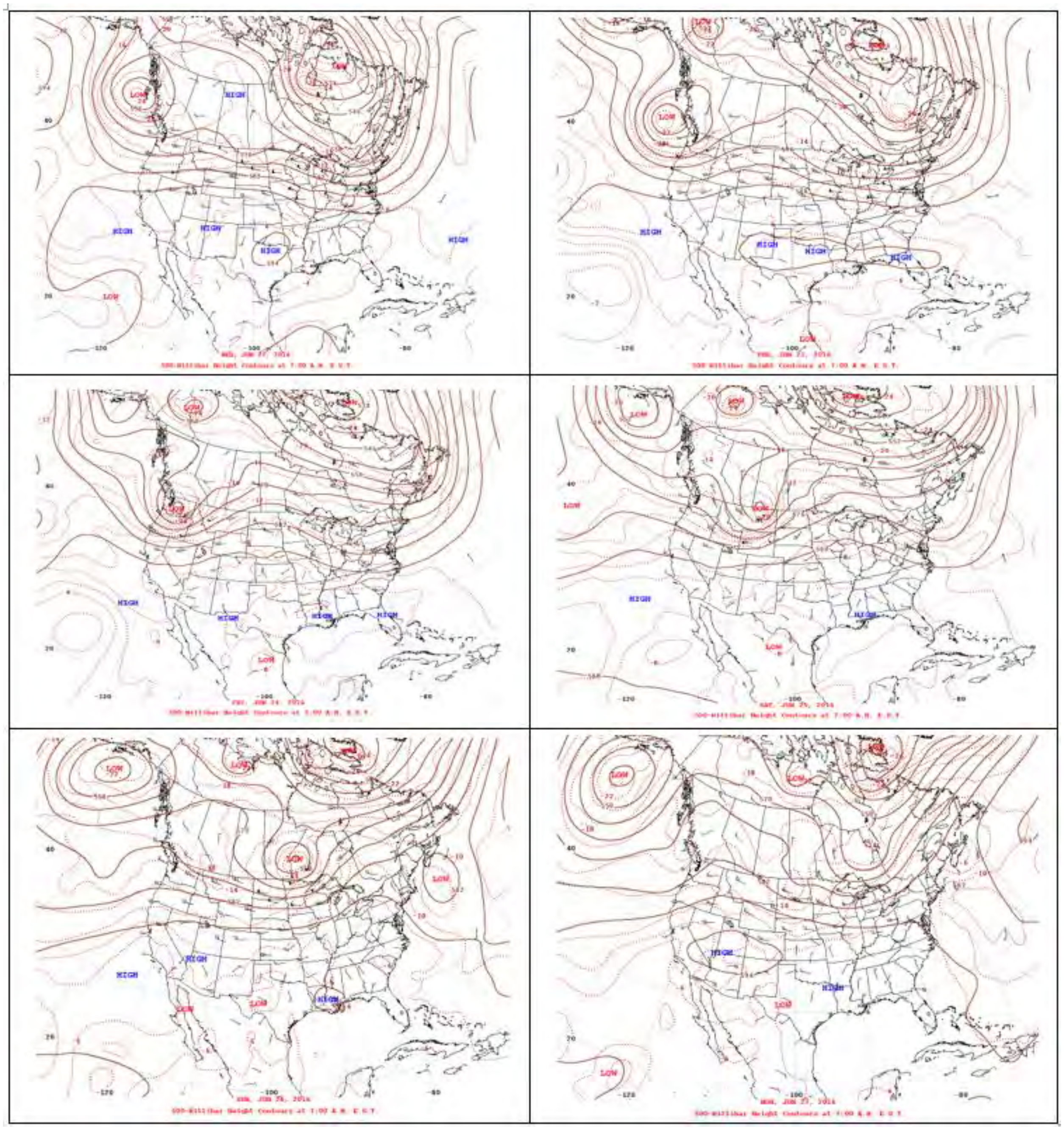

Figure 8. 500 hPa (approximately 5,500 m) weather patterns at 07:00 EST (04:00 PST) from June 22 to 27, 2016.

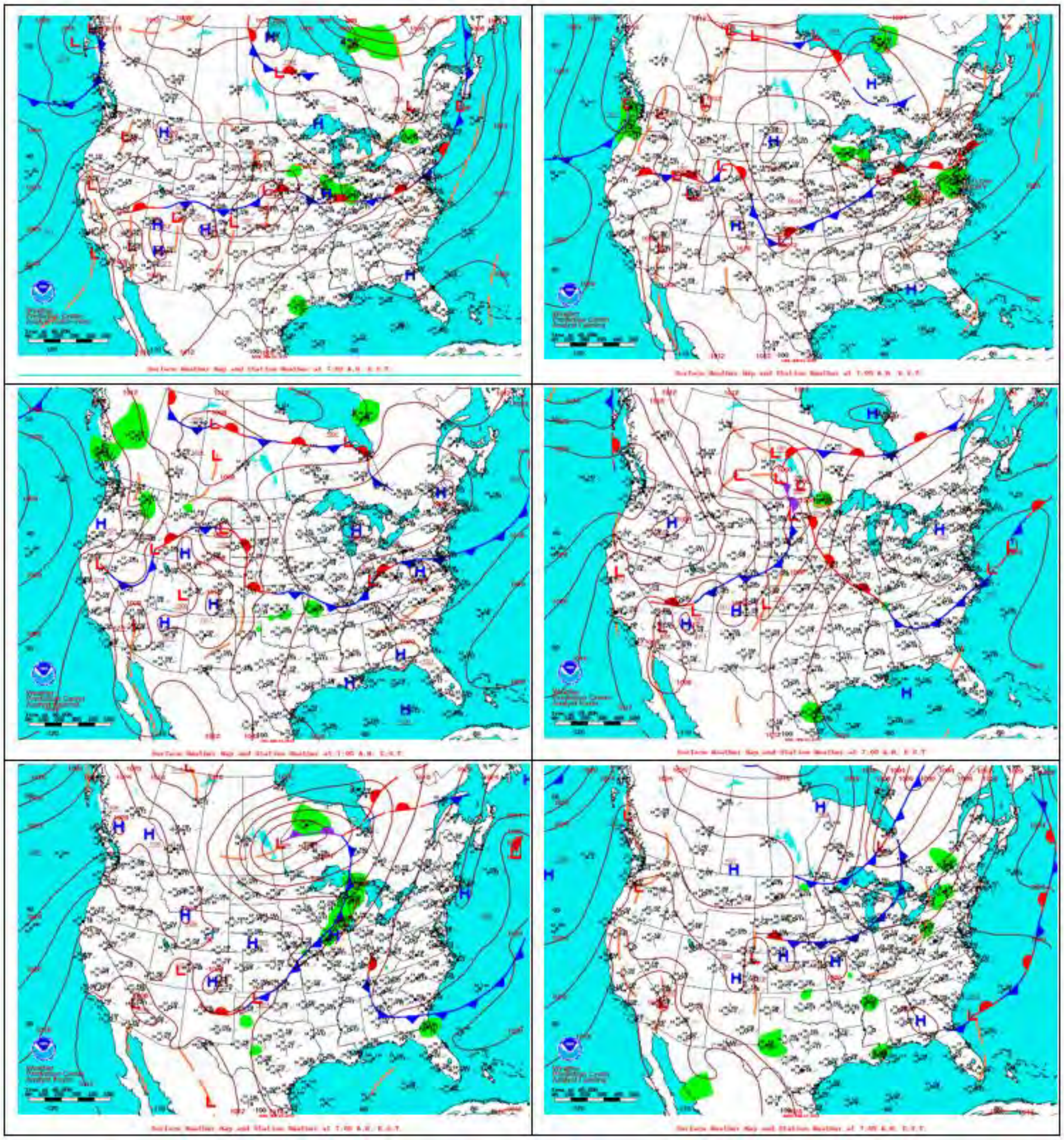

Figure 9. Surface weather patterns at 07:00 EST (04:00 PST) from June 22 to 27, 2016.

Figure 10 presents a visible satellite image showing smoke from the Erskine fire extending over Clark County on June 24. **Figure 11** shows 24-hr backward trajectories of airflow arriving in Las Vegas at 13:00 PST during June 24-27 at altitudes of 20, 200 and 2,000 m, along with NOAA Hazard Mapping System (HMS) smoke maps overlaid. Large areas of regional smoke, including from the Erskine fire, existed over or near the LVV on all days. The shorter backward trajectories starting on June 25 corroborate the low windspeeds associated with the dominant high-pressure conditions over the region, as described above. Figure 12 and Figure 13 show very high ozone and $PM_{2.5}$ concentrations associated with the smoke arriving in Las Vegas on June 24, resulting in most stations exceeding the NAAQS. Ozone at the elevated Spring Mountain site also provides evidence of an elevated layer of ozone arriving on this date and maintaining very high concentrations above 60 ppb throughout June 24-27. Figure 14 and Figure 15 show the hourly seasonal percentiles for ozone and $PM_{2.5}$ from 2014-2019 (May-August) compared to measured hourly ozone and $PM_{2.5}$ on June 24-27, 2016, at LVV sites and Jean (outlying site). Figure 14 shows the most excessive ozone on June 24, 2016, at the monitors in the valley and Jean. Figure 15 shows the most excessive $PM_{2.5}$ on June 24-25, 2016. All figures support the conclusion that wildfire smoke had been transported to the LVV.

Table 3 compares MDA8 ozone during June 24-27 against historical 95th percentile MDA8 ozone from 2014 to 2018 at monitoring sites with sufficient data. On June 24, MDA8 ozone exceeded the 95th percentile at all monitoring sites. Taken together, there is strong evidence that MDA8 ozone in the LVV was enhanced by emissions from the Erskine fire during this event.

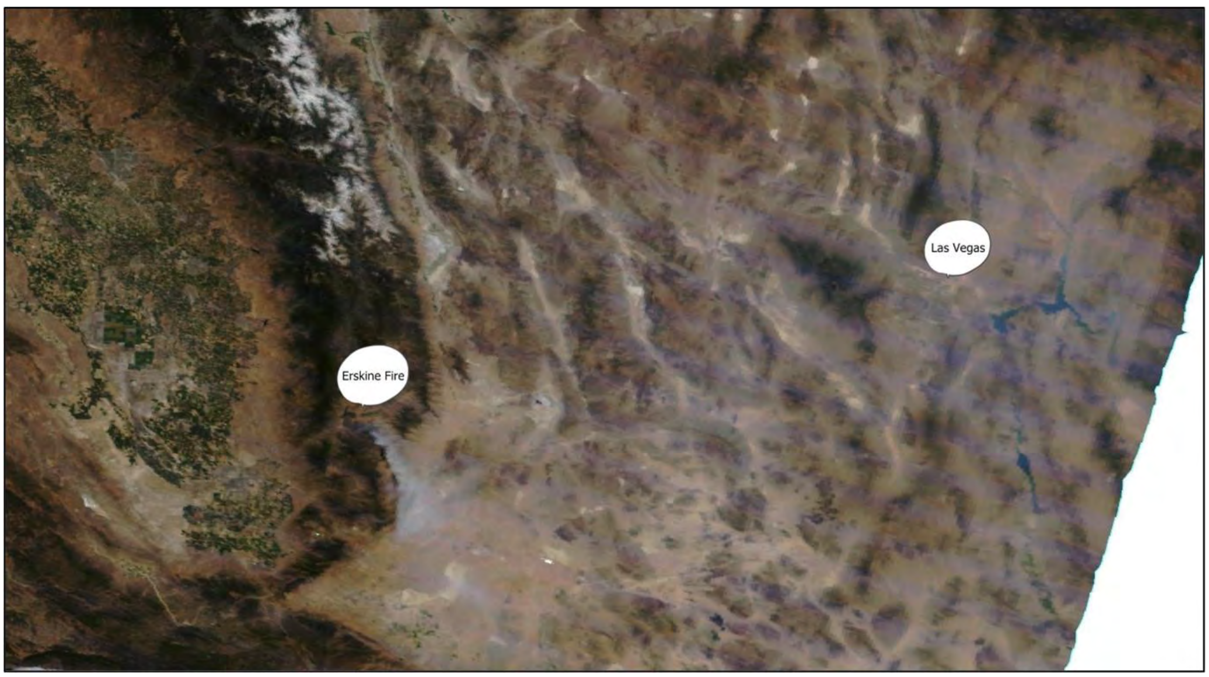

Figure 10. Visible satellite imagery of southern California and Nevada on June 24, 2016.

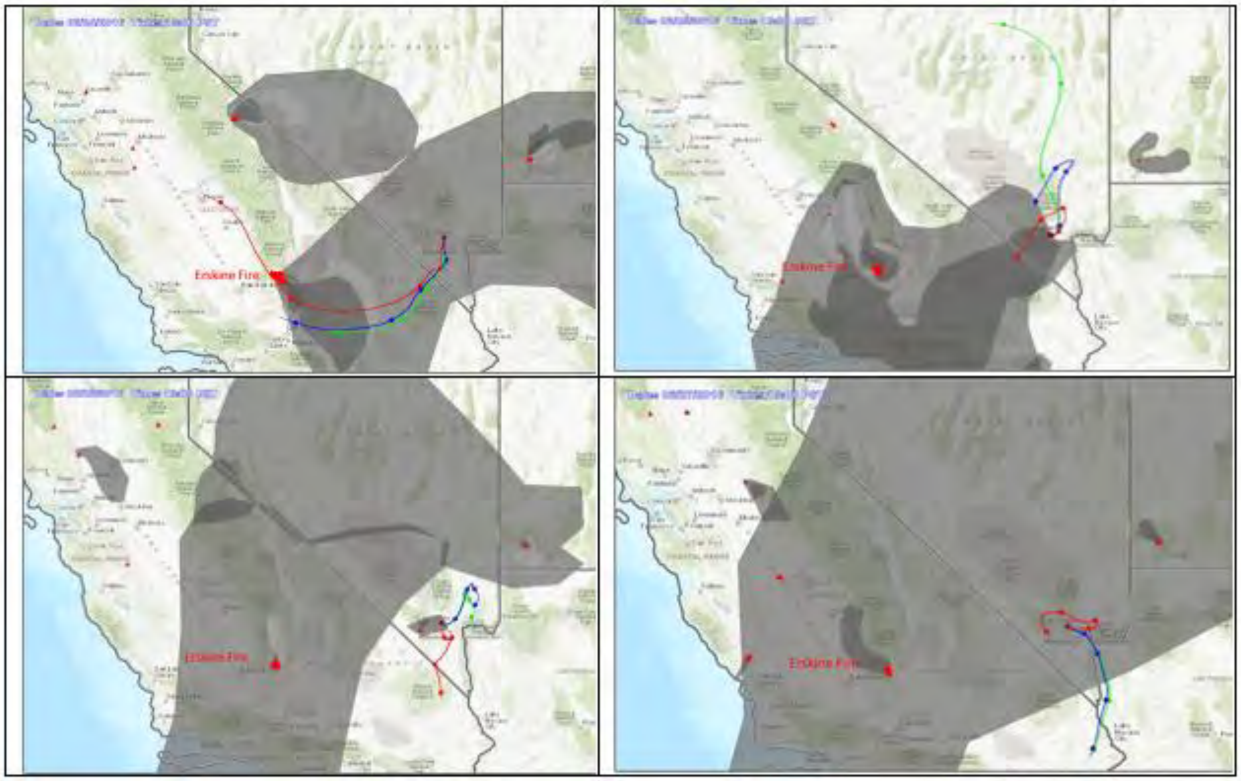

Figure 11. 24-hr backward trajectories arriving in Las Vegas at 13:00 PST on June 24-27, 2016, at altitudes of 20 m (green), 200 m (blue), and 2,000 m (red).

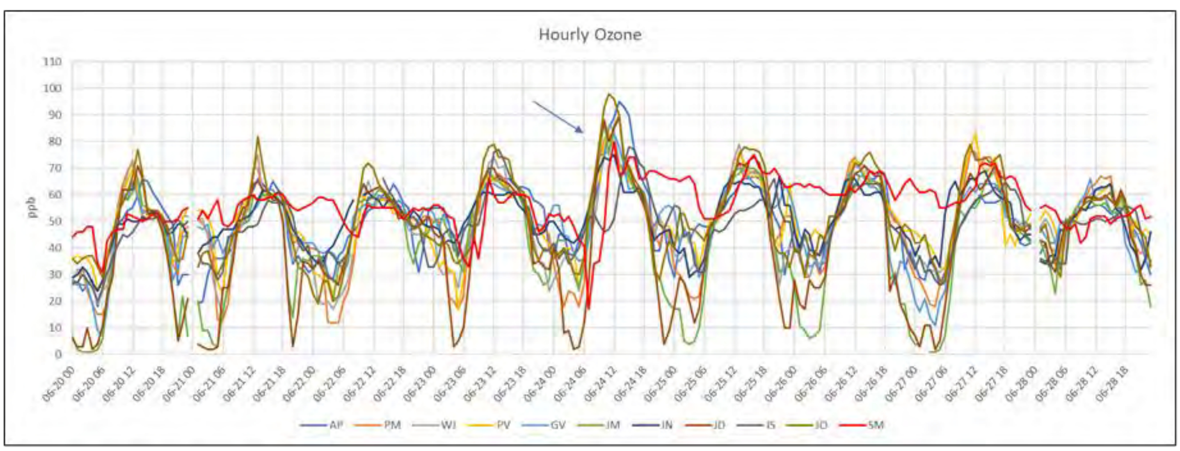

Figure 12. Time series of 1-hr ozone (ppb) at all LVV monitors during June 20-28, 2016.

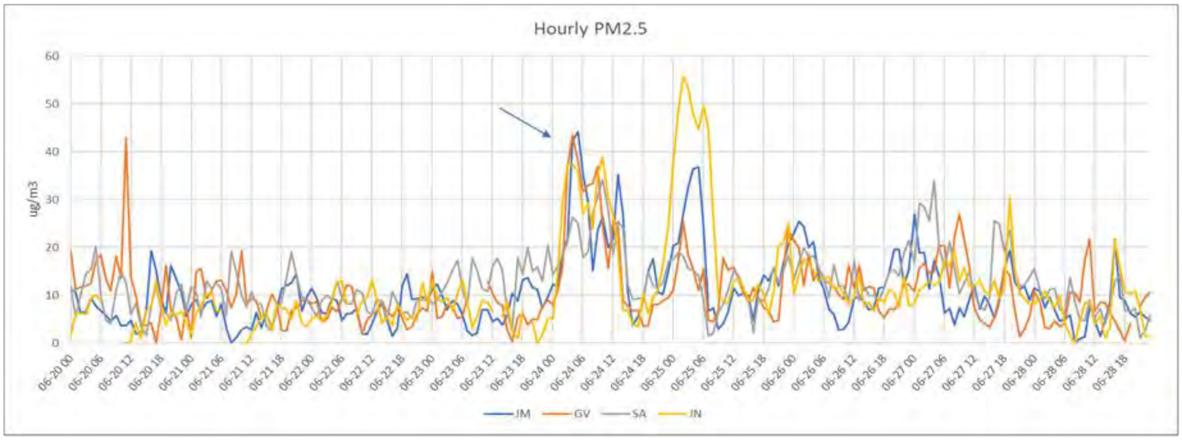

Figure 13. Time series of 1-hr $PM_{2.5}$ concentration (μg/m^3) at LVV FEM monitors during June 20-28, 2016.

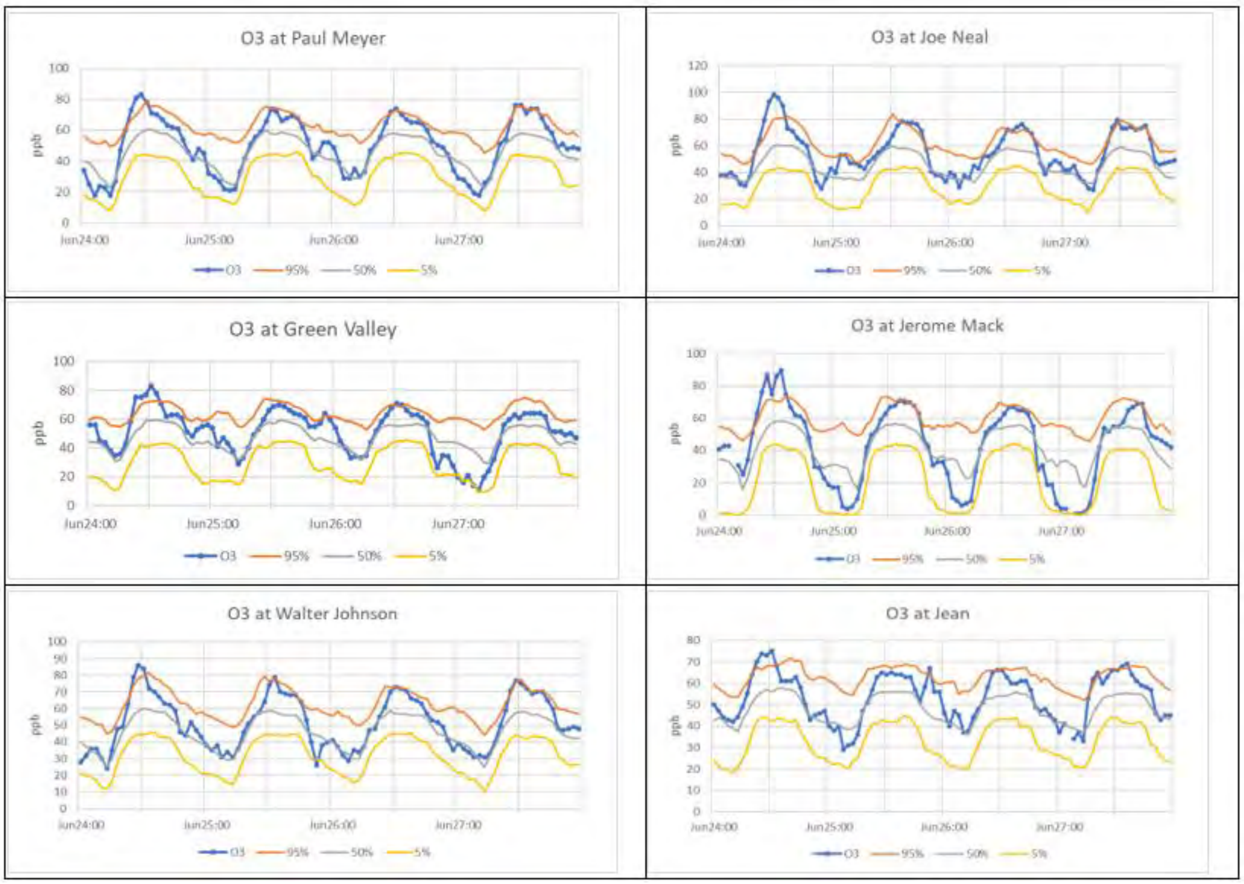

Figure 14. 6-yr hourly seasonal 95th, 50th, and 5th percentiles for ozone concentrations at the Paul Meyer, Joe Neal, Green Valley, Jerome Mack, Walter Johnson, and Jean monitoring sites during June 24-27, 2016.

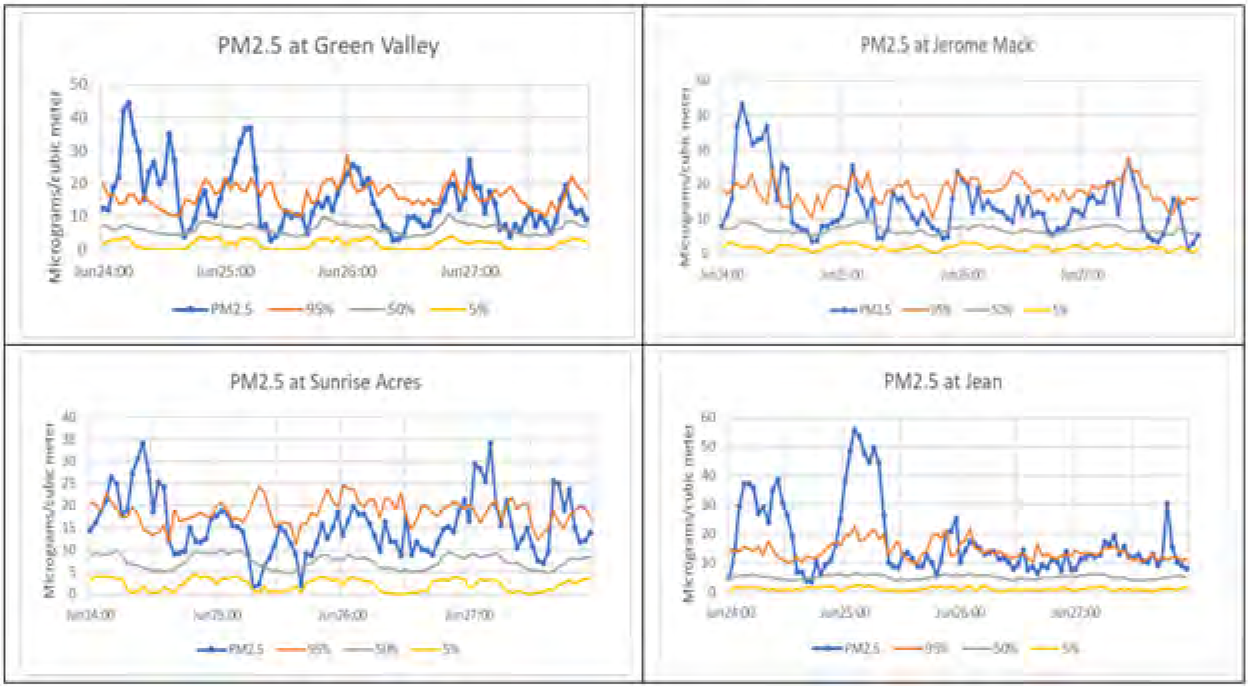

Figure 15. 6-yr hourly seasonal 95th, 50th, and 5th percentiles for $PM_{2.5}$ concentrations ($\mu g/m^3$) at LVV FEM monitors during June 24-27, 2016.

Table 3. Comparison of MDA8 ozone (ppb) during June 24-27 against 2014-2018 95th percentile MDA8 ozone concentrations.

2014-2018 (ppb)	PM	WJ	PV	GV	JM	JO	AP	JN
6/24	73	73	71	73	77	83	84	68
6/25	68	69	67	66	67	73	64	63
6/26	67	67	66	65	63	70	66	62
6/27	70	71	72	62	61	74	57	65
95th percentile	71	72	70	71	70	73	70	68

1.3.3 July 24-29, 2016

The Sand fire started during the afternoon of July 22 within the Angeles National Forest east of Santa Clarita, California (Figure 16). By the evening of July 23, the fire had grown to 20,000 acres with 10% containment, while on the morning of July 25 the fire was reported to reach 33,000 acres with 10% containment. On July 28, the fire reached an estimated 38,346 acres and was 65% contained.

The upper-air synoptic weather patterns at 500 hPa during July 24-29 (Figure 17) show that a weak short-wave trough initially propagated across the western U.S., then was replaced by an eastern Pacific ridge that broadened across the western U.S. The ridge was a persistent feature that dominated weather over the region for the remaining period. It was associated with light winds and deep subsidence from the upper troposphere that maintained clear skies and warm temperatures.

The surface analyses (Figure 18) show a weak trough associated with the upper-level trough propagated across Nevada on July 24, splitting the surface eastern Pacific high pressure. After the trough's passage on subsequent days, the thermal low system centered over Southern Nevada intensified with hot and dry conditions in the LVV throughout the period. On July 27, a transition to a widespread return of monsoonal moisture produced excessive heat resulting in extreme temperatures and low daytime wind speeds through July 29. During this event, airflow in the region varied from westerly to southerly and transported the smoke toward southern Nevada.

Figure 16. Location and size of the Sand fire.

Satellite imagery on July 23 (Figure 19) shows smoke from the Sand fire extending toward Clark County. Figure 20 shows 24-hr backward trajectories arriving at Las Vegas at 13:00 PST on July 24-29 at 100, 1,000 and 2,000 m with HMS smoke maps overlaid. Smoke remained over the LVV during July 24-26 while trajectories extended back toward the fire. On July 27 winds weakened substantially as shown by the shorter trajectory paths, leading to less ventilation that retained pollution within the LVV and promoted ozone production. Time series of ozone and $PM_{2.5}$ during July 22-30 (Figure 21 and Figure 22) show that smoke arrived in the LVV on July 23, after which ozone remained near or above 60 ppb at the high elevation Spring Mountain site (red). Figure 23 and Figure 24 show the hourly seasonal percentiles for ozone and $PM_{2.5}$ from 2014-2019 (May-August) compared to measured hourly ozone and $PM_{2.5}$ on July 24-27, 2016, at LVV sites and Jean. Figure 23 shows the diurnal ozone patterns are near or exceed 95th percentile on July 24-29, 2016, at the monitors in the valley and outlying site, Jean. Figure 24 shows the greatly elevated $PM_{2.5}$ on July 24-25, 2016. All figures support the conclusion that wildfire smoke had been transported to the LVV.

Table 4 compares MDA8 ozone against historical 95th percentile values from 2014 to 2018 at monitoring sites with sufficient data. During this event, the Sand fire burned during the entire period with an airflow pattern that consistently brought smoke toward the Las Vegas area. Strong and persistent high pressure dominated the region, resulting in continuous smoke and poor air quality in the Las Vegas Valley. On July 24, MDA8 ozone exceeded the 95th percentile at Jean (the upwind transport site). On July 26, MDA8 ozone exceeded the 95th percentile at Joe Neal; on July 27, MDA8 ozone exceeded the 95th percentile at Paul Meyer, Walter Johnson, Palo Verde and Joe Neal; on July 28, MDA8 ozone exceeded the 95th percentile at Jerome Mack; and on July 29, MDA8 ozone exceeded the 95th percentile at Paul Meyer. Although ozone reached extreme levels at just a single site on several days during this event, the western valley sites experienced relatively elevated high ozone too. Thus, these analyses provide evidence that ozone in the Las Vegas Valley was significantly impacted by the Sand Fire during this event.

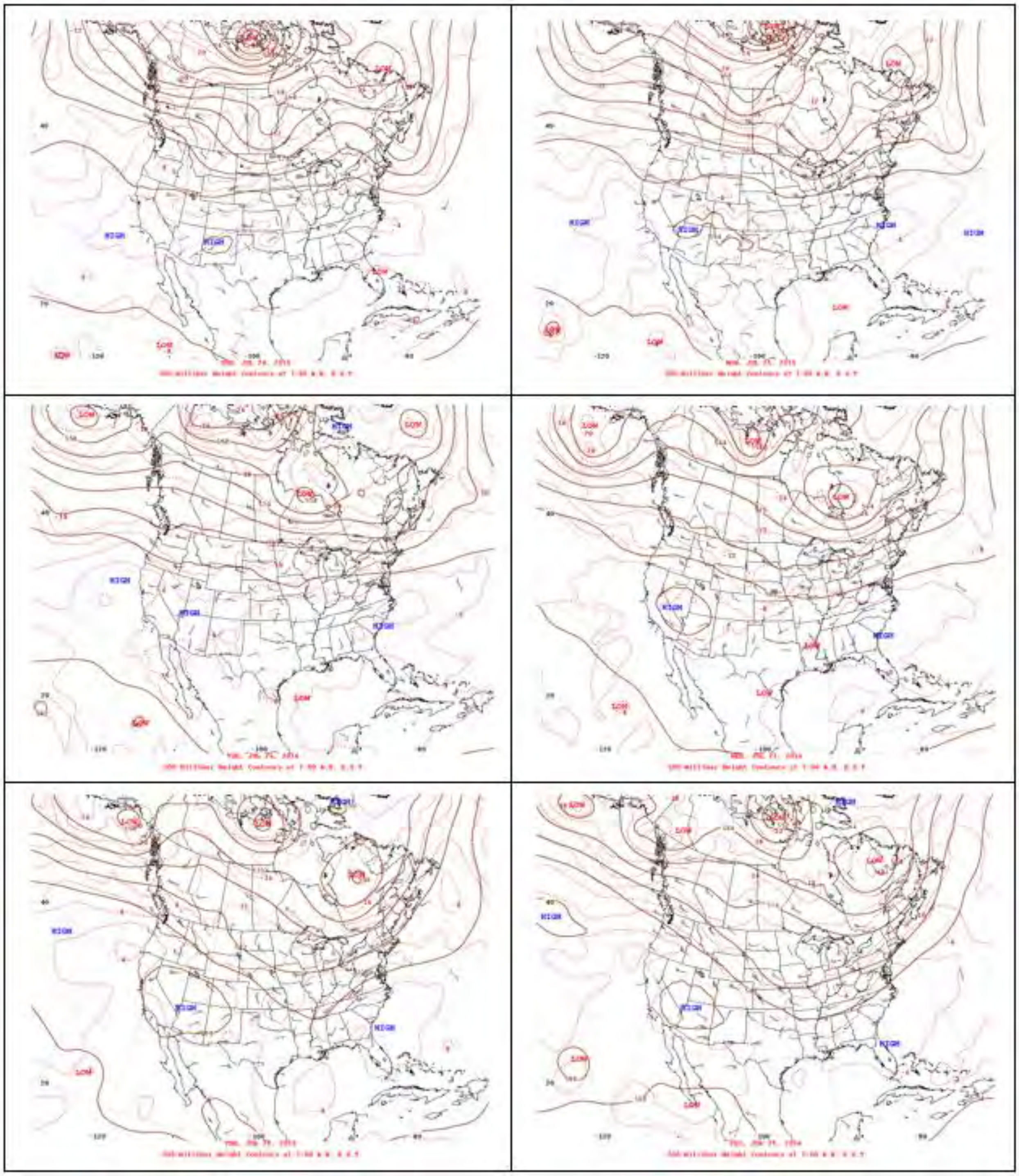

Figure 17. 500 hPa (approximately 5,500 m) weather patterns at 07:00 EST (04:00 PST) from July 24 to 29, 2016.

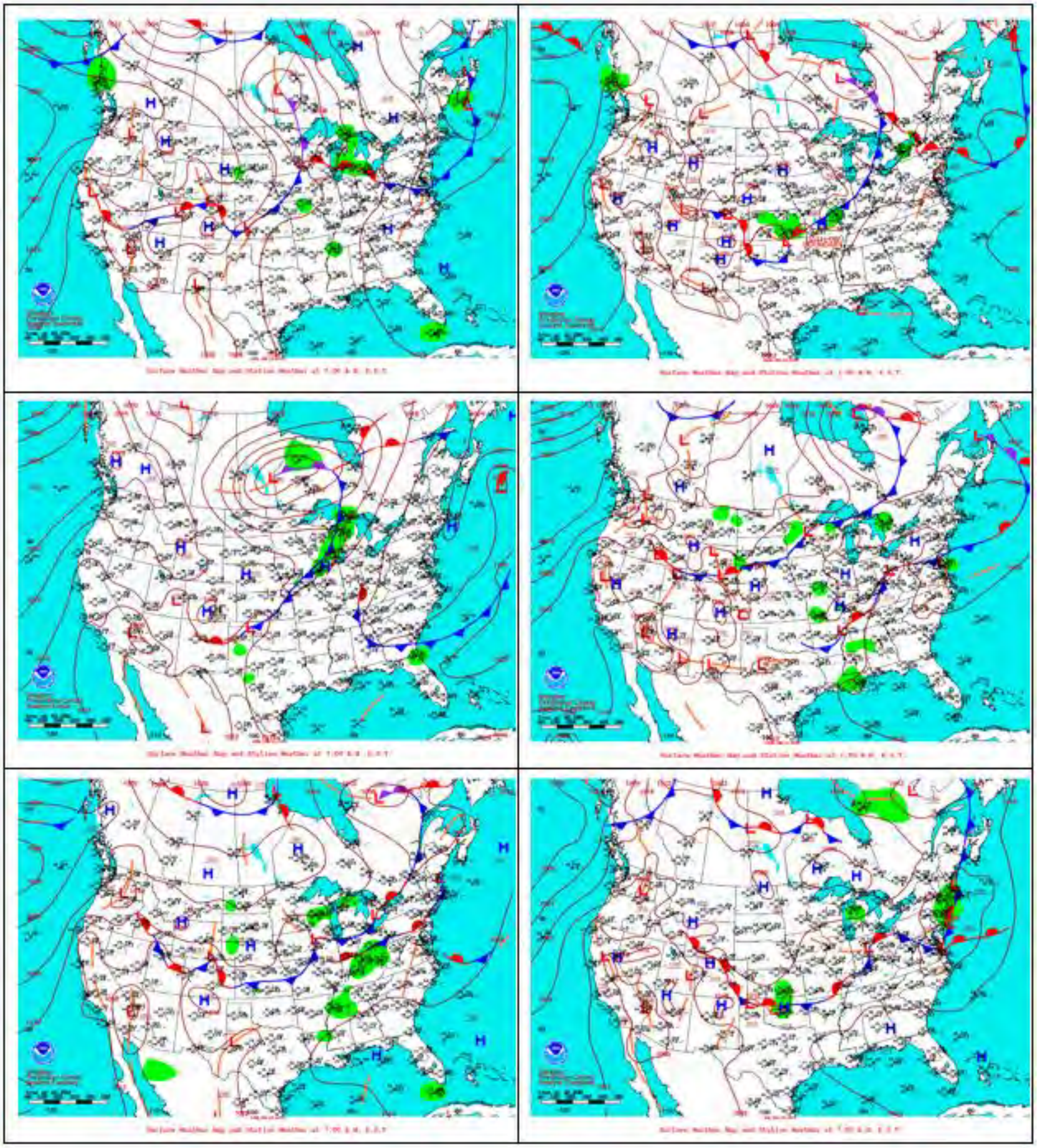

Figure 18. Surface weather patterns at 07:00 EST (04:00 PST) from July 24 to 29, 2016.

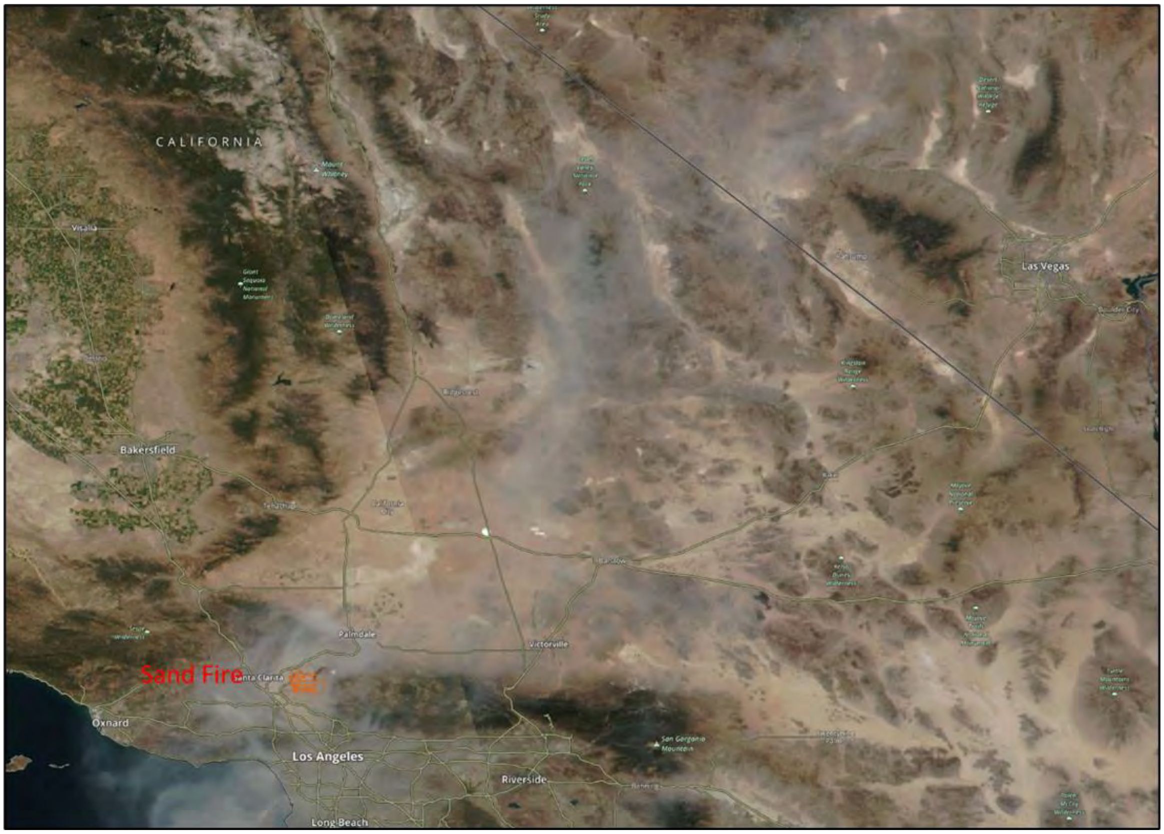

Figure 19. Visible satellite imagery of southern California and Nevada on July 23, 2016.

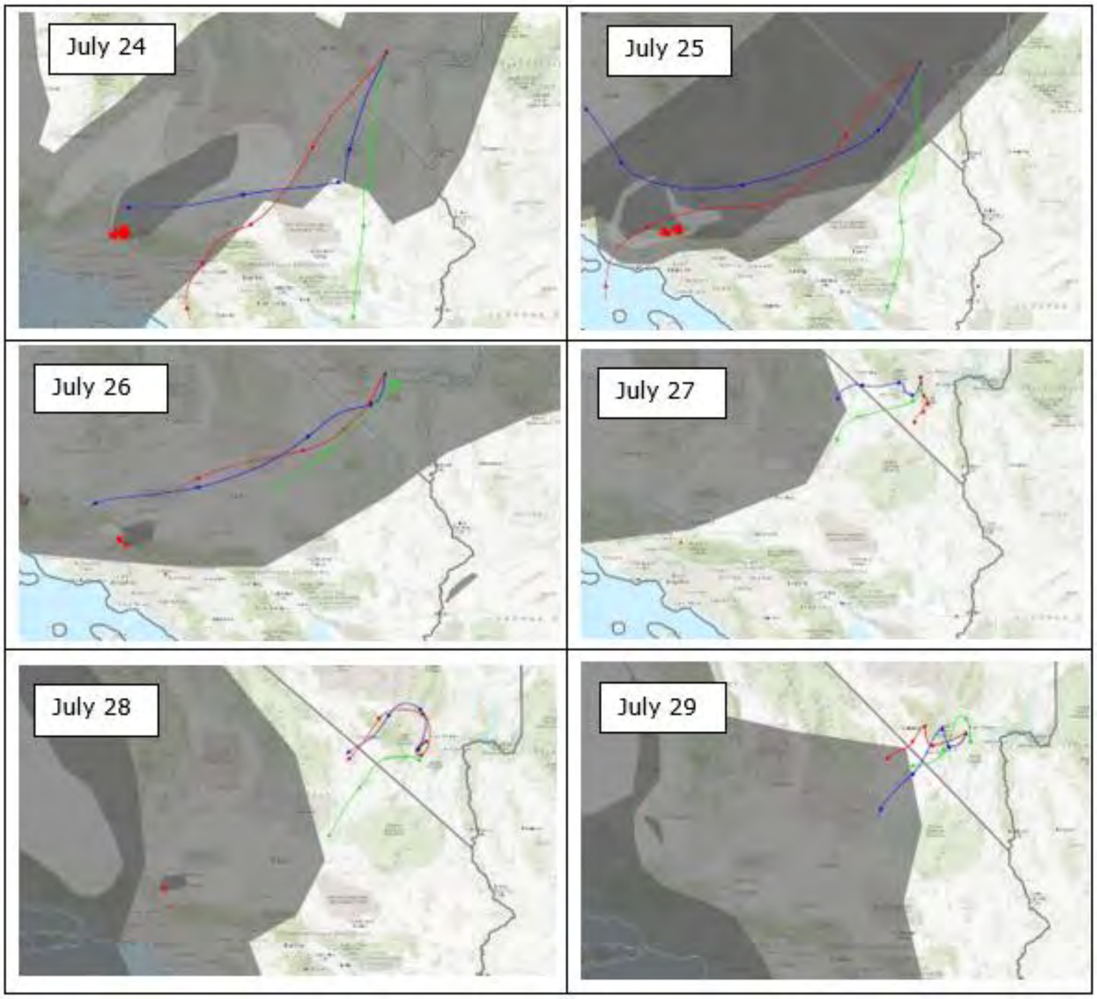

Figure 20. 24-hr backward trajectories arriving in Las Vegas at 13:00 PST on July 24-29, 2016, at altitudes of 100 m (green), 1,000 m (blue), and 2,000 m (red).

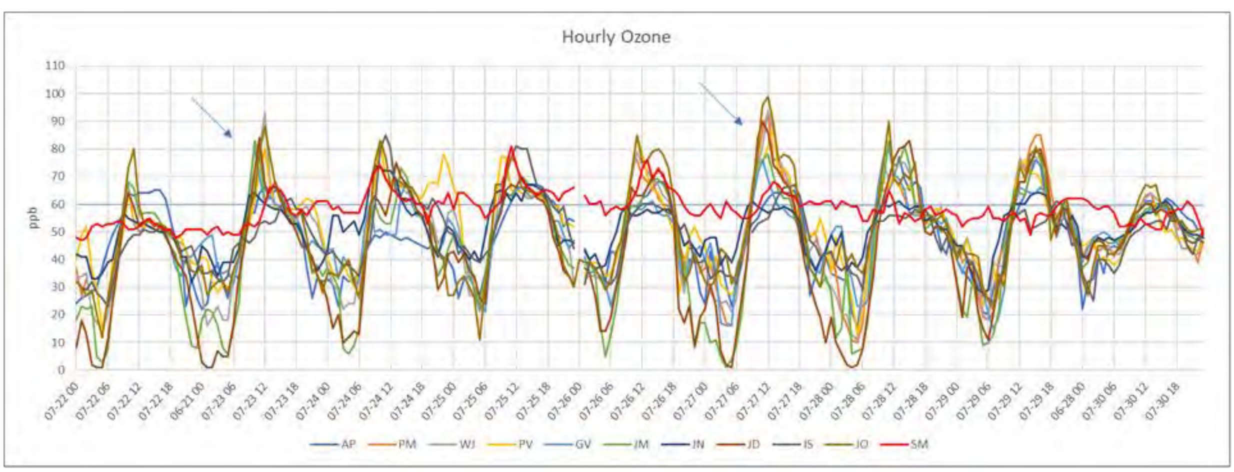

Figure 21. Time series of 1-hr ozone (ppb) at all Las Vegas Valley monitors during July 22-30, 2016.

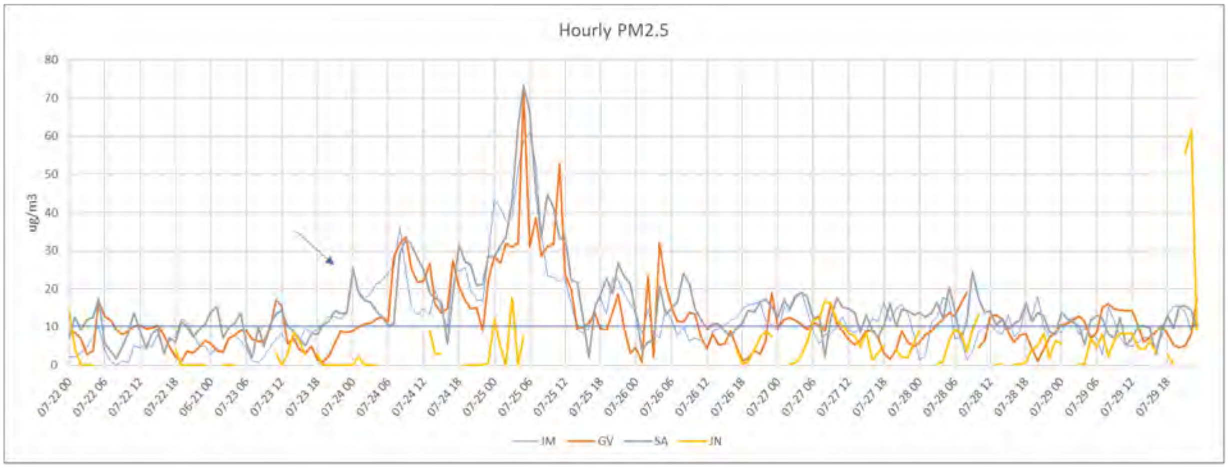

Figure 22. Time series of 1-hr $PM_{2.5}$ concentration ($\mu g/m^3$) at LVV FEM monitors during July 22-29, 2016.

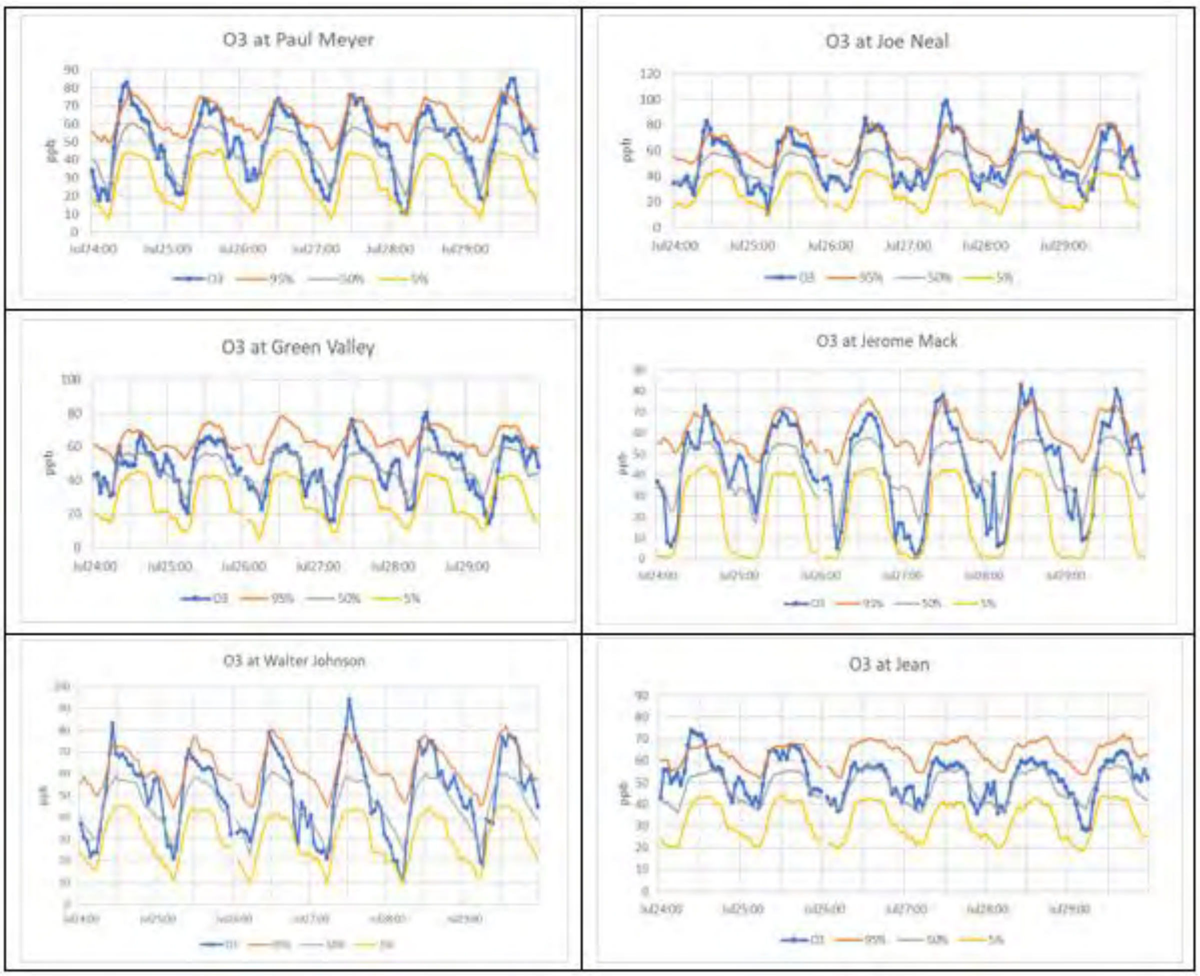

Figure 23. 6-yr hourly seasonal 95th, 50th, and 5th percentiles for ozone concentrations at the Paul Meyer, Joe Neal, Green Valley, Jerome Mack, Walter Johnson, and Jean monitoring sites during July 24-29, 2016.

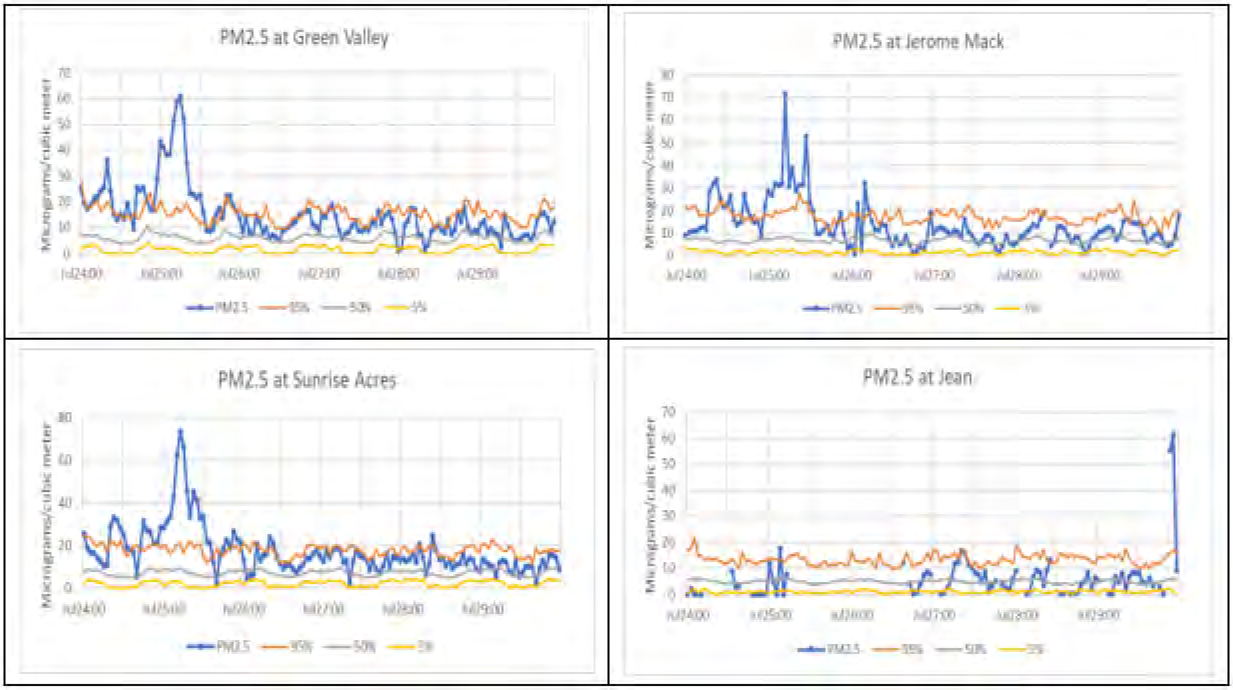

Figure 24. 6-yr hourly seasonal 95th, 50th, and 5th percentiles for $PM_{2.5}$ concentrations (µg/m^3) at LVV FEM monitors during July 24-29, 2016.

Table 4. Comparison of MDA8 ozone (ppb) during July 24-29 against 2014-2018 95th percentile MDA8 ozone.

2014-2018	PM	WJ	PV	GV	JM	JO	AP	JN
7/24		69	69	57	61	71	48	68
7/25		65	67	63	65	69	65	64
7/26	67	69	68	57	64	77	63	57
7/27	76	77	74	64	69	83	62	58
7/28	63	70	65	67	71	72	67	59
7/29	75	71	67	63	67	69	64	61
95th percentile	71	72	70	71	70	73	70	68

1.3.4 August 22-24, 2016

Clark County was impacted by smoke from multiple wildfires burning in central and southern California through much of August 2016 (Figure 25). The Soberanes fire started on July 22 as the result of an illegal campfire in Garrapata State Park, California and burned approximately 88,600 acres by August 24 with 60% containment. Ultimately, the fire burned an area of 132,127 acres when 100% containment was achieved on October 12. The Chimney fire started on the afternoon of

August 13 in the Santa Lucia Range of San Luis Obispo County, California. On August 26, the fire had grown to 45,008 acres with 47% containment. The Cedar fire started on August 16 in Kern County near Lake Isabella, California. On August 23, the fire had grown to ~21,000 acres with 5% containment. The fire burned a total of 29,322 acres by September 30 when 100% containment was achieved. The Rey fire started on August 18 in the area southeast of Lake Cachuma in Santa Barbara County, California. On August 22, the fire had grown to 23,546 acres with 20% containment. The fire burned a total of 32,606 acres by September 16 when 100% containment was achieved.

Figure 25. Locations and sizes of the Soberanes, Chimney, Cedar, and Rey Fires.

According to upper air synoptic weather patterns at 500 hPa over August 22-24 (Figure 26), a strong low-pressure trough propagated across the western U.S., followed by the buildup of a ridge over the west coast on August 24. During this period, the airflow over the LVV transitioned from northeasterly to northwesterly and had weakened by August 24.

The surface analyses for August 22-24 (Figure 27) depict a weakening cold front moved into central Nevada and stalled as a stationary front and later as a weak trough. Toward the end of the period, the thermal low reestablished over southern Nevada and central California, with hot and dry conditions in the LVV. The local daytime airflow remained light and varied from easterly through southeasterly (Figure 28).

Satellite imagery on August 22 (Figure 29) shows smoke from the Sobernanes, Chimney, Rey, and Cedar fires proceeding toward Clark County. Figure 30 shows 24-hr backward trajectories arriving in Las Vegas at 13:00 on August 22-24 at 100, 1,000 and 2,000 m, with HMS smoke maps overlaid. Smoke from multiple fires transported to the LVV during the event, especially indicated by the 2,000 m trajectories. At lower altitudes, the shorter backward trajectories reveal very low wind speeds late in the period. Figure 31 and Figure 32 show time series of 1-hr ozone and $PM_{2.5}$ during August 21-25. The $PM_{2.5}$ plot clearly shows that wildfire smoke arrived in Las Vegas on the night of August 22 and the morning of August 24. Ozone impacts are not as obvious, but ozone steadily built up over the period when additional smoke and the thermal low favoring ozone production helped to raise ozone levels. Figure 33 and Figure 34 show the hourly seasonal percentiles for ozone and $PM_{2.5}$ from 2014-2019 (May-August) compared to measured hourly ozone and $PM_{2.5}$ on August 23-24, 2016, at LVV sites and outlying site, Jean. Figure 33 shows the diurnal ozone pattern exceed 95th percentile on August 24, 2016, at the monitors in the valley and near 95th percentile at Jean. Figure 34 shows the elevated $PM_{2.5}$ exceeds 95th percentile during the evening on August 23, 2016, at Jean and few hours later right before the mid-night $PM_{2.5}$ also increased at Green Valley and Sunrise Acres. Moreover, the level of $PM_{2.5}$ had gradually increased at all sites in the LVV and Jean, especially with far beyond 95th percentile. All figures support the conclusion that wildfire smoke had been transported to the LVV.

The LVV was often impacted by smoke from multiple wildfires burning in central and southern California through much of August 2016. When the weather pattern evolved to suppress ventilation and dilution later in the period, ozone increased to extreme values. Table 5 compares MDA8 ozone with historical summer 95th percentile MDA8 ozone from 2014 to 2018 at monitoring sites with sufficient data. On August 24, MDA8 ozone exceeded the 95th percentile at the Paul Meyer, Walter Johnson, Palo Verde, Jerome Mack, and Joe Neal monitoring sites.

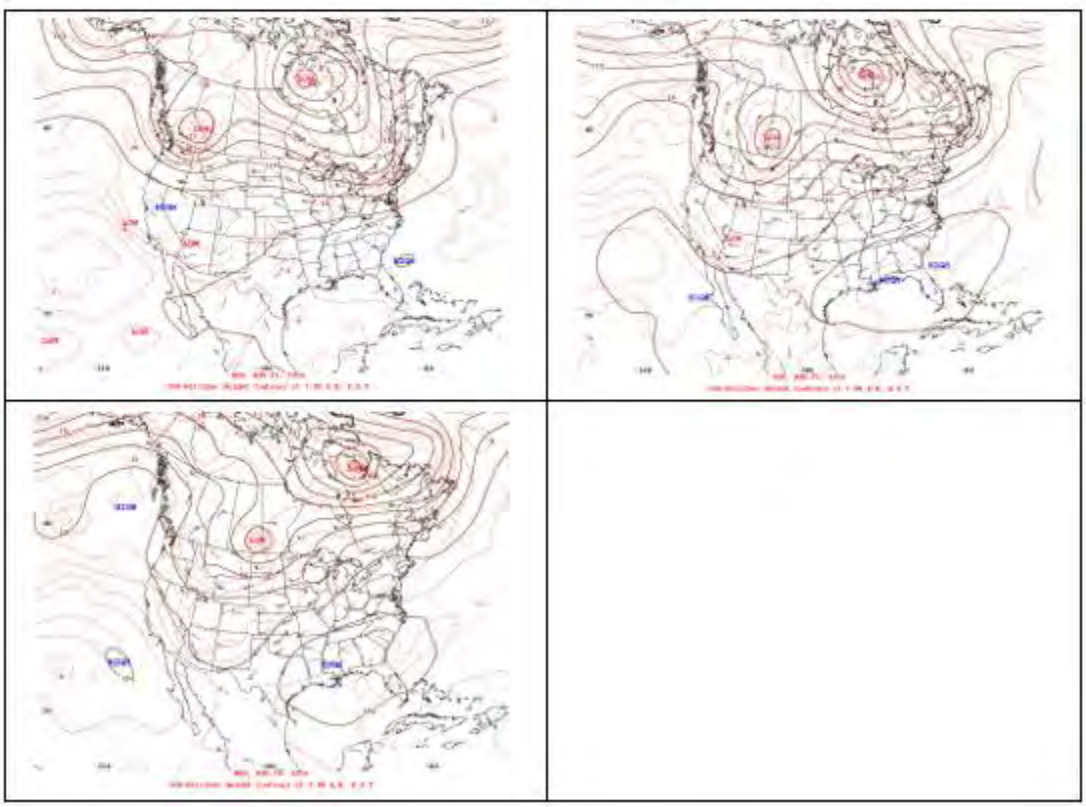

Figure 26. 500 hPa (approximately 5,500 m) weather patterns at 07:00 EST (04:00 PST) from August 22 to 24, 2016.

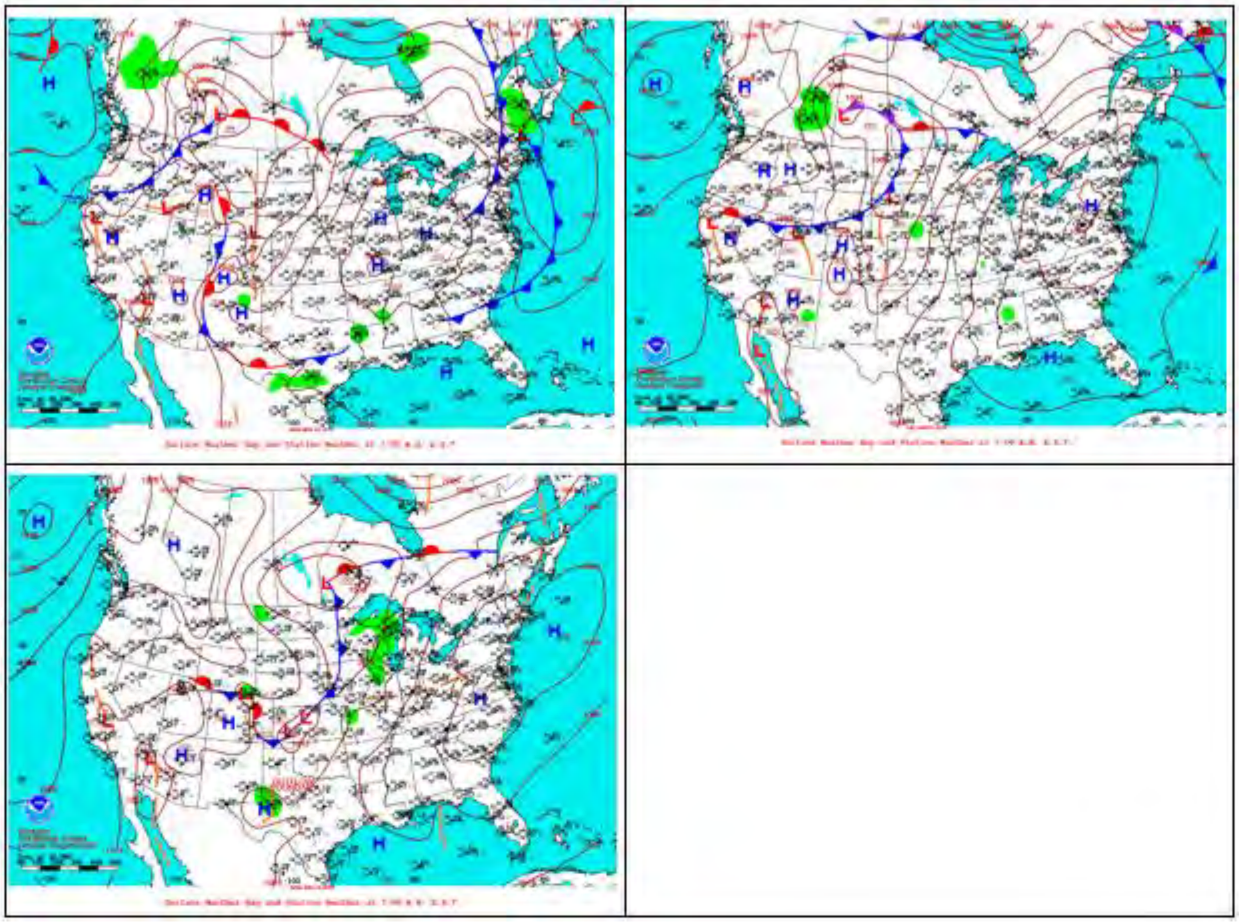

Figure 27. Surface weather patterns at 07:00 EST (04:00 PST) from August 22 to 24, 2016.

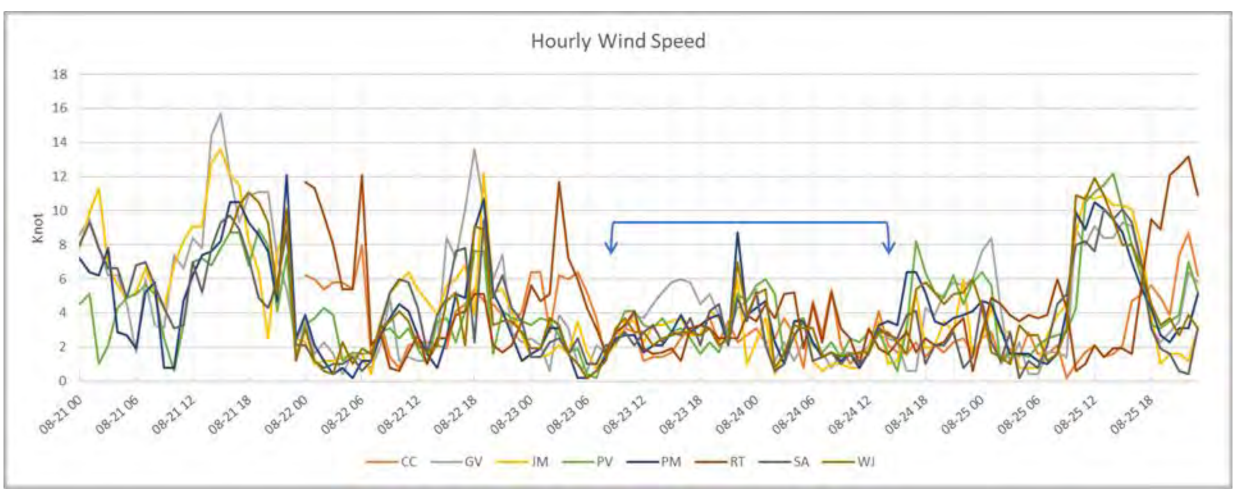

Figure 28. Time series of 1-hr wind speed (knots) at all monitors in the LVV from August 21 to 25, 2016.

Figure 29. Visible satellite imagery of Central and Southern California and Nevada on August 22, 2016.

Figure 30. 24-hr backward trajectories arriving in Las Vegas at 13:00 PST on August 22-24, 2016, at altitudes of 100 m (green), 1,000 m (blue), and 2,000 m (red).

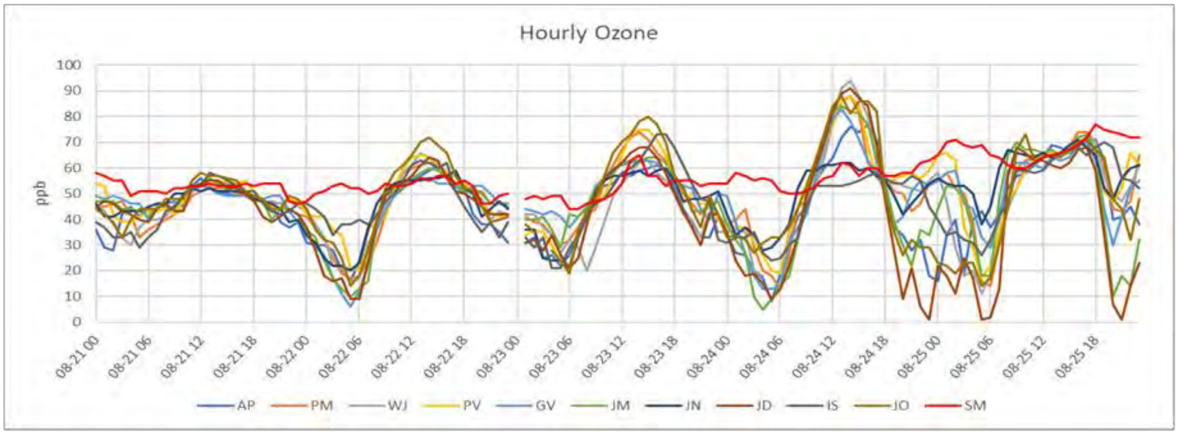

Figure 31. Time series of 1-hr ozone (ppb) at all LVV monitors during August 21-25, 2016.

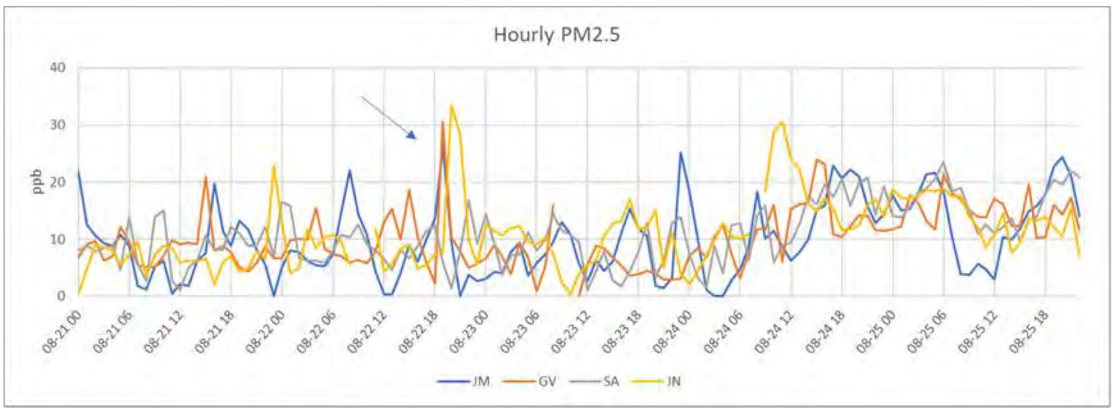

Figure 32. Time series of 1-hr $PM_{2.5}$ concentration (µg/m^3) at LVV FEM monitors during August 21-25, 2016.

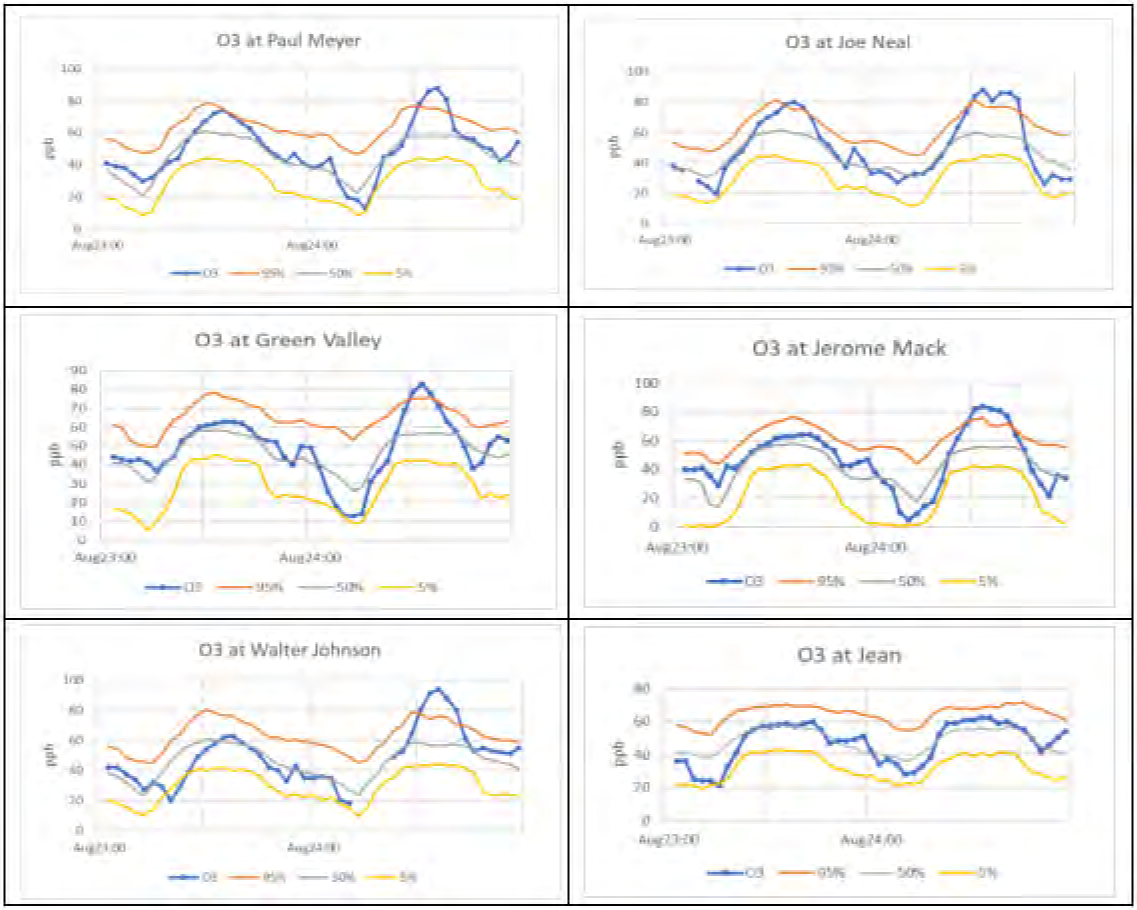

Figure 33. 6-yr hourly seasonal 95th, 50th, and 5th percentiles for ozone concentrations at the Paul Meyer, Joe Neal, Green Valley, Jerome Mack, Walter Johnson, and Jean monitoring sites during August 23-24, 2016.

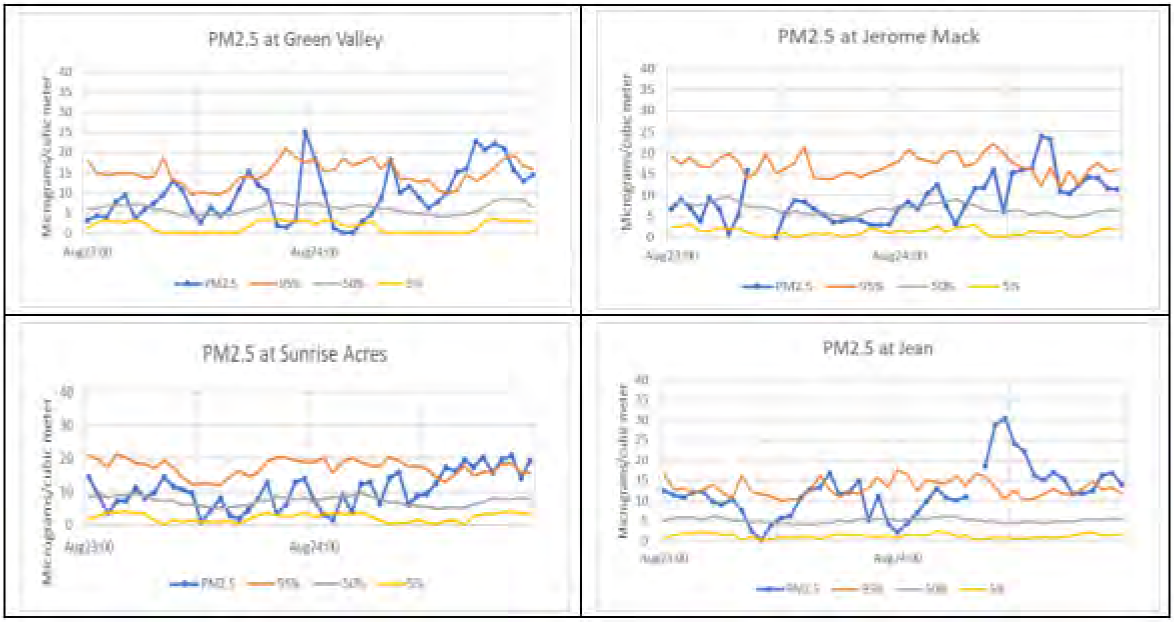

Figure 34. 6-yr hourly seasonal 95th, 50th, and 5th percentiles for $PM_{2.5}$ concentrations (µg/m³) at LVV FEM monitors during August 23-24, 2016.

Table 5. Comparison of MDA8 ozone (ppb) during August 22-24, 2016, against 2014-2018 95th percentile MDA8 ozone.

2014-2018	PM	WJ	PV	GV	JM	JO	AP	JN
8/23	66	56	67	60	61	71	57	57
8/24	71	76	73	69	75	80	68	60
95th percentile	71	72	70	71	70	73	70	68

2. 2018 Ozone Exceptional Events

Thirteen dates in 2018 were found to be exceptional events, and demonstrations were prepared and submitted to EPA Region 9 in 2021 that all received a "Deferred Review" status on April 11, 2022. The Clark County Department of Environment & Sustainability (DES) is submitting a request to exclude data from these dates on this basis for the following case explicitly defined in the U.S. Environmental Protection Agency (EPA) memo "Clarification Memo on Additional Methods, Determinations, and Analyses to Modify Air Quality Data Beyond Exceptional Events": "Estimating base and future-year design values ozone SIP attainment demonstrations," as a part of DES' State Implementation Plan (SIP). As stated in the memo, the EPA or the appropriate reviewing authority will determine whether the air agency—in this case, Clark County DES—has appropriately documented and justified the data exclusion and/or adjustment when it acts on a SIP submission. **Table 6** provides the links to all 2018 Exceptional Event demonstrations that provide evidence of wildfire smoke impacts on ozone concentrations during the period of June-August 2018 and meet the criteria as defined in the document and guidance. This evidence is included as part of Clark County's request to exclude these data from base and future-year design values as a part of their SIP.

The wildfire smoke events presented in the Exceptional Events demonstrations resulted in ozone measurements that were extreme and nonrepresentative of past and future days for Clark County, Nevada. The *Guideline on Air Quality Models* (40 CFR Part 51, Appendix W) states "control agencies have long expressed a need for consistency in the application of air quality models for regulatory purposes…the expanded requirements for models to cover even more complex problems have emphasized the need for period review and update of guidance on these techniques". Wildfire smoke events are one such complex problem, as wildfire season has extended and encompasses the summer months, which are also considered to be ozone production season. Wildfire occurrence is wildly considered to be a stochastic, natural phenomenon, and is therefore inconsistent year-to-year. Downstream smoke impacts, including ozone formation, are not typical nor representative of the ambient conditions of Clark County, NV. Based on the evidence provided, we formally request exclusion of the following dates in base and projected ozone design values.

Table 6. Links to Exceptional Event demonstrations and associated appendices for all 2018 dates removed from base and future-year design values for ozone SIP attainment.

Event Date	Link to Exceptional Event Demonstrations
June 23, 2018	**Main Document:** https://www.clarkcountynv.gov/Environmental%20Sustainability/Exceptional%20Events/20180623_ClarkCounty_Wildfire_EE.pdf **Appendices:** https://www.clarkcountynv.gov/Environmental%20Sustainability/Exceptional%20Events/20180623_ClarkCounty_Wildfire_EE_Appendix.pdf
June 27, 2018	**Main Document:** https://www.clarkcountynv.gov/Environmental%20Sustainability/Exceptional%20Events/20180627_ClarkCounty_Wildfire_EE.pdf **Appendices:** https://www.clarkcountynv.gov/Environmental%20Sustainability/Exceptional%20Events/20180627_ClarkCounty_Wildfire_EE_Appendix.pdf
July 14-17, 2018	**Main Document:** https://www.clarkcountynv.gov/Environmental%20Sustainability/Exceptional%20Events/20180714-17_ClarkCounty_Wildfire_EE.pdf **Appendices:** https://www.clarkcountynv.gov/Environmental%20Sustainability/Exceptional%20Events/20180714-17_ClarkCounty_Wildfire_EE_Appendix.pdf
July 25-27, 2018	**Main Document:** https://www.clarkcountynv.gov/Environmental%20Sustainability/Exceptional%20Events/20180725-27_ClarkCounty_Wildfire_EE.pdf **Appendices:** https://www.clarkcountynv.gov/Environmental%20Sustainability/Exceptional%20Events/20180725-27_ClarkCounty_Wildfire_EE_Appendix.pdf
July 30-31, 2018	**Main Document:** https://www.clarkcountynv.gov/Environmental%20Sustainability/Exceptional%20Events/20180730-31_ClarkCounty_Wildfire_EE.pdf **Appendices:** https://www.clarkcountynv.gov/Environmental%20Sustainability/Exceptional%20Events/20180730-31_ClarkCounty_Wildfire_EE_Appendix.pdf
August 6-7, 2018	**Main Document:** https://www.clarkcountynv.gov/Environmental%20Sustainability/Exceptional%20Events/20180806-07_ClarkCounty_Wildfire_EE.pdf **Appendices:** https://www.clarkcountynv.gov/Environmental%20Sustainability/Exceptional%20Events/20180806-07_ClarkCounty_Wildfire_EE_Appendix.pdf

3. 2020 Ozone Exceptional Events

Seven dates in 2020 were found to be exceptional events, and demonstrations were prepared and submitted to EPA Region 9 in 2021 that received a "Deferred Review" status on April 11, 2022. The Clark County Department of Environment & Sustainability (DES) is submitting a request to exclude data from these dates on this basis for the following case explicitly defined in the U.S. Environmental Protection Agency (EPA) memo "Clarification Memo on Additional Methods, Determinations, and Analyses to Modify Air Quality Data Beyond Exceptional Events": "Estimating base and future-year design values ozone SIP attainment demonstrations," as a part of DES' State Implementation Plan (SIP). As stated in the memo, the EPA or the appropriate reviewing authority will determine whether the air agency—in this case, Clark County DES—has appropriately documented and justified the data exclusion and/or adjustment when it acts on a SIP submission. **Table 7** provides the links to all 2020 Exceptional Event demonstrations that provide evidence of wildfire smoke impacts on ozone concentrations during the period of August-September 2020 and meet the criteria as defined in the document and guidance. This evidence is included as part of Clark County's request to exclude these data from base and future-year design values as a part of their SIP.

The wildfire smoke events presented in the Exceptional Events demonstrations resulted in ozone measurements that were extreme and nonrepresentative of past and future days for Clark County Nevada. The *Guideline on Air Quality Models* (40 CFR Part 51, Appendix W) states "control agencies have long expressed a need for consistency in the application of air quality models for regulatory purposes…the expanded requirements for models to cover even more complex problems have emphasized the need for period review and update of guidance on these techniques". Wildfire smoke events are one such complex problem, as wildfire season has extended and encompasses the summer months, which are also considered to be ozone production season. Wildfire occurrence is wildly considered to be a stochastic, natural phenomenon, and is therefore inconsistent year-to-year. Downstream smoke impacts, including ozone formation, are not typical nor representative of the ambient conditions of Clark County, Nevada. Based on the evidence provided, we formally request exclusion of the following dates in base and projected ozone design values.

Table 7. Links to Exceptional Event demonstrations and associated appendices for all 2020 dates removed from base and future-year design values for ozone SIP attainment.

Event Date	Link to Exceptional Event Demonstrations
August 3, 2020	**Main Document:** https://www.clarkcountynv.gov/Environmental%20Sustainability/Exceptional%20Events/20200803_ClarkCounty_Wildfire_EE.pdf **Appendices:** https://www.clarkcountynv.gov/Environmental%20Sustainability/Exceptional%20Events/20200803_ClarkCounty_Wildfire_EE_Appendix.pdf
August 7, 2020	**Main Document:** https://www.clarkcountynv.gov/Environmental%20Sustainability/Exceptional%20Events/20200807_ClarkCounty_Wildfire_EE.pdf **Appendices:** https://www.clarkcountynv.gov/Environmental%20Sustainability/Exceptional%20Events/20200807_ClarkCounty_Wildfire_EE_Appendix.pdf
August 18-21, 2020	**Main Document:** https://www.clarkcountynv.gov/Environmental%20Sustainability/Exceptional%20Events/20200818-21_ClarkCounty_Wildfire_EE.pdf **Appendices:** https://www.clarkcountynv.gov/Environmental%20Sustainability/Exceptional%20Events/20200818-21_ClarkCounty_Wildfire_EE_Appendix.pdf
September 26, 2020	**Main Document:** https://www.clarkcountynv.gov/Environmental%20Sustainability/Exceptional%20Events/20200926_ClarkCounty_Wildfire_EE.pdf **Appendices:** https://www.clarkcountynv.gov/Environmental%20Sustainability/Exceptional%20Events/20200926_ClarkCounty_Wildfire_EE_Appendix.pdf

4. 2021 Ozone Technical Supporting Documents

The U.S. Environmental Protection Agency (EPA) published the memo *Clarification Memo on Additional Methods, Determinations, and Analyses to Modify Air Quality Data Beyond Exceptional Events*[2] (the memo), which illustrates cases where air quality data may be modified for certain regulatory determinations, actions, and analysis. The document defines cases where a request to exclude data can be made through the Exceptional Events Rule, such as when a National Ambient Air Quality Standard (NAAQS) design value is recalculated in EPA's Air Quality System (AQS) using modified data to determine attainment. The document also defines additional analyses that are not covered in the Exceptional Events Rule, where submitting modified data may be appropriate. These additional cases that are not covered in the Exceptional Event Rule are defined as conditions where ambient air quality data may have been "influenced by an atypical, extreme or unrepresentative event." The Clark County Department of Environment & Sustainability (DES) is submitting a request to exclude data on this basis for the following case explicitly defined in the document: "Estimating base and future-year design values ozone SIP attainment demonstrations" as a part of their State Implementation Plan (SIP).

The EPA document states that monitoring data could qualify for exclusion if "[A]mbient data are not representative to characterize background or base period concentrations in accordance with the *Guideline*," in reference to *Guideline on Air Quality Models*, 40 CFR Part 51, Appendix W. Extreme wildfire events are increasingly prevalent in the western United States (U.S.), resulting in increased smoke impacts. Clark County, Nevada, was impacted by wildfire smoke from local and regional sources in the summer of 2021 (**Table 8**). Following an atypical smoke intrusion, high ozone concentrations were measured as a result of direct transport and secondary photochemical processes.

As stated in the memo, EPA or the appropriate reviewing authority will determine whether the air agency—in this case, Clark County DES—has appropriately documented and justified the data exclusion and/or adjustment when it acts on a SIP submission. The following documentation is provided to demonstrate that seven local and regional wildfire smoke events in the period of June-September 2021 meet the criteria as defined in the document and guidance. This evidence is included as part of Clark County's request to exclude these data from base and future-year design values for ozone SIP attainment demonstrations as a part of their SIP.

[2] https://www.epa.gov/sites/default/files/2019-04/documents/clarification_memo_on_data_modification_methods.pdf

Table 8. Summary of events requested for exclusion from ozone SIP base and future-year design values.

Event Date	Event Ozone Concentration Percentile	Sites Exceeded During Event	Type of Event
June 11-12, 2021	93rd – 97th	6 sites: Green Valley, Joe Neal, Palo Verde, Paul Meyer, Walnut Community Center, and Walter Johnson	Local Smoke
June 16-17, 2021	>95th	5 sites: Palo Verde, Joe Neal, Paul Meyer, Walter Johnson, and Mountains Edge Park	Regional Smoke
July 20, 2021	93rd – 98th	4 sites: Green Valley, Joe Neal, Walnut Community Center, and Walter Johnson	Regional Smoke
August 2-3, 2021	96th – 99.5th	8 sites: Green Valley, Jerome Mack-NCore, Joe Neal, Liberty High School, Mountains Edge Park, Palo Verde, Paul Meyer, and Walter Johnson	Regional Smoke
August 7, 2021	99th – 100th	12 sites: Green Valley, Indian Springs, Jean, Jerome Mack-NCore, Noe Neal, Liberty High School, Mountains Edge Park, Palo Verde, Paul Meyer, Virgin Valley High School, and Walter Johnson	Regional Smoke
August 19, 2021	97th – 99th	5 sites: Joe Neal, Palo Verde, Paul Verde, Walnut Community Center, and Walter Johnson	Regional Smoke
September 8, 2021	96th	2 sites: Palo Verde and Walter Johnson	Regional Smoke

4.1 June 11-12, 2021

4.1.1 Event Summary

The unrepresentative ozone event took place on June 11-12, 2021, and affected six sites in Clark County, Nevada: Green Valley, Joe Neal, Palo Verde, Paul Meyer, Walnut Community Center, and Walter Johnson. The maximum daily 8-hr average (MDA8) concentrations at the effected sites ranged from 71-73 ppb: 73 ppb at Joe Neal, 72 ppb at each of Paul Meyer, Walnut Community Center, and Walter Johnson, and 71 ppb at Green Valley on June 11, and 71 ppb at Palo Verde and Walter Johnson on June 12. Time series graphs showing hourly ozone concentrations that exceeded the seasonal means (calculated using May 1 – October 31, 2017-2021) and 10th-90th percentiles at each site are shown in **Figure 35**.

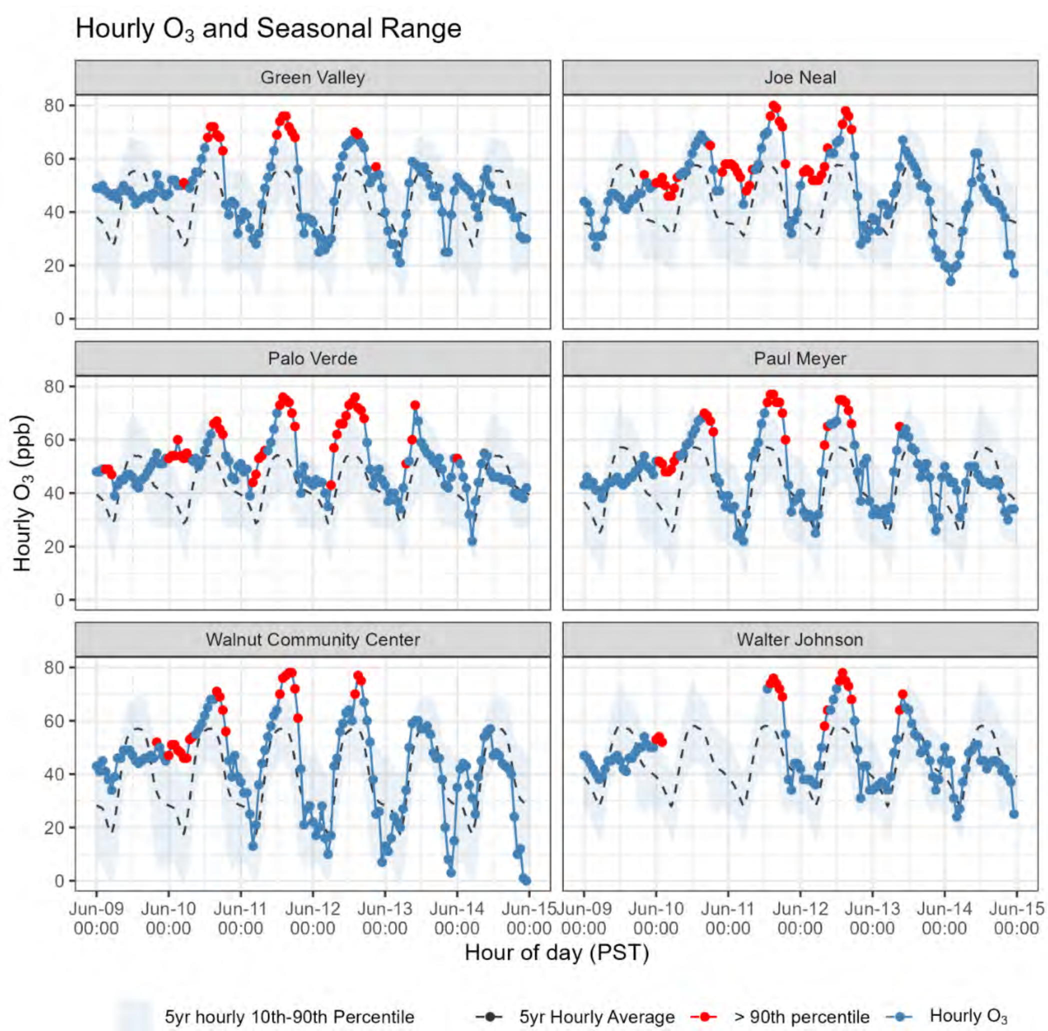

Figure 35. Hourly ozone concentrations (ppb) compared to 5-yr ozone season (May 1 – October 31) hourly means and 10-90th percentiles. Note: data from the Walnut Community Center site are only available for June 1 – October 31, 2021.

On June 11, hourly ozone measurements at many sites, such as Joe Neal, Palo Verde, and Walnut Community Center, were already greater than 10% above the mean seasonal values during the overnight hours. Measurements exceeded the 90th percentiles between 12:00 to 19:00 PST for most sites, and as early as 0:00 – 04:00 PST at the Joe Neal and Palo Verde sites, indicative of overnight transport of ozone and ozone precursors from a nearby wildfire. In general, measurements returned below the 90th percentile on June 12 at 17:00 PST.

The local Sandy Valley Fire southwest of Las Vegas was identified as a major contributor to this event. Evidence includes (1) HYSPLIT dispersion modeling and meteorological analysis showing accumulation of smoke in Clark County, (2) visible smoke in camera images and video news coverage; (3) elevated $PM_{2.5}$, CO, and NO_2 concentrations; and (4) a spike in the $PM_{2.5}$-to-PM_{10} ratio observed immediately after the fire became active. This combination of evidence indicates that this is an unrepresentative event for base and future design value ozone assessments.

4.1.2 Identification of Wildfires

A local fire was active during June 11-12, the exclusion days. The Sandy Valley Fire was first reported at 13:34 PST on June 10[3] and grew to approximately 700 acres during the first day of burning. The fire expanded to its full size of 1,380 acres (originally estimated at 1,600 acres) by June 11, 2021.[4] Full containment of the fire was achieved on June 20, based on data from the Wildland Fire Interagency Geospatial Services (WFIGS) Current Interagency Fire Perimeters[5] (Figure 36). The fire was in close proximity to the Las Vegas metropolitan region, about 20 km to the west (Figure 37).

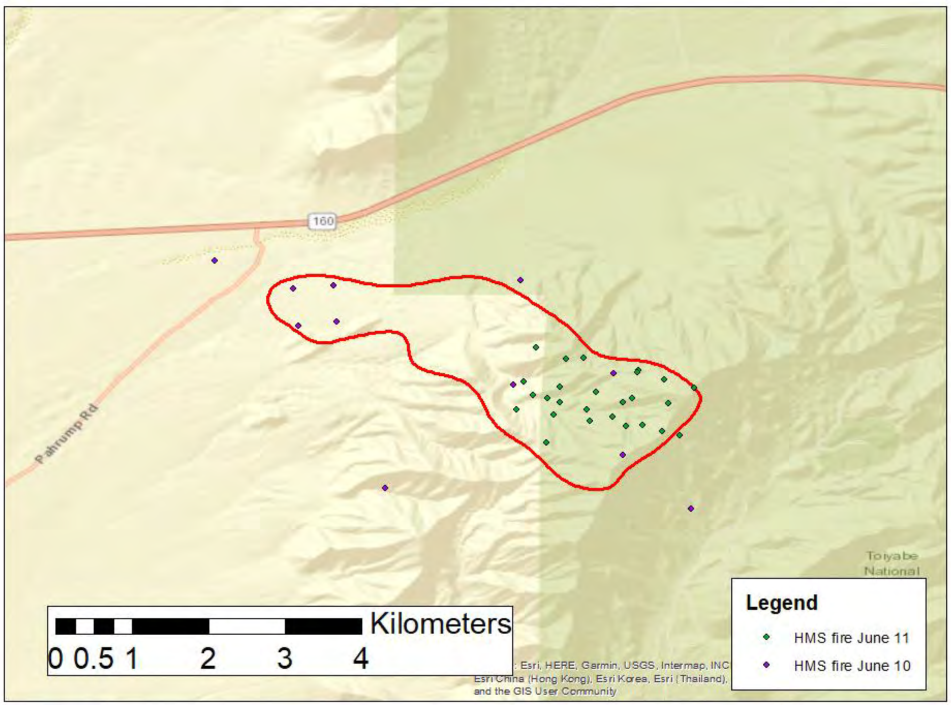

Figure 36. Sandy Valley Fire perimeter and active fire detections from June 10 and 11, 2021. From the National Oceanic and Atmospheric Administration (NOAA)'s Hazard Mapping System (HMS).

[3] https://data-nifc.opendata.arcgis.com/maps/wfigs-interagency-fire-perimeters (fire value 2021-NVSND-500708)

[4] https://www.ktnv.com/news/crews-respond-to-fire-southwest-of-las-vegas-near-sandy-valley-road-highway-160

[5] McClure et al. (2023) Consistent, high-accuracy mapping of daily and sub-daily wildfire growth with satellite observations. International Journal of Wildland Fire 32, 694-708. Available at https://www.publish.csiro.au/wf/ExportCitation/WF22048.

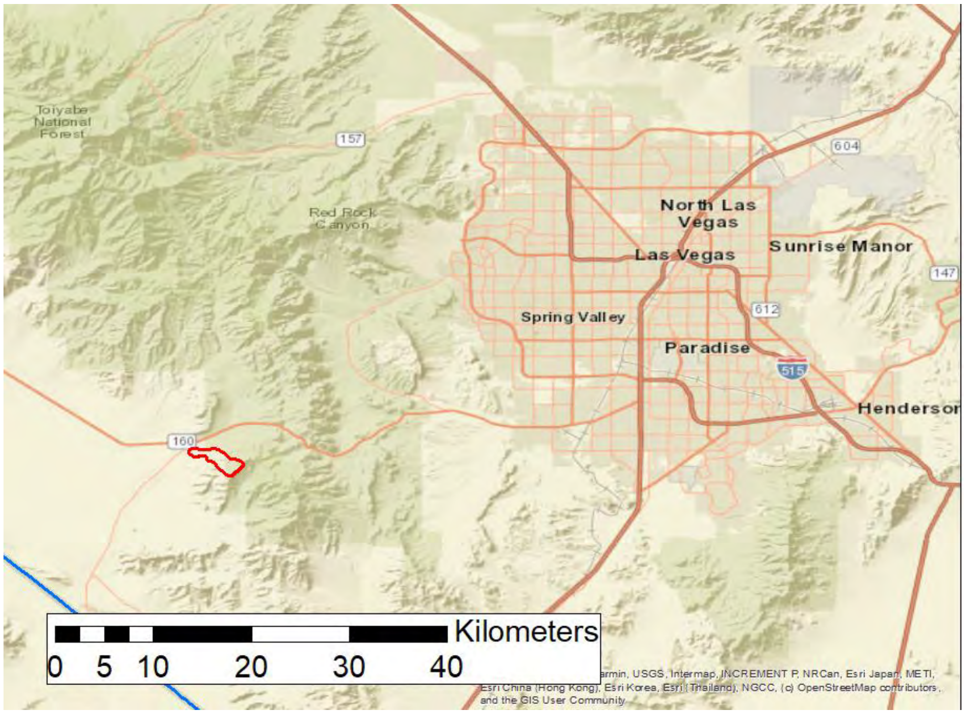

Figure 37. Sandy Valley Fire perimeter with HMS fire detections in proximity to Las Vegas, NV.

4.1.3 Dispersion Modeling and Regional Analysis

HYSPLIT dispersion modelling was performed and covered the period of June 10 through June 12, 2021. Dispersion was initiated from the location of the Sandy Valley Fire based on satellite hot spot retrievals at 14:00 PST on June 10 (to coincide with the ignition of the Sandy Valley Fire). High Resolution Rapid Refresh (HRRR) data at 3 km horizontal resolution was used for meteorological input. A high-resolution meteorological dataset was required for this event due to the proximity of the fire to Clark County. Output from the dispersion modeling at 0-100 m is shown in **Figure 38**. The first 12 hours of dispersion is shown in the left panel (June 10 at 14:00 through June 11 at 02:00 PST), indicating that most of the smoke from the fire initially entered the Las Vegas valley from the mountain pass between the Spring Mountains and McCullough Range. This smoke passed through the Jean monitoring station as it entered the valley. The middle panel shows the next 24 hours of dispersion (June 11 at 02:00 through June 12 at 02:00 PST), and the right panel shows the final 18 hours of dispersion (June 12 at 02:00 through June 12 at 20:00 PST). Both panels indicate that smoke from the Sandy Valley fire had entered the valley and was present in the lower mixed layer, impacting the surface conditions.

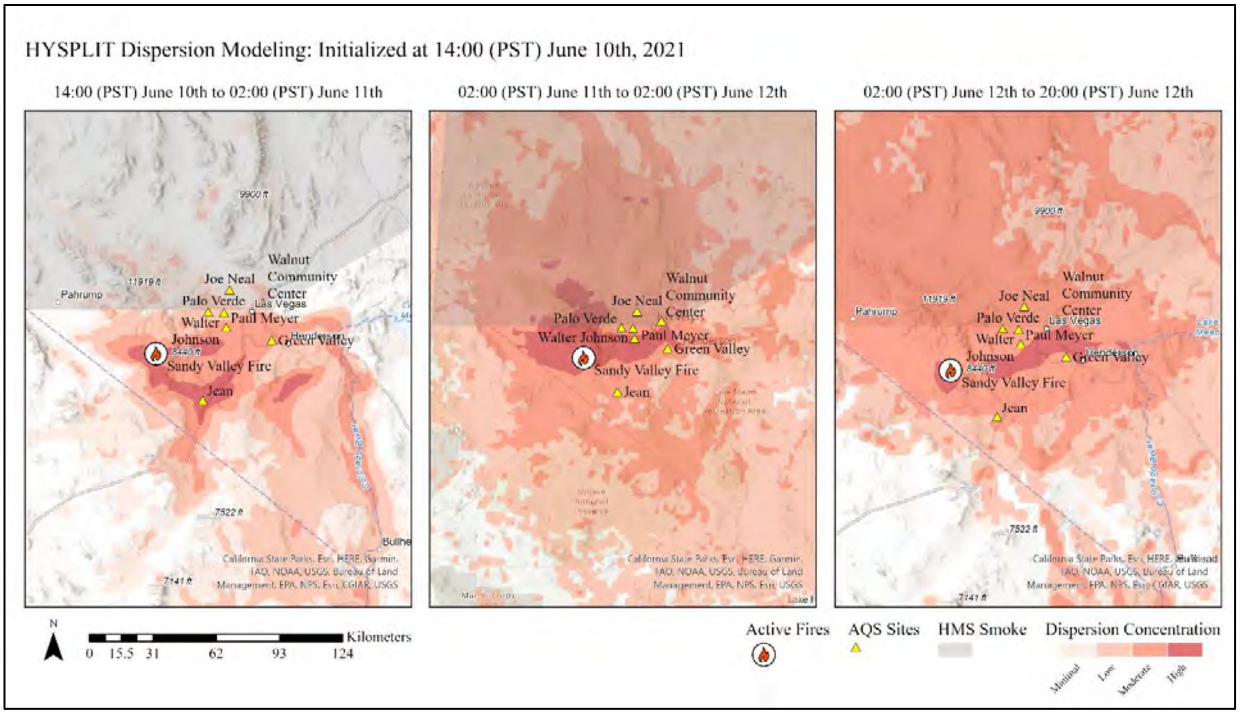

Figure 38. HYSPLIT dispersion modeling from the Sandy Valley Fire (labeled as "Active Fires"). HRRR 3 km meteorological data was used, and dispersion was initiated on June 10 at 14:00 PST to correspond with the ignition of the Sandy Valley Fire. The left panel shows the first 12 hours of dispersion after ignition, the middle panel shows the next 24 hours of dispersion, and the right panel shows the last 18 hours of dispersion. Clark County monitoring sites are labeled as yellow triangles. HMS smoke is shown as a grey polygon. In this case, the HMS smoke data satellite product did not capture the hyperlocal surface impacts of the Sandy Valley Fire.

Several meteorological factors were evaluated to determine the potential for smoke impacts on ozone concentrations in the Las Vegas region on June 11-12. These factors include boundary layer heights, upper-level winds, HYSPLIT back trajectories from the Las Vegas area, and surface winds.

Given the fire ignition time of 13:34 PST on June 10, boundary layer height data were assessed for the evening of June 10 to determine the extent of upper-level winds to be investigated for smoke transport into the Las Vegas area. Figure 39 shows mixing heights from the 00:00 UTC sounding on June 11 (16:00 PST on June 10) reached approximately 700 mb (3,139 m).

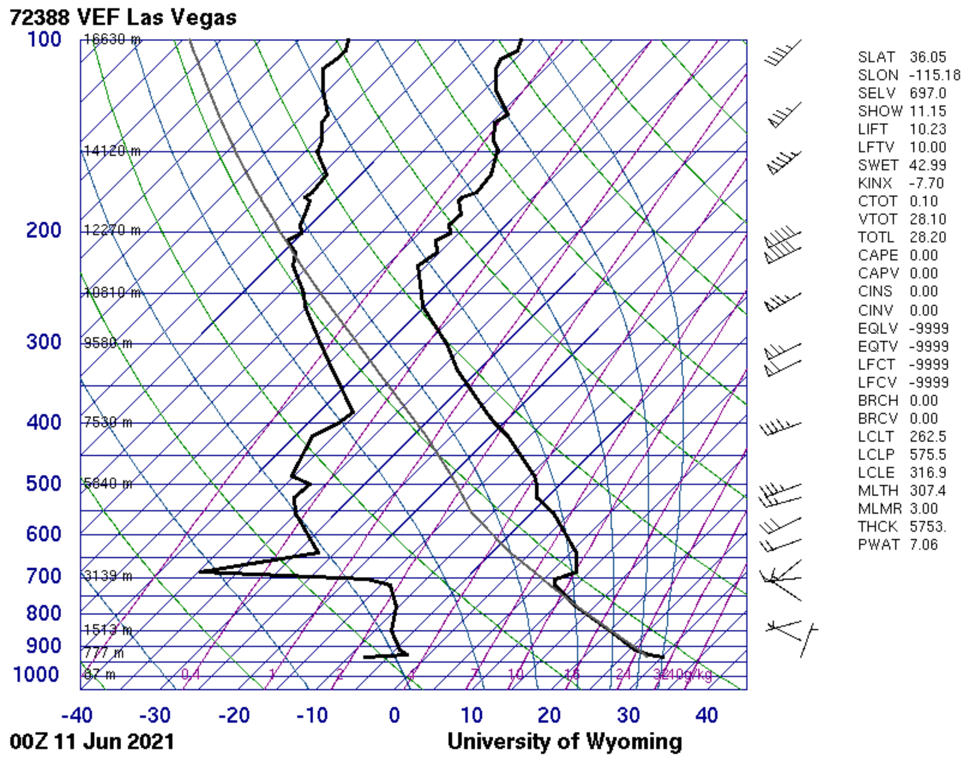

Figure 39. Sounding from Las Vegas, NV, at 00:00 UTC on June 11 (16:00 PST on June 10), 2021.

Based on these mixing heights, upper-level winds from 925 mb to 700 mb were examined for potential smoke transport. The 700 mb weather pattern featured an upper-level trough along the West Coast, and a weak ridge of high pressure over the Four Corners region, with westerly winds at 10 knots over the Las Vegas region at 00:00 UTC on June 11 (Figure 40). This pattern was conducive to smoke transport from the Sandy Valley Fire located to the west-southwest of Las Vegas.

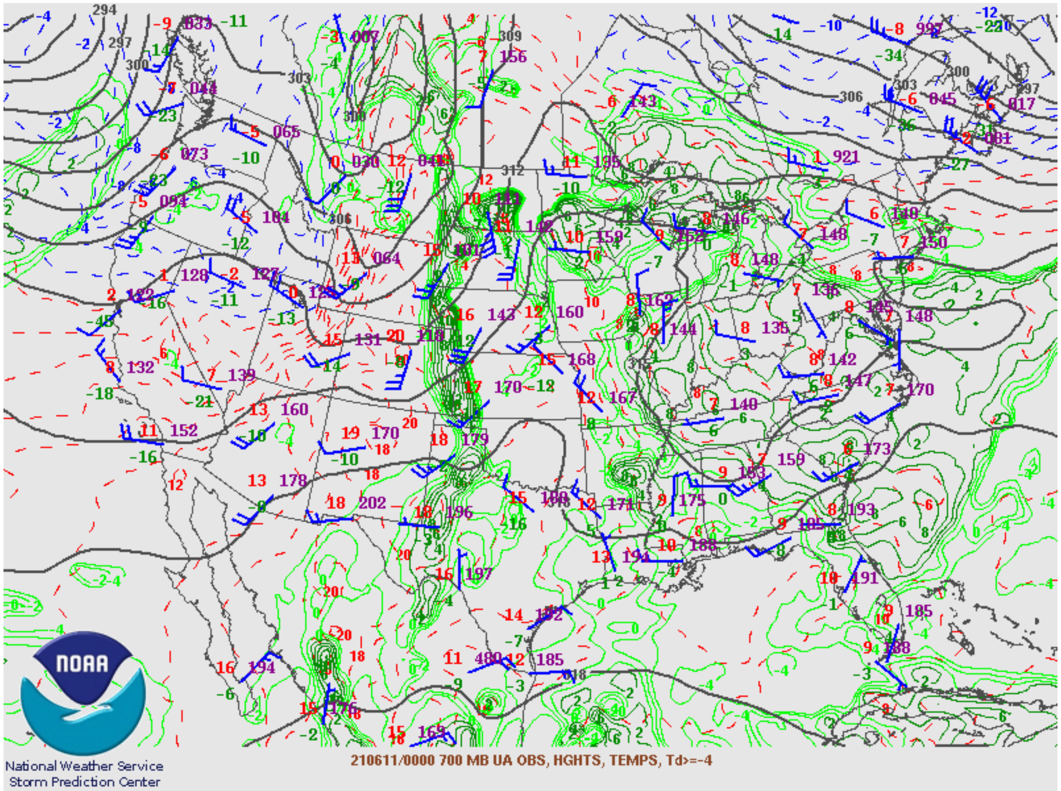

Figure 40. 700-mb map for 00:00 UTC on June 11, 2021 (16:00 PST on June 10, 2021).

As the Sandy Valley Fire ignited around 20:00 UTC (12:00 PST) on June 10, HYSPLIT back trajectories were computed from 00:00 UTC on June 11 (16:00 PST on June 10) back to 20:00 UTC (12:00 PST) on June 10 using HRRR meteorology in Las Vegas at heights of 10 meters, 1,500 meters, and 3,000 meters (Figure 41). The path of the 3,000-meter back trajectory goes directly across the location of the Sandy Valley Fire, implying smoke advection over Las Vegas near the top of the boundary layer on the evening of June 10. In addition, with low-level mixing reaching slightly above 3,000 meters, there was potential for the fumigation process to mix smoke down to the surface.

The upper-level weather pattern remained consistent through June 11, with westerly winds around 10 knots at 700 mb continuing to push smoke toward the Las Vegas region and lighter winds limiting advection near the surface at 00:00 UTC on June 12 (16:00 PST on June 11) (Figure 42).

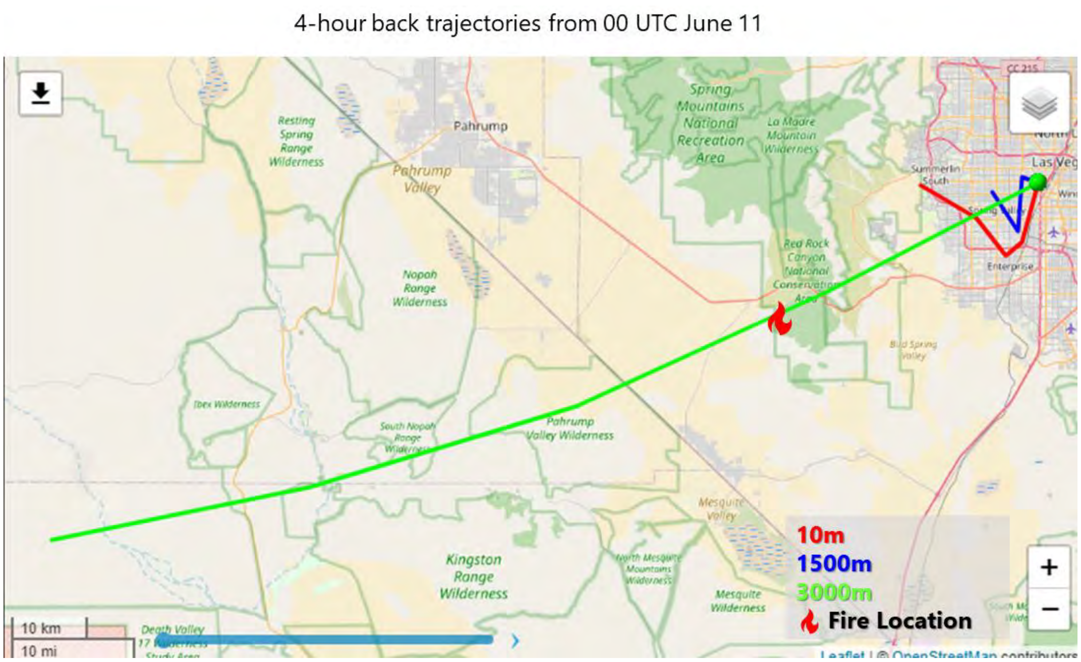

Figure 41. HYSPLIT back trajectories from 10, 1,500, and 3,000 meters using HRRR 3-km meteorological data and initiated at 00:00 UTC on June 11 back through 20:00 UTC on June 10 (16:00 PST on June 10 back through 12:00 PST on June 10).

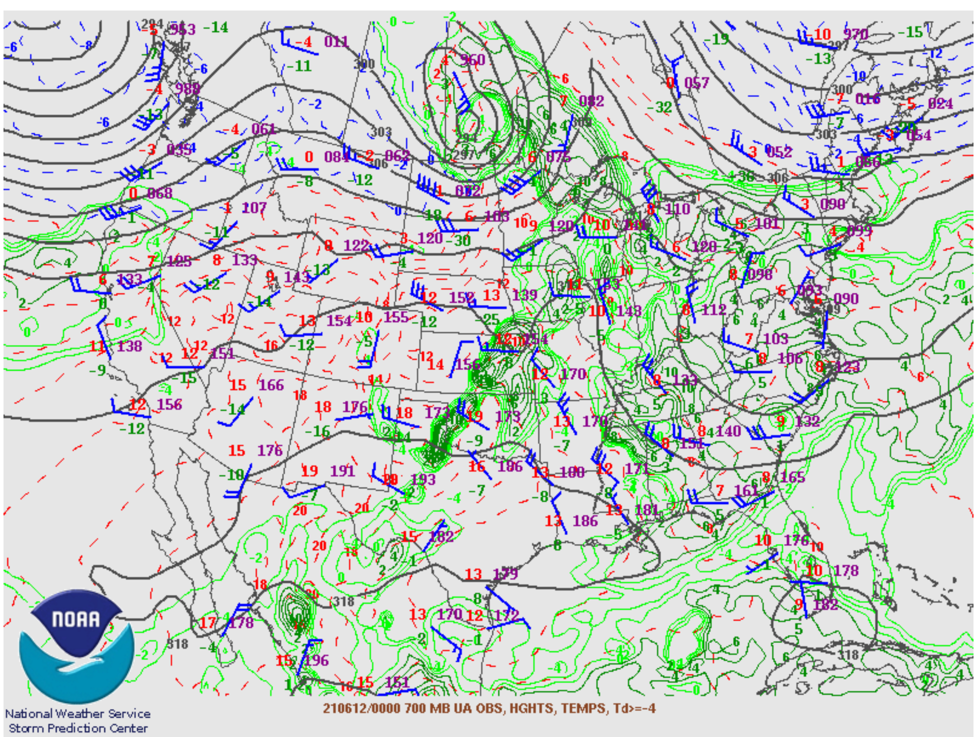

Figure 42. 700-mb map valid 00:00 UTC on June 12, 2021 (16:00 PST on June 11).

Mixing heights on the evening of June 11 were also consistent with the previous day, with a boundary layer height of 735 mb (2,743 meters) during the 00:00 UTC Las Vegas sounding on June 12 (16:00 PST on June 11) (**Figure 43**).

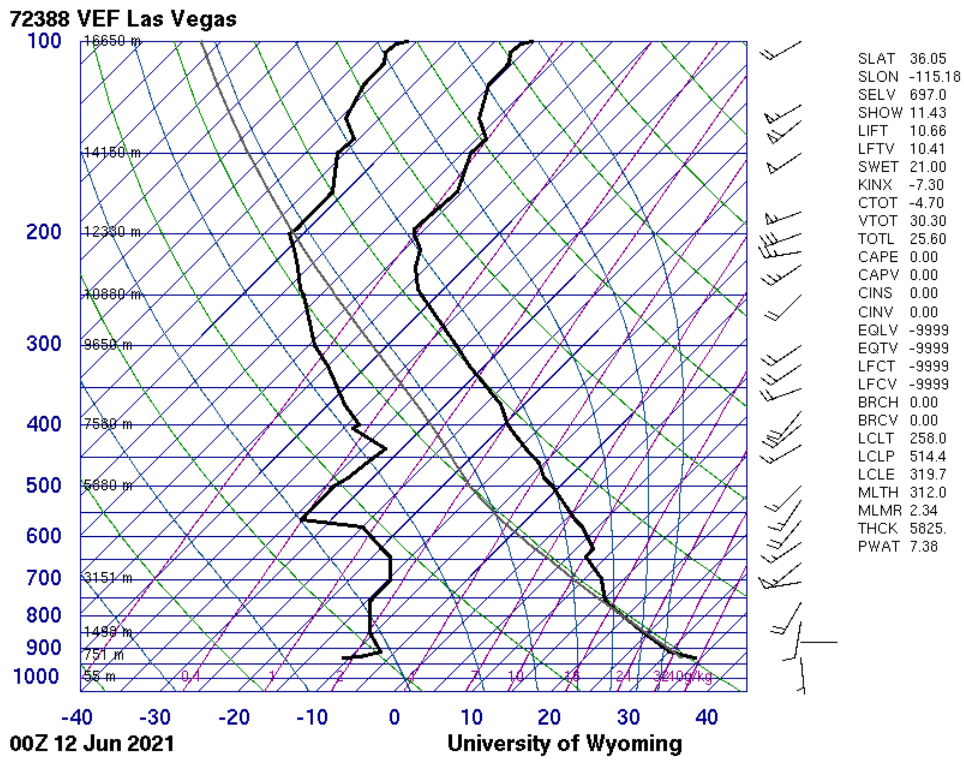

Figure 43. Sounding from Las Vegas, NV, at 00:00 UTC on June 12 (16:00 PST on June 11), 2021.

Again, HRRR back trajectories were computed at 00:00 UTC on June 12 (16:00 PST on June 11) over the previous six hours (**Figure 44**) to determine the potential for continued smoke transport across the Las Vegas region on the afternoon and evening of June 11. Trajectories at the top of the boundary layer continued to support smoke transport from the Sandy Valley Fire. In addition, the short trajectories within the Las Vegas Metro area were computed at 10 meters, indicating light winds and limited dispersion near the surface during the afternoon and early evening of June 11.

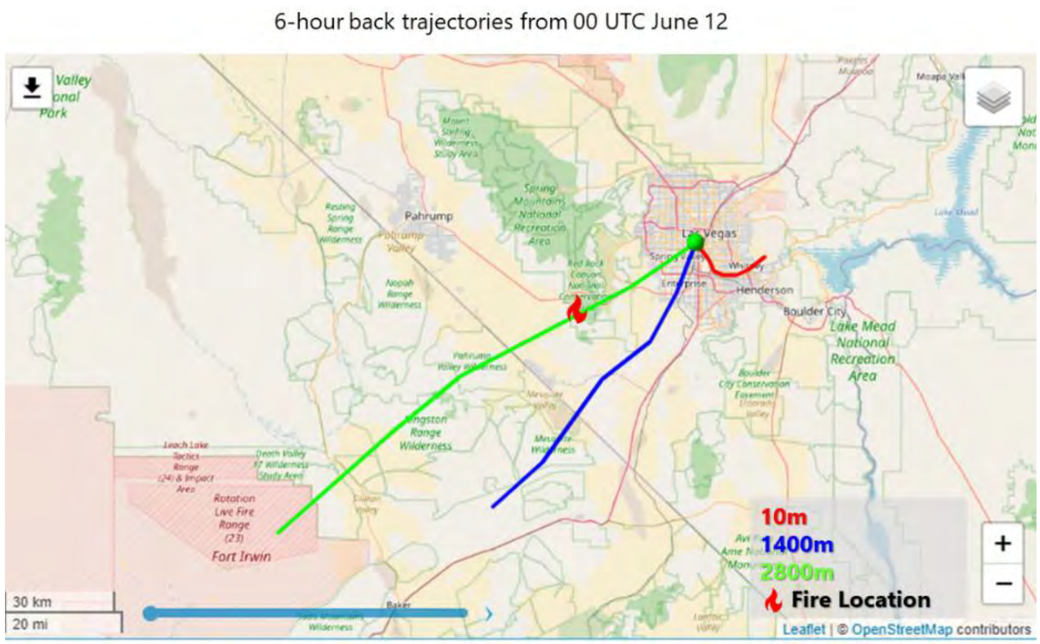

Figure 44. HYSPLIT back trajectories from 10, 1,400, and 2,800 meters using HRRR 3-km meteorological data and initiated at 00:00 UTC on June 12 back through 18:00 UTC on June 11 (16:00 PST on June 11 back through 10:00 PST on June 11).

The ridge of high pressure at 700 mb east of Las Vegas amplified on June 12, leading to a slight increase in the southerly wind component over Las Vegas. This pushed HRRR boundary layer back trajectories south of the Sandy Valley Fire. However, light winds continued to limit dispersion at the surface through June 12, allowing smoke to linger in the area. Table 9 summarizes the average surface wind speeds and directions at the meteorological stations across Las Vegas from June 10-12.

Table 9. Wind speed and direction from meteorological sites across the Las Vegas Valley for the exclusion days.

Station Name (ID)	Day	Average Wind Speed (kts)	Average Wind Direction (deg)
Las Vegas – Harry Reid Intl. (LAS)	06-10-21	7.6	225
Henderson (HND)	06-10-21	9.7	215
NORTH LAS VEGAS (VGT)	06-10-21	10.9	279
Las Vegas – Harry Reid Intl. (LAS)	06-11-21	3.5	103
Henderson (HND)	06-11-21	5.4	166
NORTH LAS VEGAS (VGT)	06-11-21	5.3	348
Las Vegas – Harry Reid Intl. (LAS)	06-12-21	5.7	164
Henderson (HND)	06-12-21	4.6	15
NORTH LAS VEGAS (VGT)	06-12-21	3.8	143

As shown in Table 9, moderate westerly to southwesterly winds on June 10 subsided, with average wind speeds between 3-6 knots at all three Automated Surface Observing Systems (ASOS) sites in Las Vegas on June 11 and 12. Figure 45 shows that surface winds speeds from meteorological sites in the Las Vegas region throughout June 11 and 12 also indicated calm-to-light and variable winds limited dispersion each day, which allowed smoke to linger over the area.

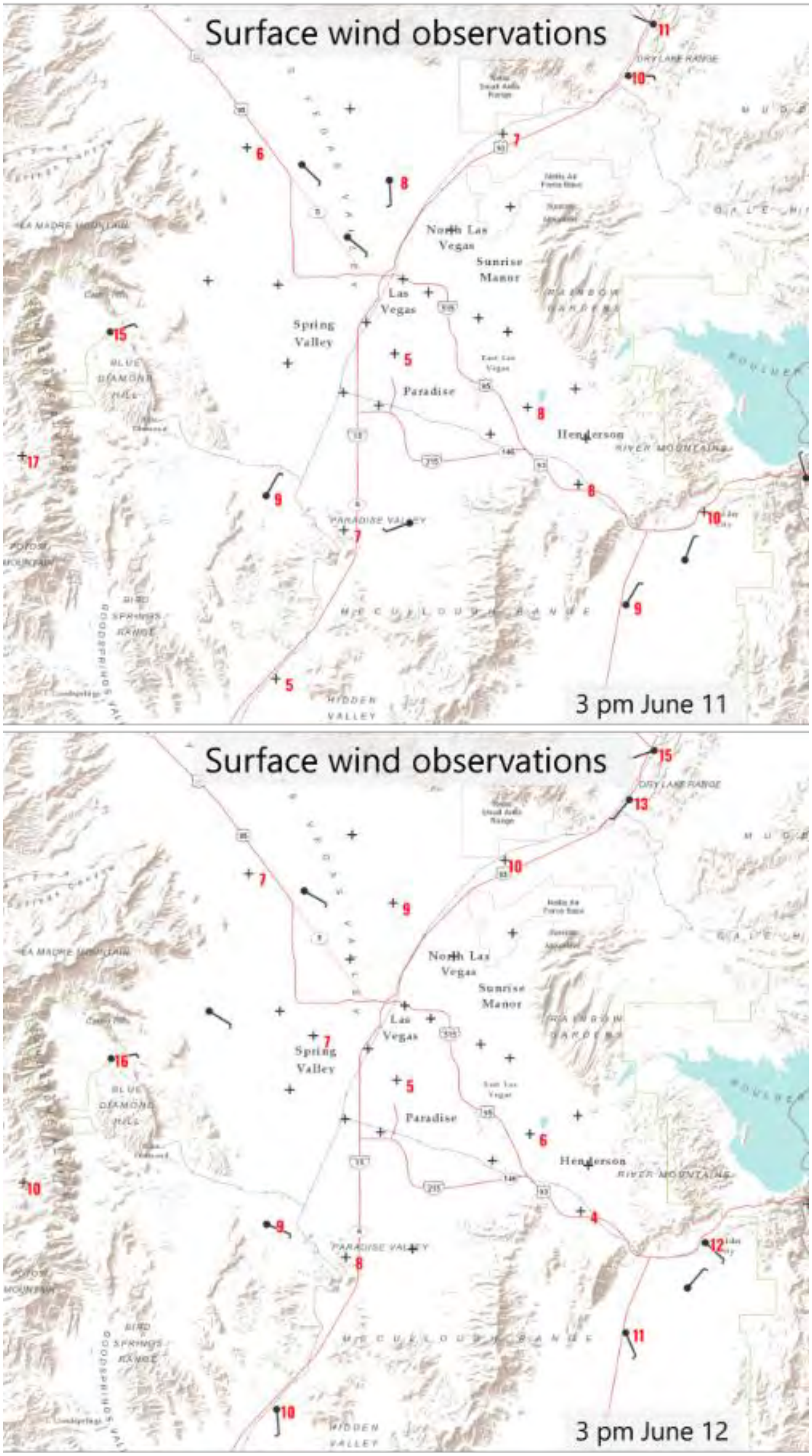

Figure 45. Light and variable surface winds are observed during the afternoons of June 11 and June 12, 2021, in the Las Vegas Valley. Wind speeds are in mph.

4.1.4 Surface Impacts

The smoke plume from the Sandy Valley Fire spread over Las Vegas during the evening of June 10, 2021. Figure 46 through Figure 48 show photos taken from the M Resort in Las Vegas between 18:30 and 19:30 PST, where the smoke plume first becomes visible at 18:30 PST in the north-facing camera (top left pane). Over the next hour, the plume spreads into view of the northeast and northwest facing camera as it expands across the valley. This prominent smoke plume was a news-worthy occurrence reported on by KTNV; their report, "Sandy Valley Fire southwest of Las Vegas grows to 1,500 acres, human-caused", provided videos of the growing smoke plume (https://www.ktnv.com/news/crews-respond-to-fire-southwest-of-las-vegas-near-sandy-valley-road-highway-160).

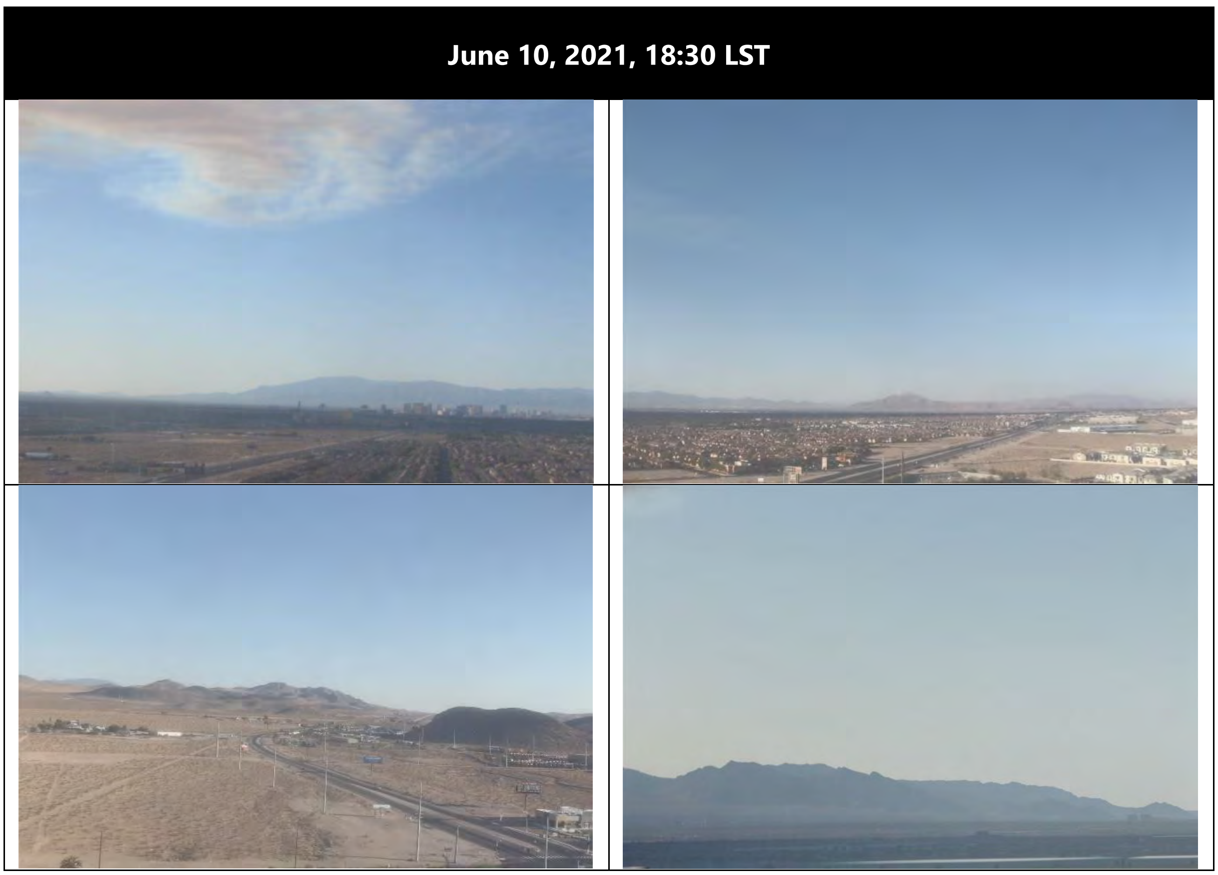

Figure 46. Camera Images showing the north (top left), south (bottom left), northeast (top right), and northwest (bottom right) coordinal directions taken from the M Resort Hotel in Clark County, NV, on June 10, 2021, at 18:30 PST. (Local standard time [LST] are used interchangeably with PST in this document.)

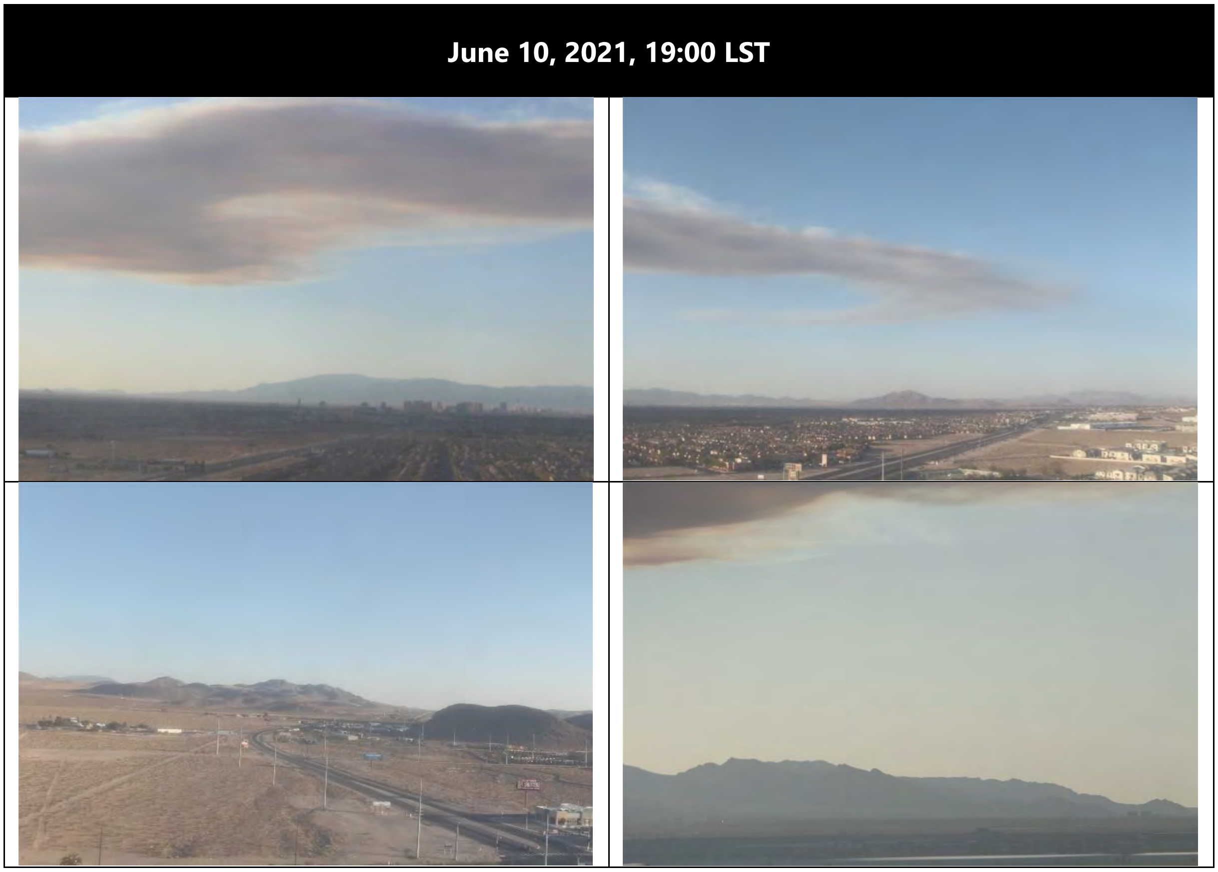

Figure 47. Camera Images showing the north (top left), south (bottom left), northeast (top right), and northwest (bottom right) coordinal directions taken from the M Resort Hotel in Clark County, NV, on June 10, 2021, at 19:00 PST.

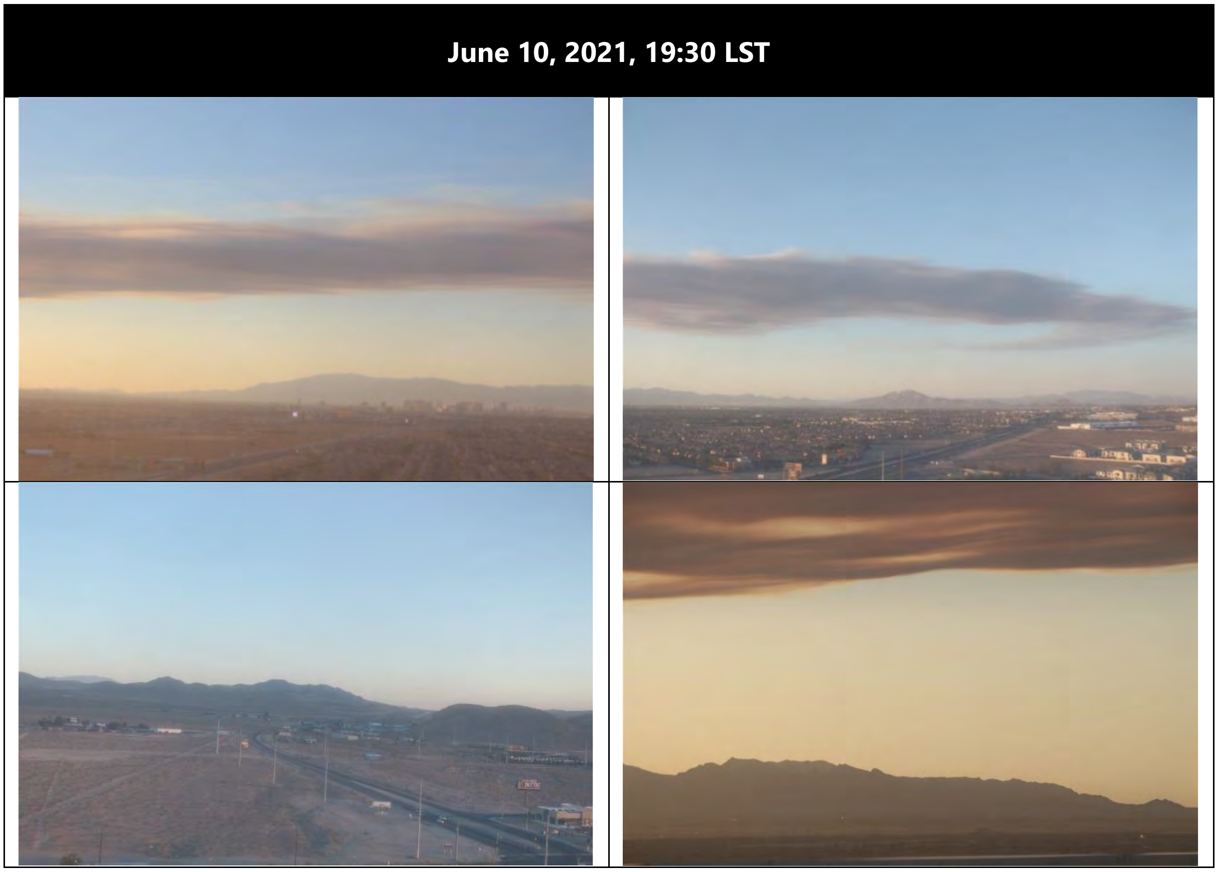

Figure 48. Camera Images showing the north (top left), south (bottom left), northeast (top right), and northwest (bottom right) coordinal directions taken from the M Resort Hotel in Clark County, NV, on June 10, 2021, at 19:30 PST.

$PM_{2.5}$, CO, and NO_2 concentrations were enhanced in Clark County overnight between June 10 and 11 as smoke from the Sandy Valley Fire entered the region and mixed towards the surface, which provides further evidence that wildfire smoke was present as an atypical influence on ozone during the exclusion period. Figure 49(a) shows hourly $PM_{2.5}$ concentrations at the Green Valley site (one of the affected sites) overlaid on the 10th-90th percentile hourly concentrations during ozone season (May to October), calculated using data from 2017-2021. $PM_{2.5}$ concentrations rose sharply to a high peak concentration of 17.3 µg/m^3 at the Green Valley site as smoke moved into the area, reaching concentrations that far exceed the 90th percentile average concentration between 23:00 PST on June 10 and 03:00 PST on June 11.

Figure 49(b) shows hourly CO concentrations at the Green Valley site during the same period, alongside the 5-yr seasonal 10th-90th percentile range of diurnal CO concentrations. The overnight CO concentration did not decrease to an expected overnight low, but instead remained enhanced well above the 90th percentile concentration between 23:00 PST on June 10 and 03:00 PST on June 11, the same time that $PM_{2.5}$ was enhanced.

NO_2 concentrations in Clark County were also enhanced between June 10 and 11, as shown in **Figure 49(c)**. Concentrations exceeded the 90th percentile concentration on the evening of June 11. Data is shown from the Joe Neal site because NO_2 data is not collected at the Green Valley site.

The ratio of $PM_{2.5}$-to-PM_{10} concentrations was also examined for evidence that wildfire smoke entered Clark County. Increases in this ratio are indicative of wildfire smoke. **Figure 49(d)** shows a time series of data collected at the Jean site showing the ratio of $PM_{2.5}$-to-PM_{10} concentrations from June 10 through June 13 compared to the ozone season mean and 5th - 95 percentile range for available data between 2017-2021. The Jean site is upwind of Clark County and along the trajectory route between the Sandy Valley Fire and the Las Vegas Valley, allowing for examining the $PM_{2.5}$-to-PM_{10} ratios in the absence of anthropogenic particulate emissions. During the evening of June 10 and morning of June 11, ratios exceeded the 5-yr hourly average and the 95th percentile, and reached approximately 0.75, which is indicative of wildfire smoke entering the area and in agreement with the HYSPLIT back trajectory (Figure 41) which showed the smoke plume passed through the Jean monitoring station as it entered the valley. These observations provide further evidence that ground-level wildfire smoke entered Clark County on June 10 and 11 containing increased $PM_{2.5}$ concentrations and enhanced $PM_{2.5}$ to PM_{10} ratios immediately prior to the atypical ozone events occurring on June 11 and 12.

Time series data for $PM_{2.5}$, CO, and NO_2, and $PM_{2.5}$-to-PM_{10} ratios at all other affected sites is shown in **Figure 50 through Figure 53.**

The concurrence of increased $PM_{2.5}$, CO, and NO_2 concentrations, the enhanced $PM_{2.5}$-to-PM_{10} ratio in Clark County overnight between June 10 and 11, and the imagery showing a smoke plume over the region, provide strong evidence that surface-level smoke was present in Clark County during the exclusion period. Increased concentrations of $PM_{2.5}$ on June 11 is consistent with transport of more particulate matter during the flaming portion of a quickly spreading fire. By June 12, the fire had been significantly contained, and was more likely to be smoldering (producing more gaseous pollutants than particulate). This is consistent with the increased NO_2 and CO concentrations during the later days of the fire while the $PM_{2.5}$ and $PM_{2.5}$-to-PM_{10} ratios return to near normal. This combined evidence suggests that the Sandy Valley Fire provided an atypical source of ozone and ozone precursors that caused enhanced ozone concentrations on June 11 and 12, 2021.

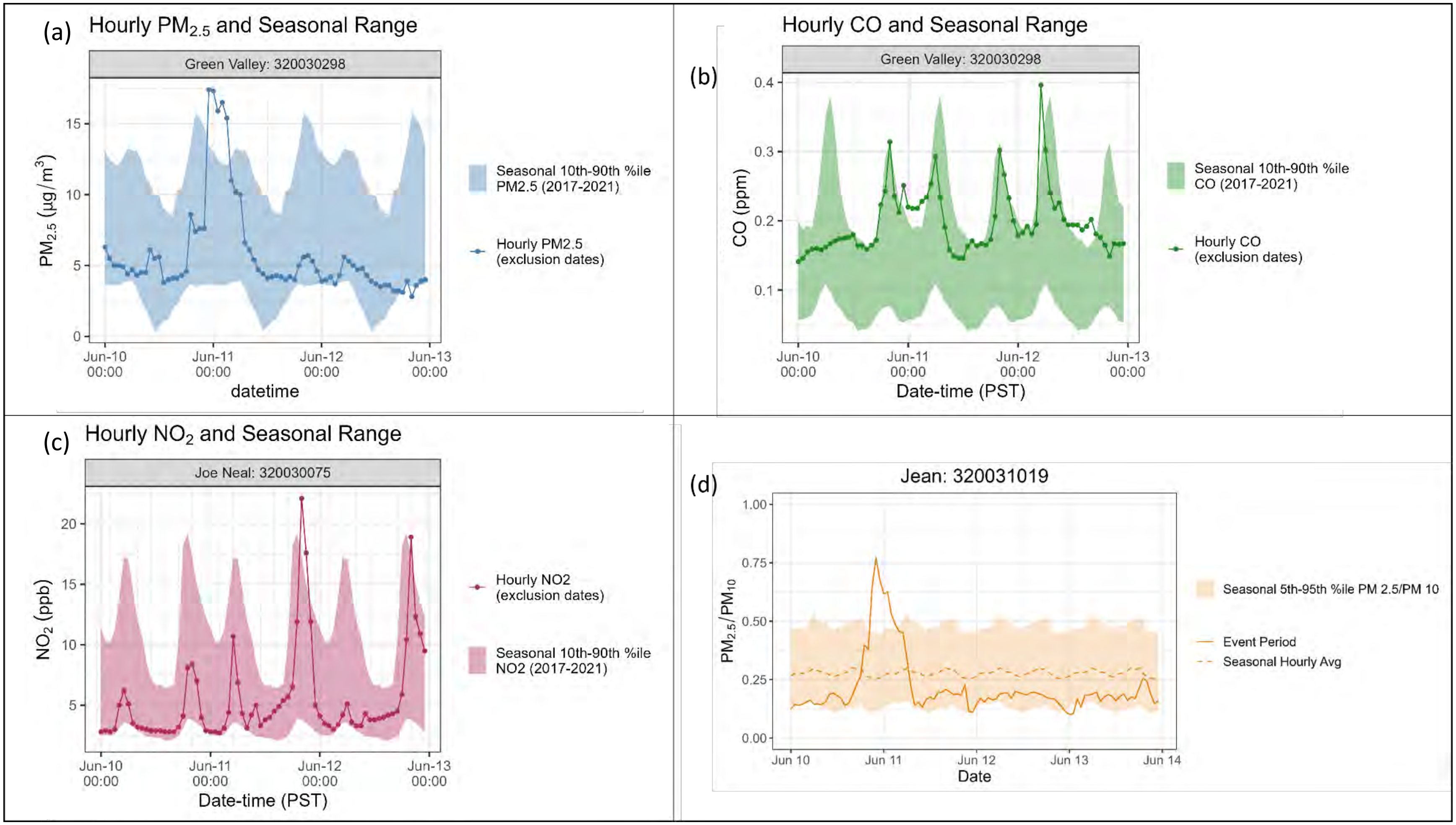

Figure 49. (a) Hourly $PM_{2.5}$ measurements overlaid on the 10th-90th percentile diurnal concentration at the Green Valley site. (b) Hourly CO measurements overlaid on the 10th-90th percentile diurnal concentration at the Green Valley site. (c) Hourly NO_2 measurements overlaid on the 10th-90th percentile diurnal concentration at the Jerome Mack-NCore site. (d) Ratio of $PM_{2.5}/PM_{10}$ concentrations at the Jean site during the June 11 and June 12 event period. The 10th-90th percentile and 5th-95th percentile concentration in each figure is calculated for each site and parameter across the ozone production season (May-October) of 2017-2021.

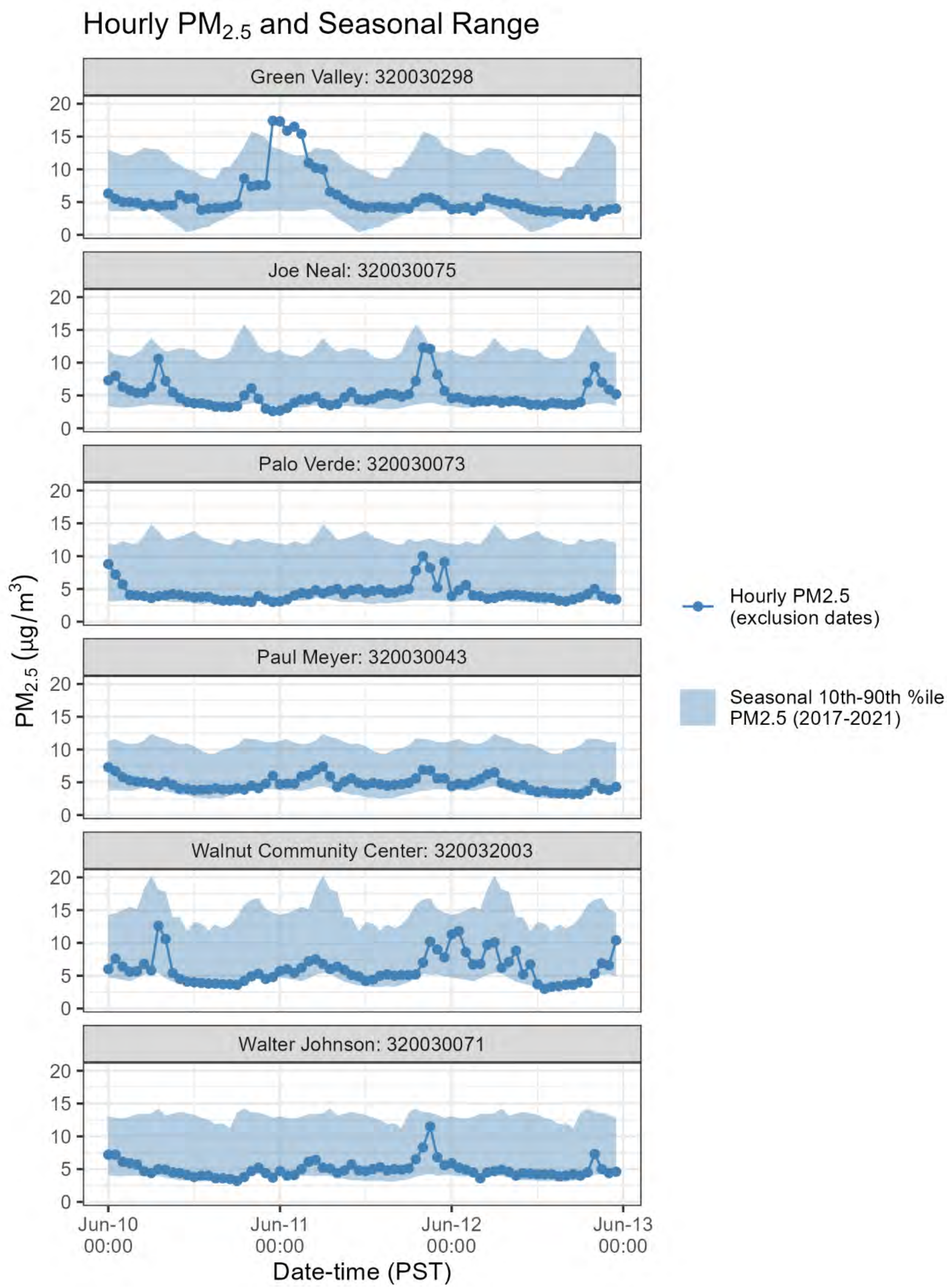

Figure 50. Hourly $PM_{2.5}$ measurements overlaid on the 10th-90th percentile diurnal concentration at all affected sites.

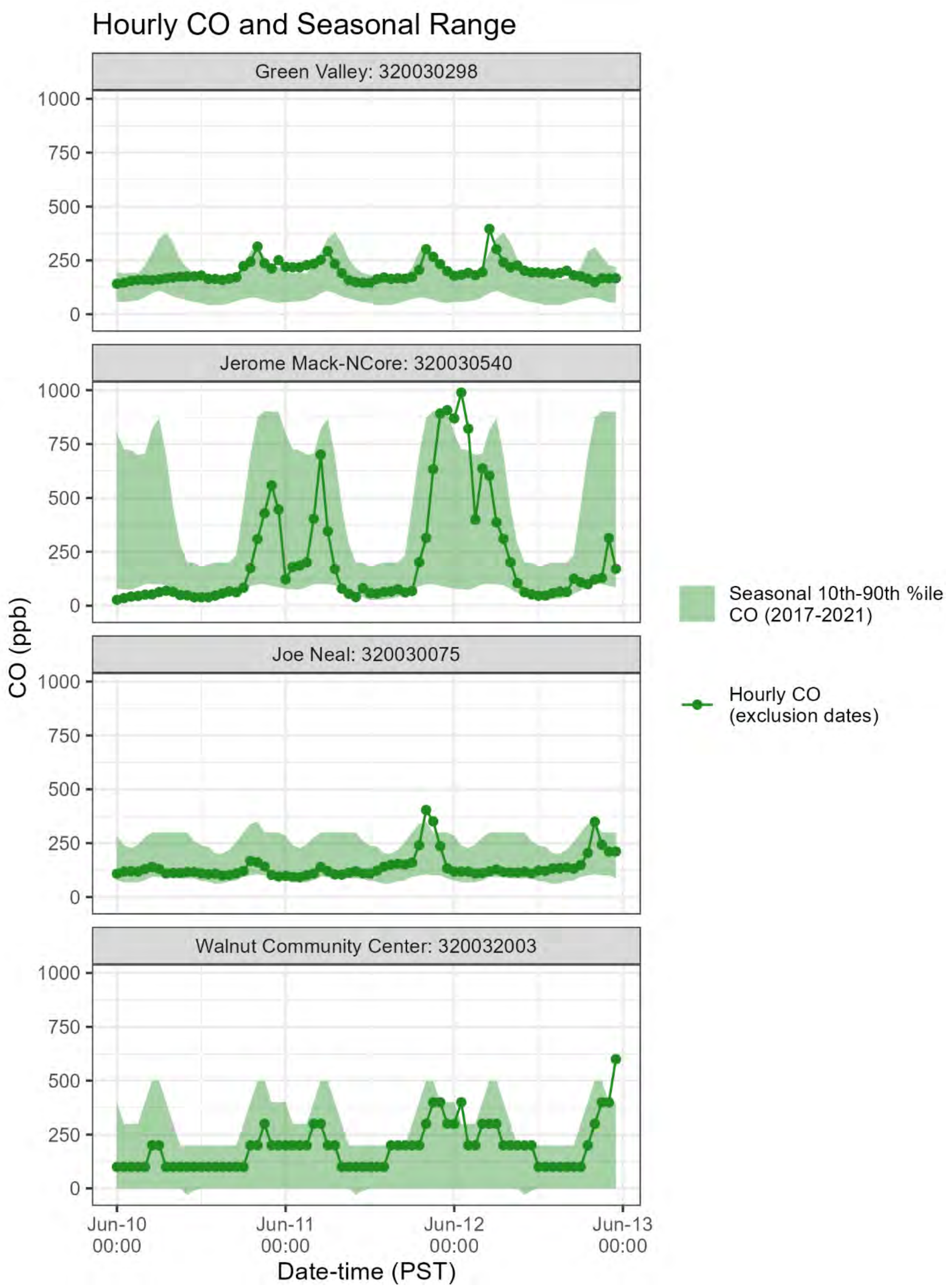

Figure 51. Hourly CO measurements overlaid on the 10th-90th percentile diurnal concentration at all affected sites.

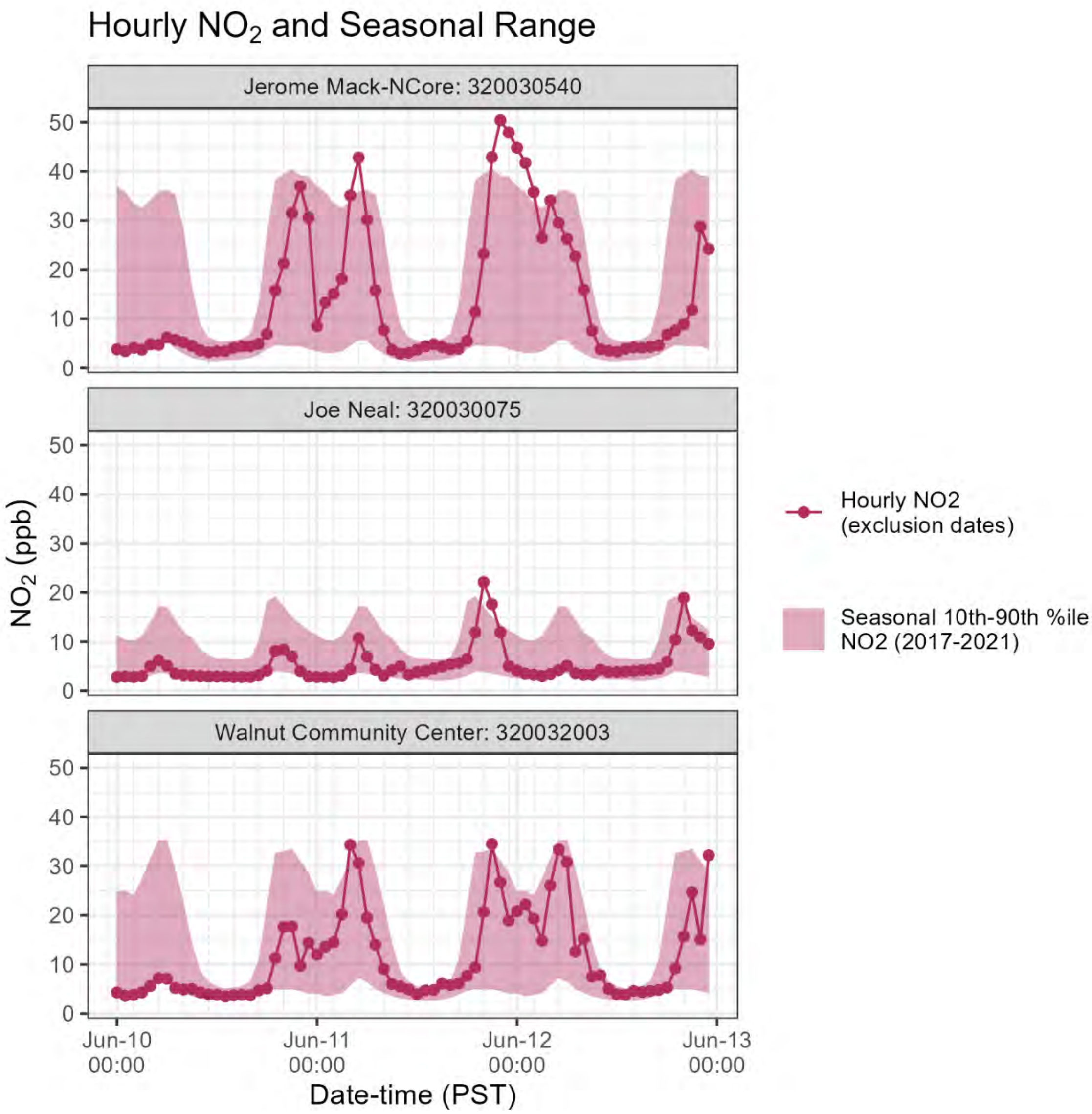

Figure 52. Hourly NO_2 measurements overlaid on the 10th-90th percentile diurnal concentration at all affected sites.

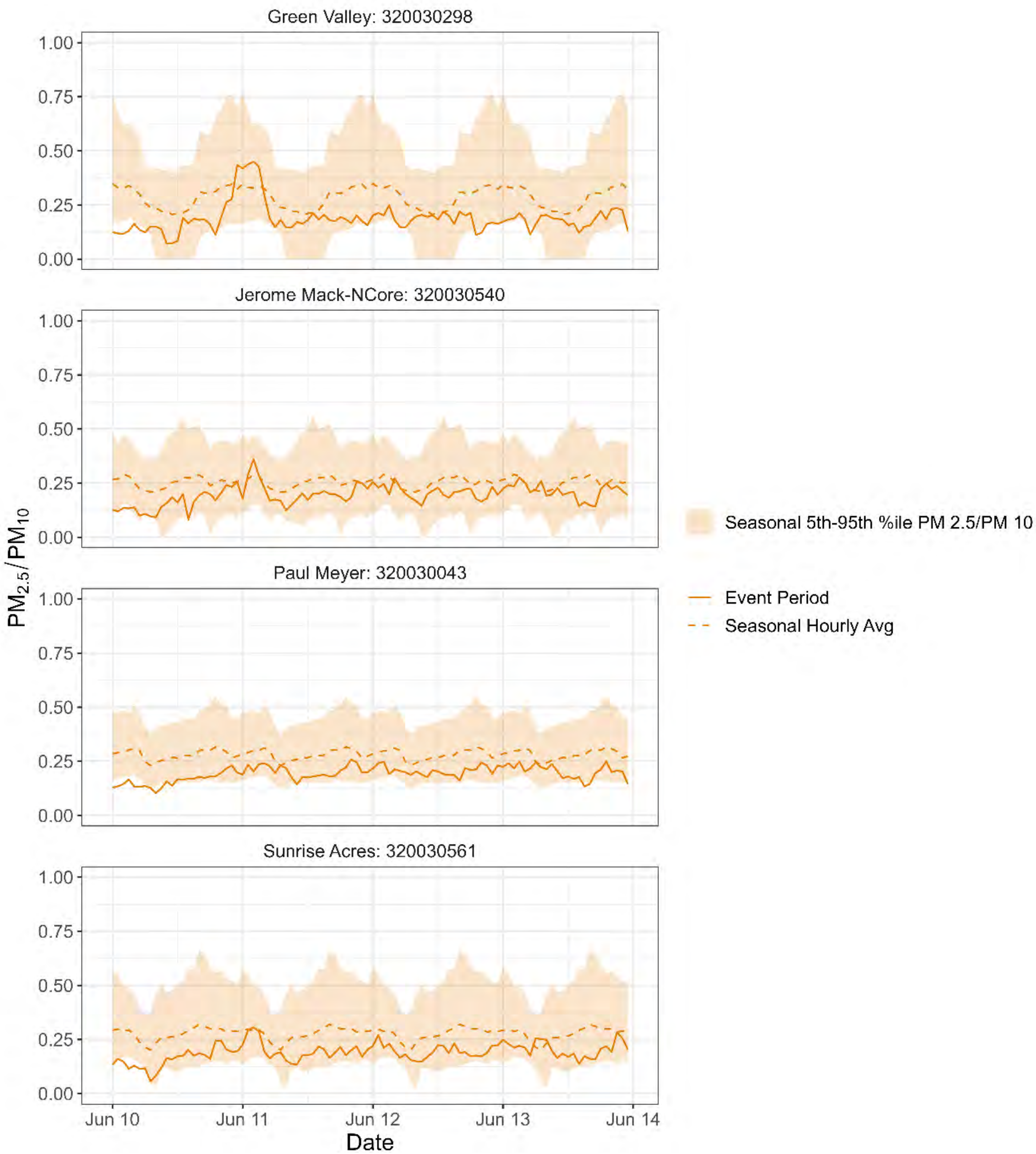

Figure 53. Hourly $PM_{2.5}$-to-PM_{10} measurement ratios overlaid on the 10th-90th percentile diurnal concentration at all affected sites.

4.1.5 Event Statistics

Table 10 summarizes the measurements of ozone, $PM_{2.5}$, CO, and NO_2 concentrations on June 11 and 12, 2021, as well as the percentile rank of the observation compared to the previous five years of ozone season data (May 1-October 31, 2017-2021). Ozone MDA8 measurements ranged from the 93rd to 97th percentile on June 11-12.

24-hr average $PM_{2.5}$ measurements were scattered, ranging from the 15th-75th percentile. As shown in Figure 49(a), peak hourly concentrations are split across the end of June 10 and the beginning of June 11, with lower concentrations (<7 ppb) on either end of the observed spike. As a result, the 24-hr average $PM_{2.5}$ concentrations do not adequately capture the observed hourly anomalies.

CO and NO_2 measurements are not measured at all affected sites and less than five years of data is available for comparison at most sites where it is measured. Data from the Jerome Mack site is thus also included for additional context on enhanced CO and NO_2 observations across the region. In general, CO 1-hr daily maximum measurements in Clark County were somewhat higher than typical ozone season values, ranging from 300-989 ppb, or the 47th-87th percentile for each site. NO_2 1-hr daily maximum observations ranged from 22.1 to 50.4 ppb, or the 70th-96th percentile for each site.

Table 10. Percentile of pollutant measurements on exclusion day compared with most recent five years* (2017-2021). The percentile rank is calculated across the ozone production season (May 1-October 31) of 2017-2021. Data from nearby sites not identified for exclusion are shown in grey italics.

Date	Site Name	Site Code	Ozone		$PM_{2.5}$		CO		NO_2	
			Ozone MDA8 (ppb)	Percent Rank	$PM_{2.5}$ 24-hr Avg ($\mu g/m^3$)	Percent Rank	CO 1-hr Daily Max (ppb)	Percent Rank	NO_2 1-hr Daily Max (ppb)	Percent Rank
6/11/2021	Paul Meyer	320030043	72	96.4	5.4	40.5	--	--	--	--
6/11/2021	Walter Johnson	320030071	72	94.7	5.5	35.8*	--	--	--	--
6/11/2021	Joe Neal	320030075	73	96.6	5.3	38.3*	404	87.4*	22.1	81.7
6/11/2021	Green Valley	320030298	71	96.2	7.4	71.8	302	61.8*	--	--
6/11/2021	Walnut Comm. Center	320032003	72	96.1*	6	24.8*	400	47.7*	34.5	70.6*
6/11/2021	*Jerome Mack-NCore*	*320030540*	--	--	--	--	*907*	*79.6*	*50.4*	*96.8*
6/12/2021	Walter Johnson	320030071	71	93.2	4.5	15.8*	--	--	--	--
6/12/2021	Palo Verde	320030073	71	97.3	3.9	17*	--	--	--	--
6/12/2021	*Jerome Mack-NCore*	*320030540*	--	--	--	--	*989*	*81.8*	*44.8*	*89*

*Sites that have less than five years of data available for a given parameter.

4.2 June 16-17, 2021

4.2.1 Event Summary

The unrepresentative ozone event took place on June 16-17, 2021, and affected five sites in Clark County, Nevada: Palo Verde, Joe Neal, Paul Meyer, Walter Johnson, and Mountains Edge Park. The MDA8 concentrations at the effected sites ranged from 71-75 ppb: 74 ppb at Palo Verde, 72 ppb at Joe Neal, and 71 ppb at Paul Meyer and Walter Johnson on June 16, and 75 ppb at Mountains Edge Park and 72 ppb at Paul Meyer on June 17. Time series graphs showing hourly ozone concentrations that exceeded the ozone season means and 10th-90th percentiles (calculated using May 1-October 31, 2017-2021) at each site are shown in Figure 54.

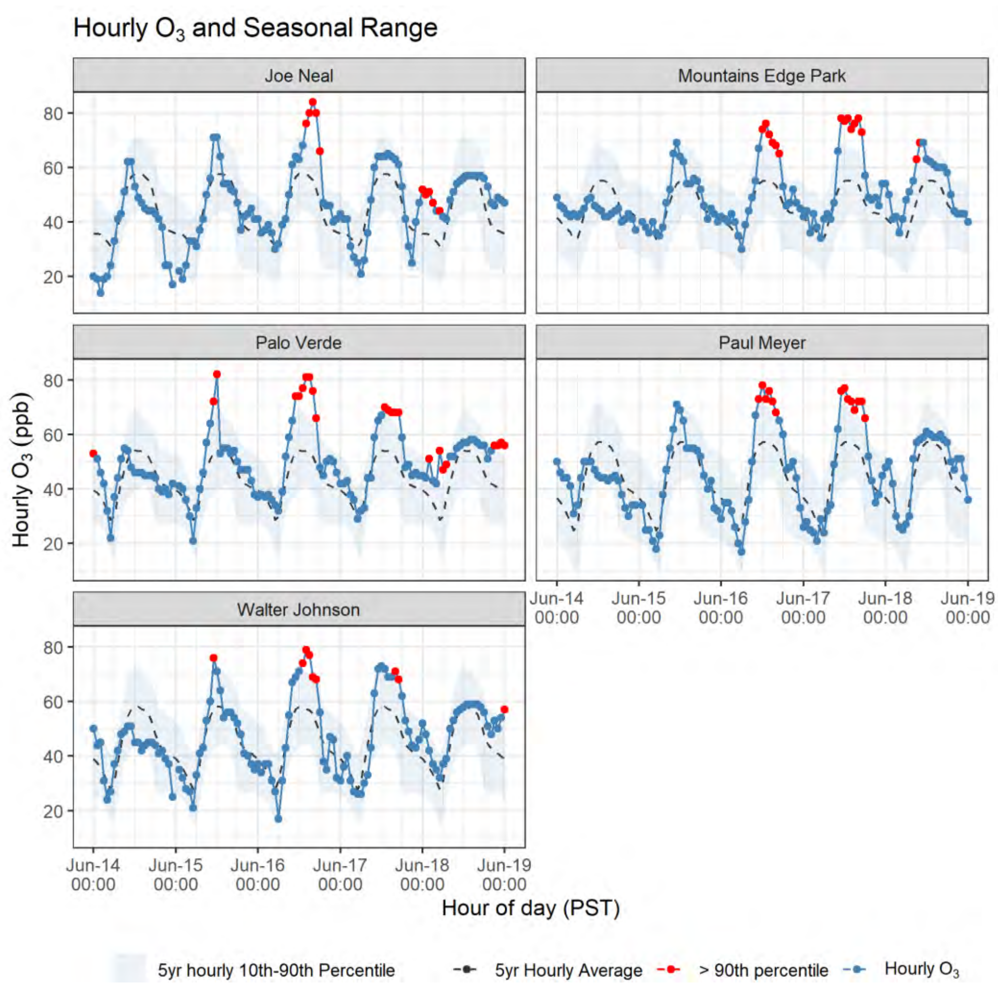

Figure 54. Hourly ozone concentrations (ppb) compared to 5-yr* ozone season (May 1-October 31, 2017-2021) hourly means and 10-90th percentiles. *Note: data from the Mountains Edge Park site are only available for June 1-October 31, 2021.

On June 16, hourly ozone measurements rose sharply above (>10%) the mean beginning as early as 08:00 PST and exceeded the 90th percentile between 11:00-18:00 PST. On June 17, hourly ozone measurements began rising sharply above the mean at 10:00 PST and surpassed 90th percentile between 11:00-17:00 PST.

Four major wildfires with significant emissions – the Johnson Fire event in New Mexico and the Telegraph, Pinnacle, and Slate Fires in Arizona – were identified to be the major contributors to the regional wildfire smoke that precipitated the event. Evidence indicating this is an unrepresentative event for assessing base and future ozone design value assessments includes (1) HYSPLIT dispersion modeling showing accumulation of smoke in Clark County, (2) the presence of visible smoke in camera images, and (3) $PM_{2.5}$ concentrations above the 5-yr 90th percentile. Enhanced CO and NO_2 concentrations as well as $PM_{2.5}$-to-PM_{10} ratios provide additional support for the influence of wildfire smoke during this time period.

4.2.2 Identification of Wildfires

Numerous wildfires were active during the June 16-17, 2021, exclusion days and contributed to regional smoke. As mentioned above, four major wildfires with significant emissions that contributed to the regional smoke were identified: the Johnson Fire event in New Mexico, and the Telegraph, Pinnacle and Slate Fires in Arizona (**Figure 55**). Regional smoke was present in mid-June 2021 throughout the southwest U.S., and this was verified for the days of June 14-17 through visualization of smoke and wildfire detection geodata provided by the NOAA HMS (**Figure 56**). **Table 11** presents the state location, total acres within the fire perimeter, and the start and containment dates for each fire based on data from the WFIGS Current Interagency Fire Perimeters.[6]

[6] McClure et al. (2023) Consistent, high-accuracy mapping of daily and sub-daily wildfire growth with satellite observations. International Journal of Wildland Fire 32, 694-708. Available at https://www.publish.csiro.au/wf/ExportCitation/WF22048.

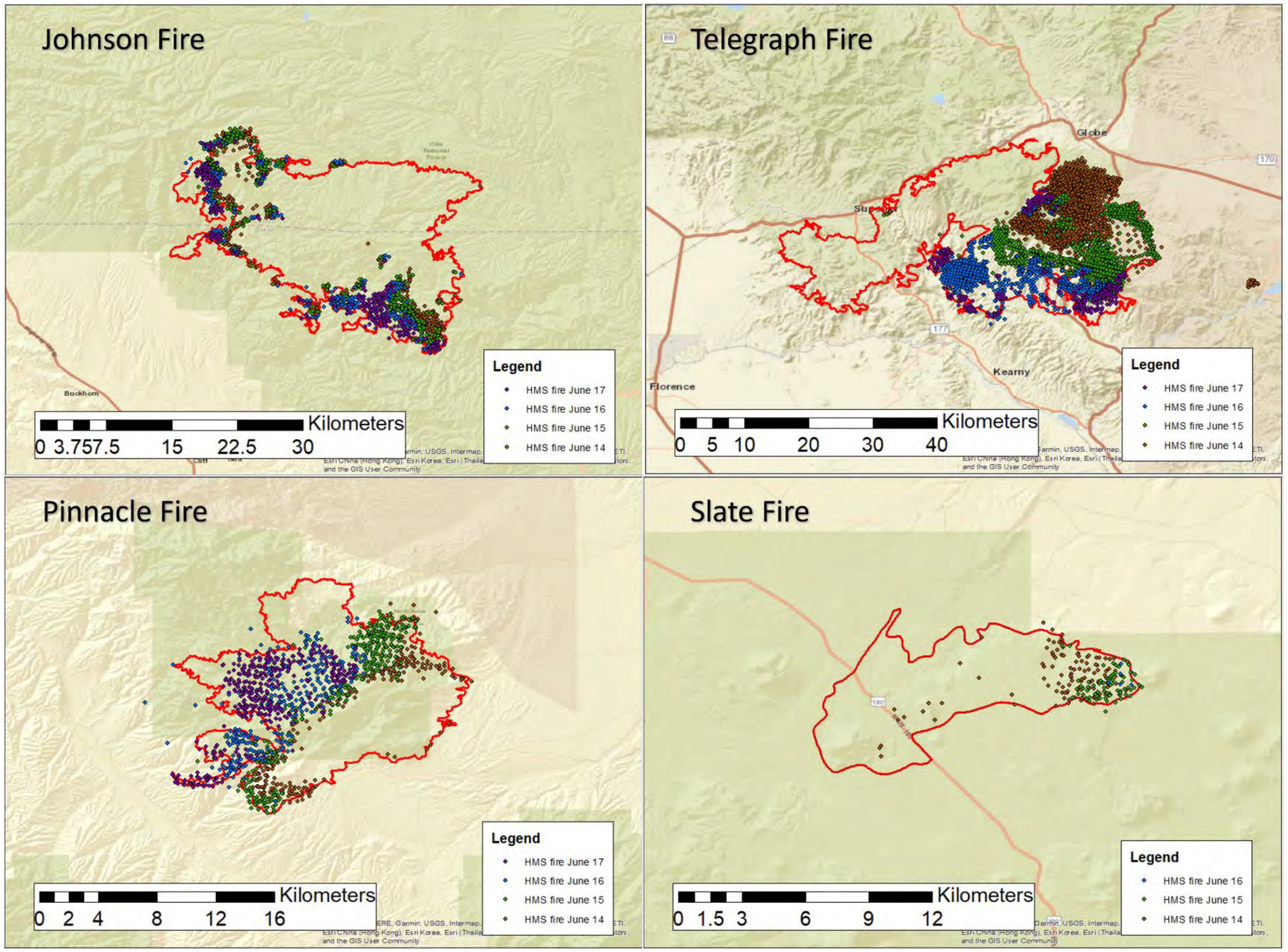

Figure 55. Full fire perimeters (red) and HMS fire detections for the Johnson, Telegraph, Pinnacle, and Slate Fires for June 14-17, 2021.

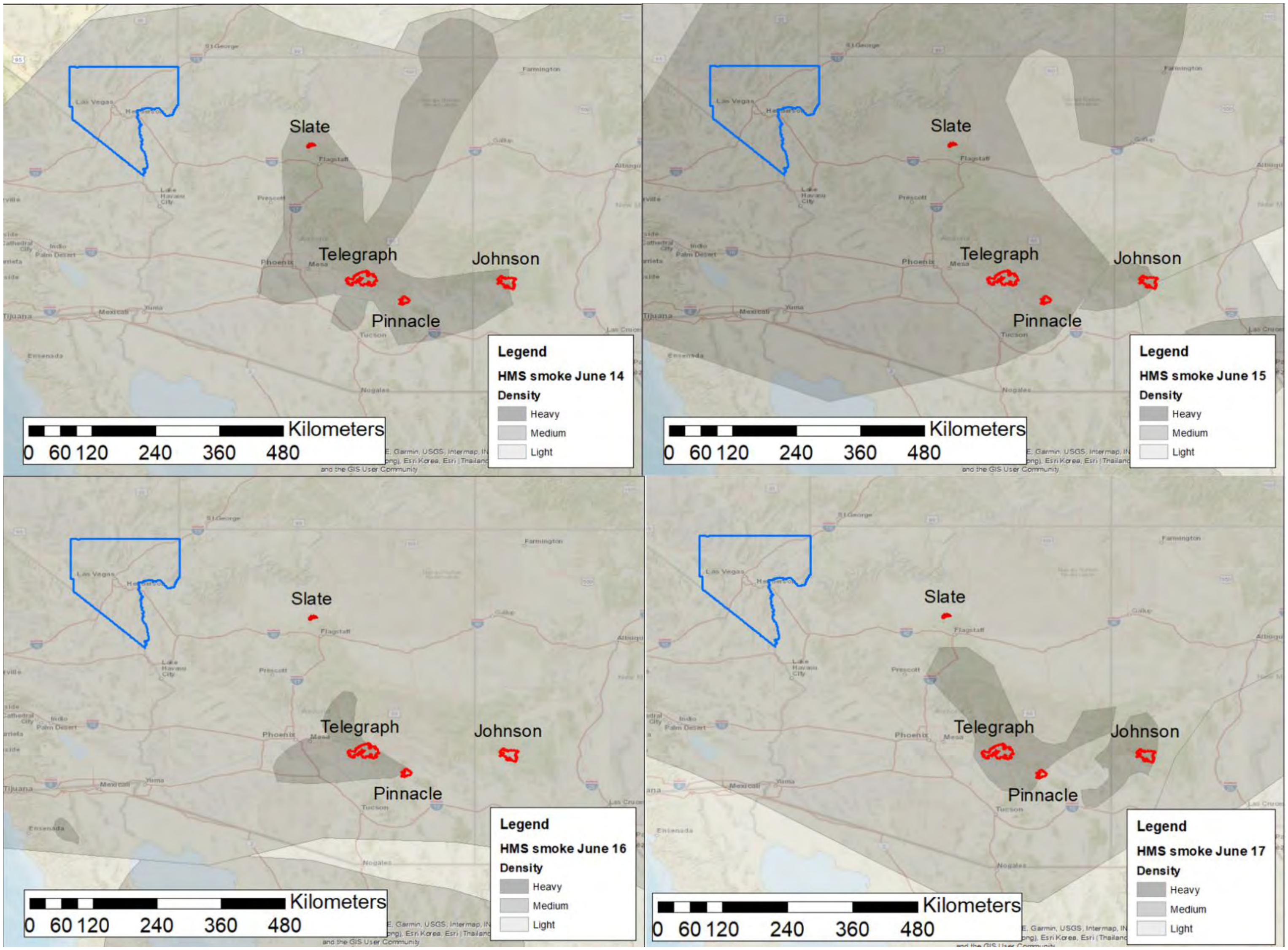

Figure 56. HMS smoke boundaries for June 14-17, 2021, are included with qualitative smoke density. Fire perimeters from the major fires contributing to the exclusion date are shown in red and the Clark County, NV, boundary is shown in blue.

Table 11. Wildfires affecting Clark County on the exclusion days. The fire name, state location, total acreage, acres burned on or before the exclusion days, and the start and containment dates are included.

Wildfire Name	State	Total Acres	Acres Burned On or Before Exclusion Days	Start Date	Containment Date
Johnson	New Mexico	94,732	73,069 (June 15)[7]	May 20	July 22
Telegraph	Arizona	179,678	171,242 (June 17)[8]	June 4	July 3
Pinnacle	Arizona	34,394	17,453 (June 17)[9]	June 10	July 16
Slate	Arizona	11,435	11,435 (June 17)[8]	June 7	July 6

4.2.3 Dispersion Modeling and Regional Analysis

HYSPLIT dispersion modelling was performed for the June 16-18, 2021, period. Dispersion runs were initiated at 00:00 PST from the four identified active fires impacting the exclusion date. Global Data Assimilation System (GDAS) data at 1.0° horizontal resolution was used for meteorological input. Output from the dispersion modeling was integrated over a 48-hr period, from June 16 at 00:00 PST through June 18 at 00:00 PST. This time period was chosen to correspond with the initial increase of observed $PM_{2.5}$ concentrations in Clark County. The accumulation of smoke in the 0-100 m vertical layer for the 24-hr period is shown in Figure 57.

The HYSPLIT dispersion modeling shows that smoke from multiple fires mixed to produce a dense layer of smoke that blanketed the Southwestern U.S. region, including Clark County, NV. The modeling results are consistent with the HMS smoke plume data (shown in gray in Figure 57); HMS is an independent smoke identification database. The results of the dispersion modeling show that smoke from multiple fires reached Clark County on June 16-17, 2021, and the smoke was present in the lower mixed layer of the atmosphere, impacting surface conditions.

[7] https://nmfireinfo.com/2021/06/15/gila-nf-johnson-fire-update-for-june-15-2021/
[8] https://www.azcentral.com/story/news/local/arizona-wildfires/2021/06/17/telegraph-mescal-wildfires-evacuations-el-capitan-dripping-springs-wind-spirit-hagen-ranch/7729359002/
[9] https://www.azcentral.com/story/news/local/arizona-wildfires/2021/06/17/winchester-backbone-pinnacle-slate-cornville-wildfires-burn-arizona/7730847002/

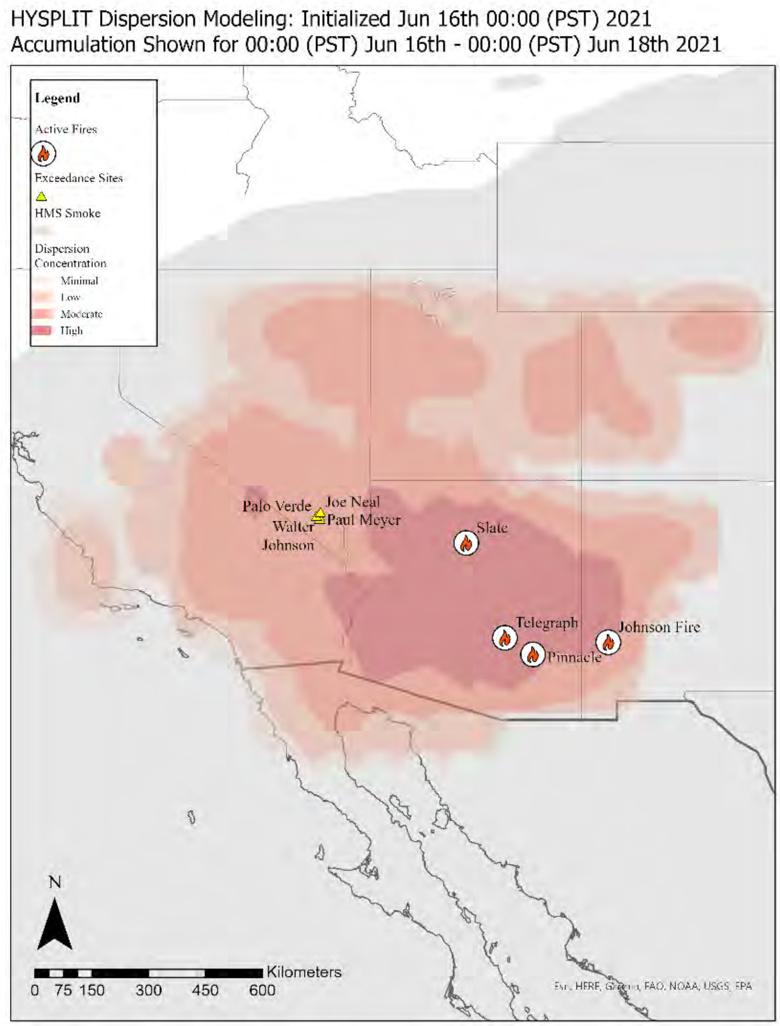

Figure 57. HYSPLIT dispersion modeling for the large fires (labeled as "Active Fires") in Arizona and New Mexico. GDAS 1.0° meteorological data was used, and dispersion was initiated on June 6, 2021, at 00:00 PST to model the regional smoke observed in satellite and HMS products. HMS smoke is shown in gray and qualitative concentrations of particulate matter are shown in shades of red. Accumulation of particulate matter is shown in the 0-100 m vertical layer for 00:00 PST on June 16 through 00:00 PST on June 18, 2021.

Clockwise air flow around upper-level high pressure near the Four Corners transported smoke from fires in Arizona into Clark County, NV (Figure 58). The vertical atmospheric profile for June 16, 2021 (Figure 59), indicates a deep planetary boundary layer of approximately 19,000 feet (5,800 meters) over Las Vegas. Smoke from fires in Arizona originated at an elevation of 7,000 feet (2,100 meters) and became entrained in a clockwise airflow pattern at 700 mb (approximately 10,000 feet) near the Four Corners. This flow pattern is consistent with the dispersion modeling results.

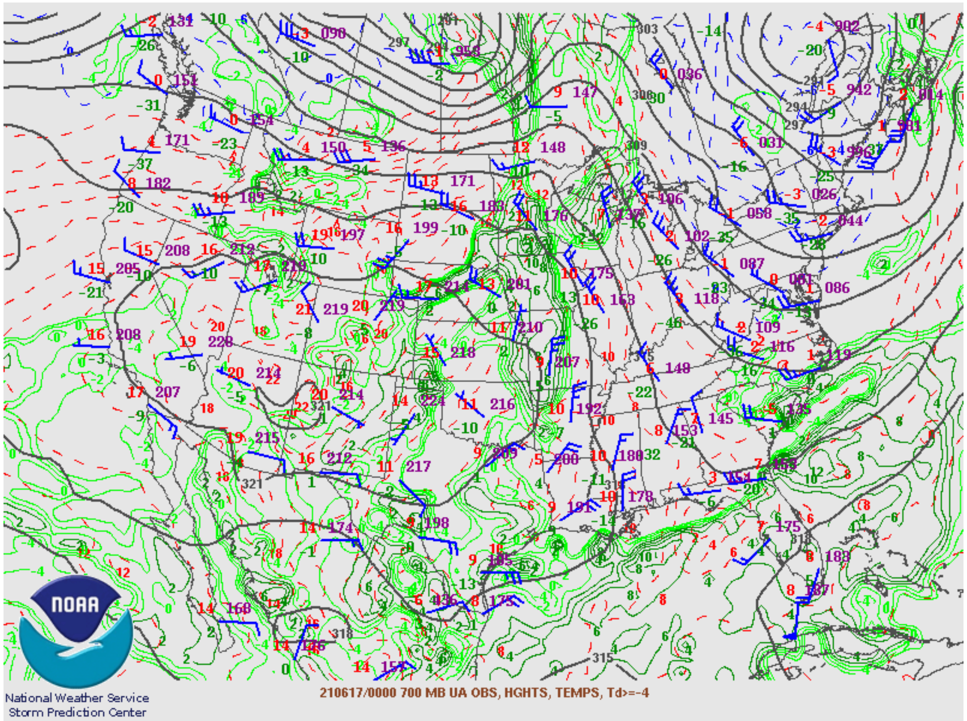

Figure 58. Map of 700-mb (approx. 10,000 feet ASL) air flow. Map valid at 00:00 UTC on June 17, 2021 (16:00 PST on June 16, 2021).

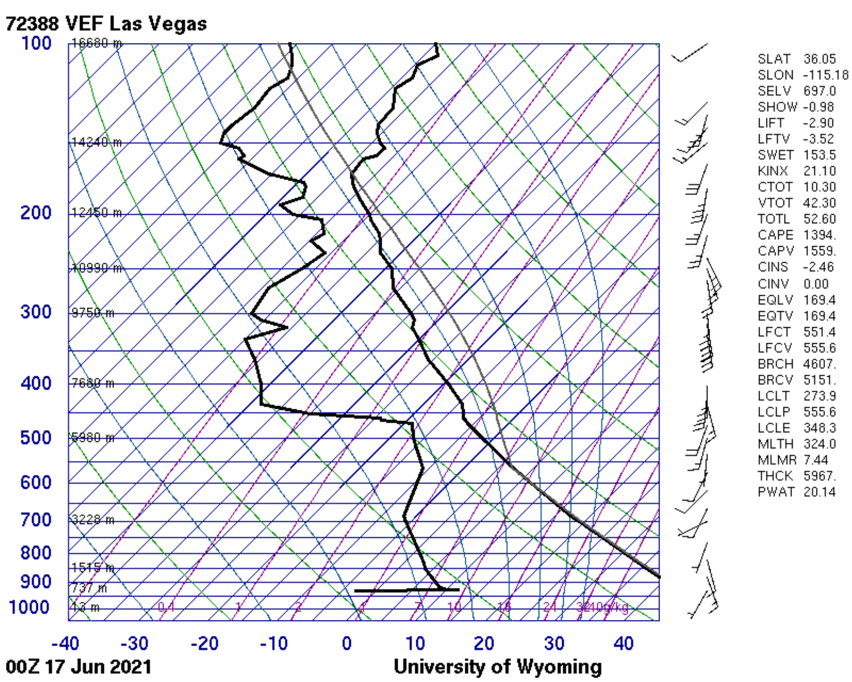

Figure 59 Sounding from Las Vegas, Nevada, at 00:00 UTC on June 17 (16:00 PST on June 16), 2021, where x-axis shows temperature (°C) and y-axis shows pressure (mb). Retrieved from https://weather.uwyo.edu/upperair/sounding.html.

4.2.4 Surface Impacts

The presence of wildfire smoke during the exclusion dates is evident by comparing the visibility conditions on the morning of June 15 (**Figure 60**) to the conditions on the exclusion dates of June 16-17 (**Figure 61 and Figure 62**). Local and regional smoke from the fires identified in Section 4.2.2 is visible in Clark County on both June 16 and 17 at 09:00 PST, when ozone photochemical production typically starts to accelerate. The presence of local and regional smoke had an atypical influence on ozone and ozone precursors in the Clark County area and caused higher than normal ozone concentrations on the exclusion date. Ground observations from KLAS local news, shown in Table 12, confirm that smoke from the Arizona wildfires contributed to haze reported in the remarks section of the news report.

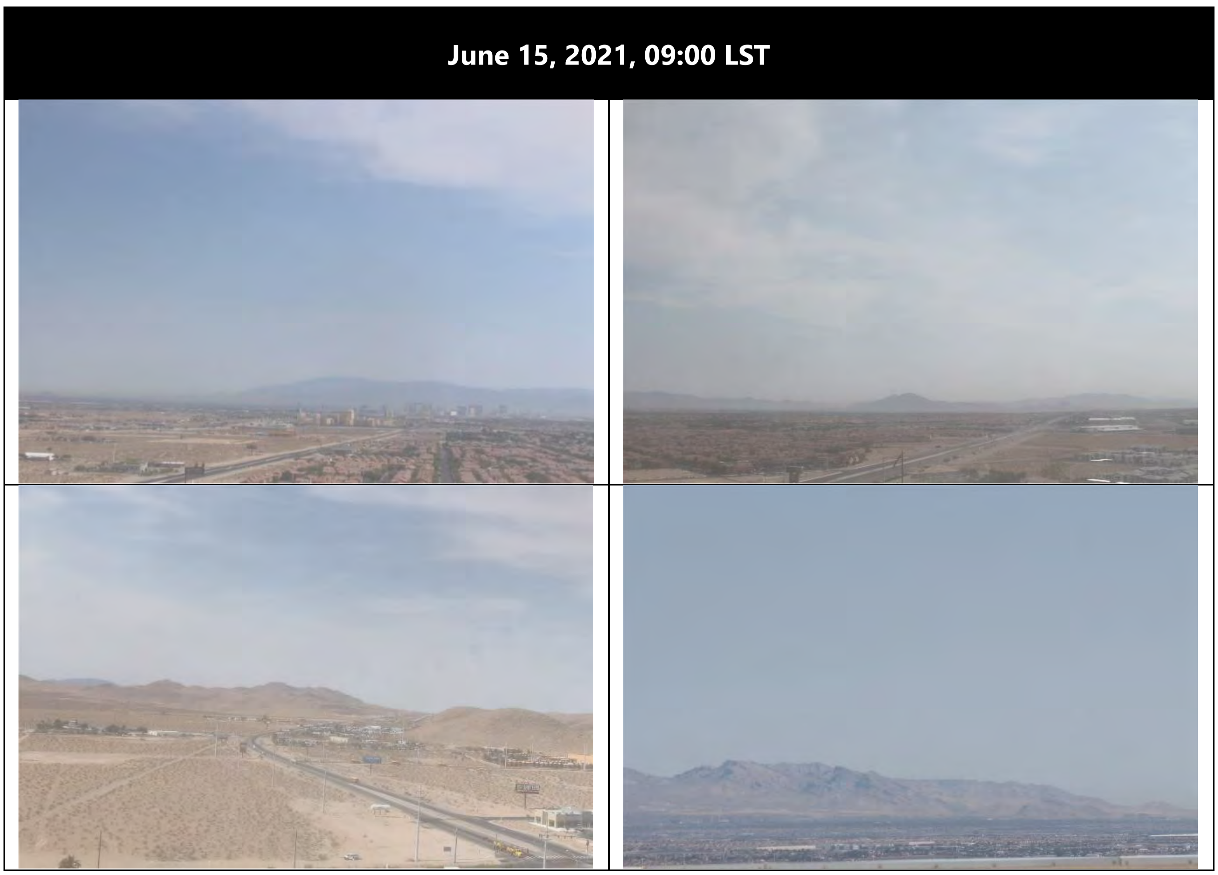

Figure 60. Camera images showing the north (top left), south (bottom left), northeast (top right), and northwest (bottom right) coordinal directions, taken from the M Resort Hotel in Clark County, NV, on June 15, 2021, at 09:00 LST.

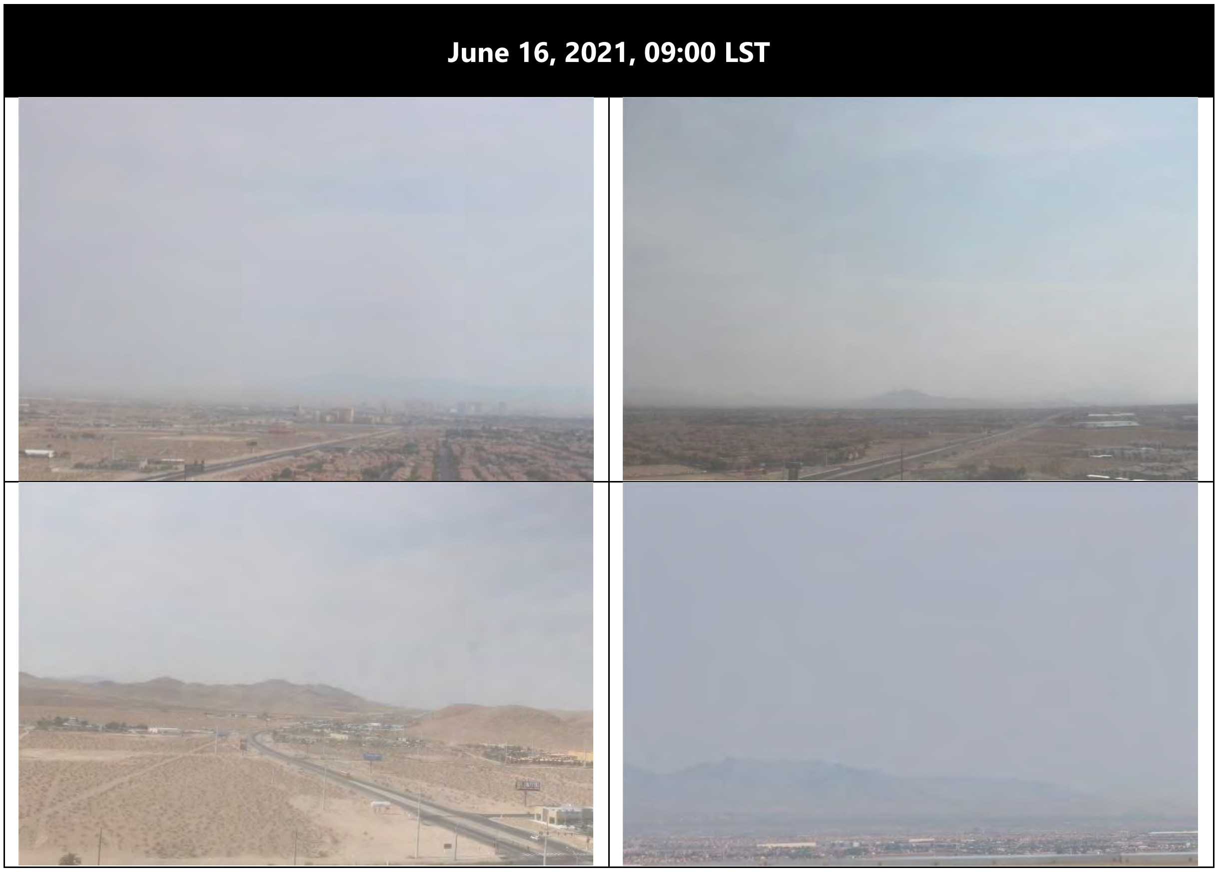

Figure 61. Camera images showing the north (top left), south (bottom left), northeast (top right), and northwest (bottom right) coordinal directions, taken from the M Resort Hotel in Clark County, NV, on June 16, 2021, at 09:00 LST.

June 17, 2021, 09:00 LST

Figure 62. Camera images showing the north (top left), south (bottom left), northeast (top right), and northwest (bottom right) coordinal directions, taken from the M Resort Hotel in Clark County, NV, on June 17, 2021, at 09:00 LST.

Table 12. Hourly ASOS Aviation Routine Weather Report (METAR) reports from KLAS local news on June 16 and 17, 2021 (June 17 and 18, 2021, in UTC). Smoke from Arizona wildfires contributed to periodic haze which was reported in the remarks section of the news report. VRB indicated variable wind speeds.

Time on June 17 and 18 (UTC)	Time on June 16 and 17 (PST)	Wind Direction / Speed	Sky Conditions
00:56	16:56	120 / 05 KT	HAZY
01:56	17:56	110 / 04 KT	HAZY
02:56	18:56	160 / 04 KT	HAZY
21:56	13:56	070 / 12 KT	HAZY
22:56	14:56	330 / 04 KT	HAZY
23:56	15:56	360 / 06 KT	HAZY
00:56	16:56	VRB / 03 KT	HAZY
01:56	17:56	060 / 03 KT	HAZY
02:56	18:56	260 / 05 KT	HAZY
03:56	19:56	220 / 03 KT	HAZY

$PM_{2.5}$, CO, and NO_2 concentrations were enhanced in Clark County during the exclusion period, providing further evidence that wildfire smoke was present in the region as an atypical influence on ozone concentrations. Figure 63 shows hourly $PM_{2.5}$ concentrations for the two-week period surrounding the exclusion dates overlaid on the 10th-90th percentile hourly concentrations during ozone season (May to October), calculated using available data from 2017-2021. $PM_{2.5}$ concentrations peaked between June 15 and 16 as wildfire smoke moved into the region. $PM_{2.5}$ concentrations remained enhanced throughout the exclusion dates. $PM_{2.5}$ at all event-affected sites exceeded the 90th percentile average concentrations on June 16 and 17, 2021.

Figure 64 shows daily maximum 1-hr CO concentrations for the period surrounding the exclusion dates and the 5-yr 10th-90th percentile range of daily maximum 1-hr CO concentrations for the month of June. Between June 16 and 17, all CO measurement sites exceeded the 90th percentile daily maximum 1-hr CO concentration. Note that some sites also show noticeable spikes in CO concentrations in the days prior to the exclusion dates, which are likely due to the local Sandy Valley wildfire on June 11-12 (see Ozone TSD – June 11-12, 2021).

Further evidence that wildfire smoke was present in the area can be seen in the comparison of NO_2 concentrations during the exclusion dates to the expected seasonal range. Figure 65 shows hourly NO_2 concentrations during the exclusion dates overlaid with the 10th-90th percentile hourly concentrations during ozone season (May to October), calculated using data from 2017-2021. Data is shown from the Joe Neal site, which was the only site with elevated ozone during the exclusion dates that also measures NO_2 concentrations. NO_2 concentrations in Clark County were elevated above the 90th percentile concentrations during the exclusion period, reaching a peak during the morning of June 17.

The ratio of $PM_{2.5}$-to-PM_{10} concentrations was also examined to determine if wildfire smoke entered Clark County on or before the exclusion dates. Increases in this ratio are indicative of wildfire smoke. Figure 66 and Figure 67 show a time series graph of the $PM_{2.5}$-to-PM_{10} ratio from June 15 through June 18 at all affected sites, compared to the ozone season mean and 5th-95th percentile range for available data between 2017-2021. The $PM_{2.5}$-to-PM_{10} ratios at all affected sites (Figure 66) are generally above the 5-yr seasonal hourly average during the day on June 16 and 17. Ratios exceeded the 95th percentile and increased above 0.5 in the late morning on June 16, indicating that $PM_{2.5}$ concentrations contributed the majority of total $PM_{2.5}$ and PM_{10} during these hours. A similar pattern is present in some non-affected sites (e.g., Garrett Jr. High, Figure 67). These observations provide evidence that wildfire smoke containing increased levels of $PM_{2.5}$ enhanced the $PM_{2.5}$-to-PM_{10} ratios in Clark County on June 16 and June 17, immediately prior to and during the atypical ozone events that occurred on June 16 and 17.

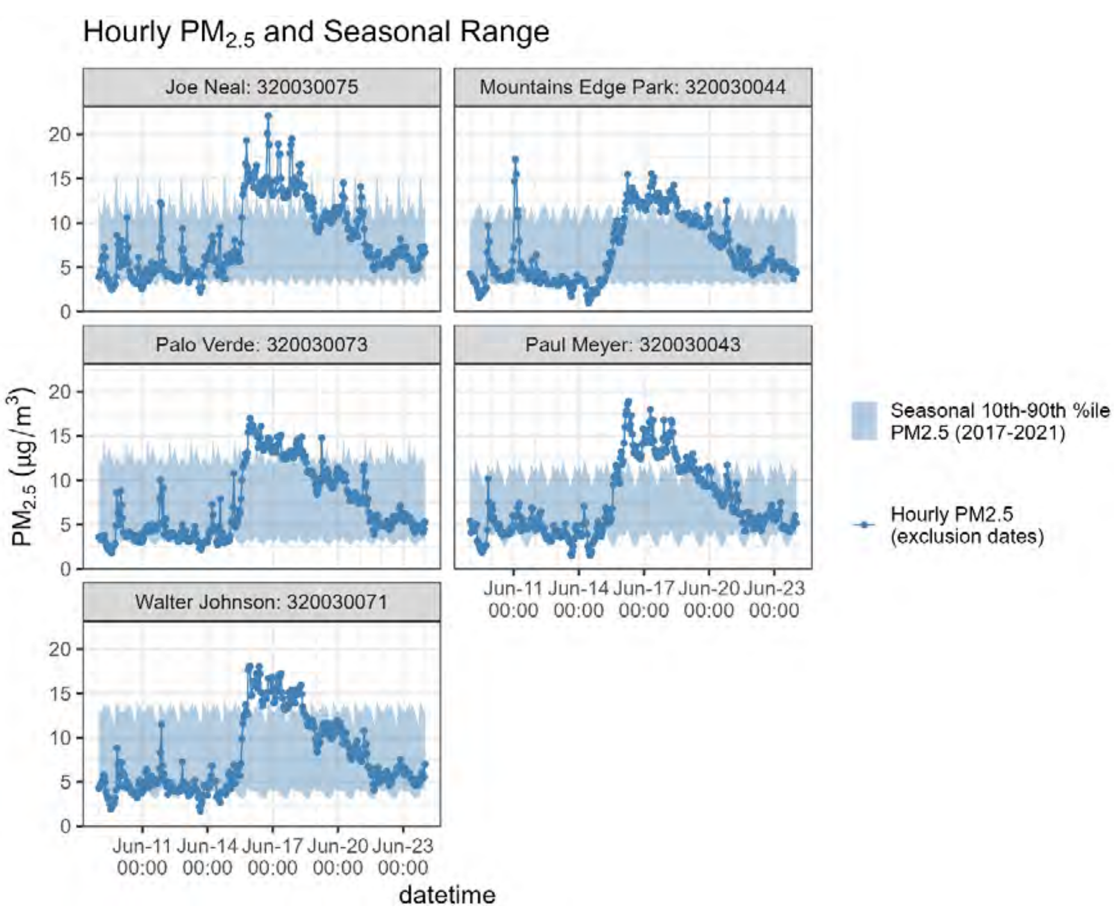

Figure 63. Hourly $PM_{2.5}$ measurements overlaid on the 10th-90th percentile diurnal concentration at each event-affected measurement site. The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021.

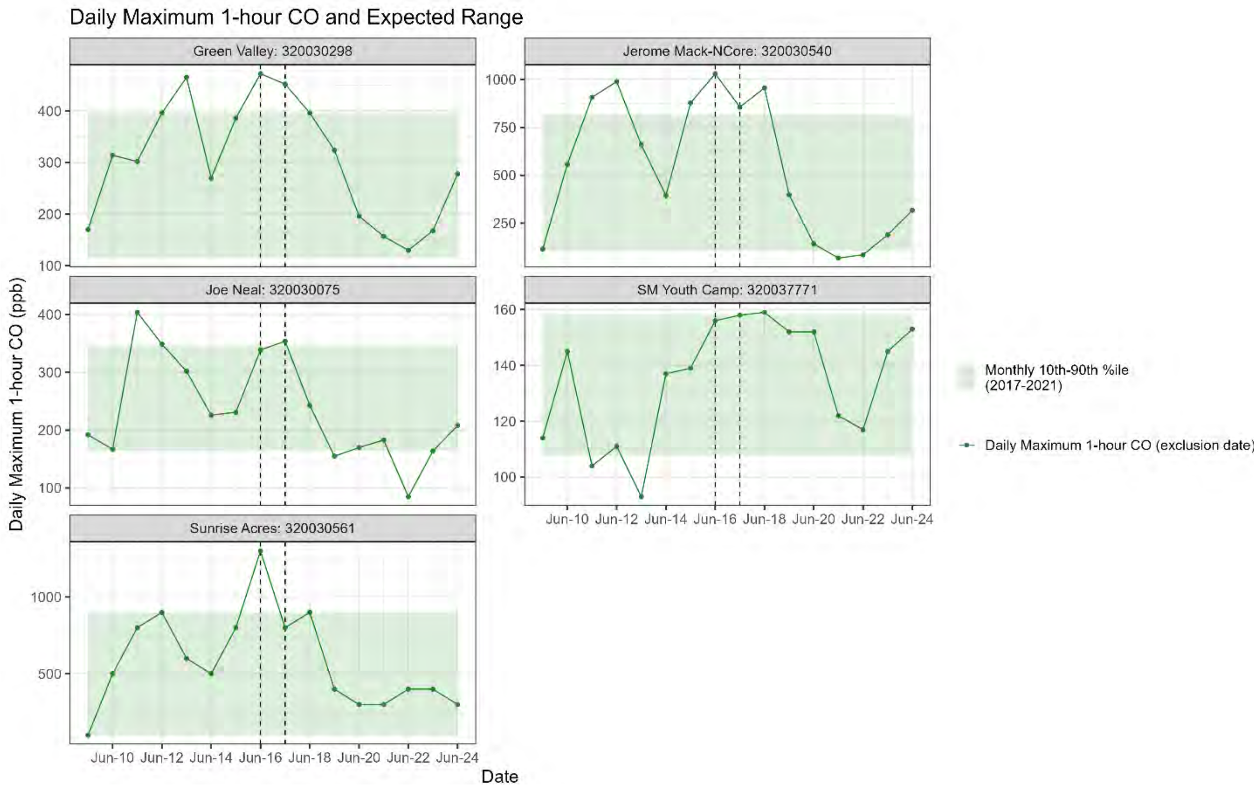

Figure 64. Daily maximum hour CO measurements overlaid on the month of June 10th-90th percentile daily maximum concentration at all Clark County CO measurement sites. The 10th-90th percentile concentration is calculated across June 2017-2021.

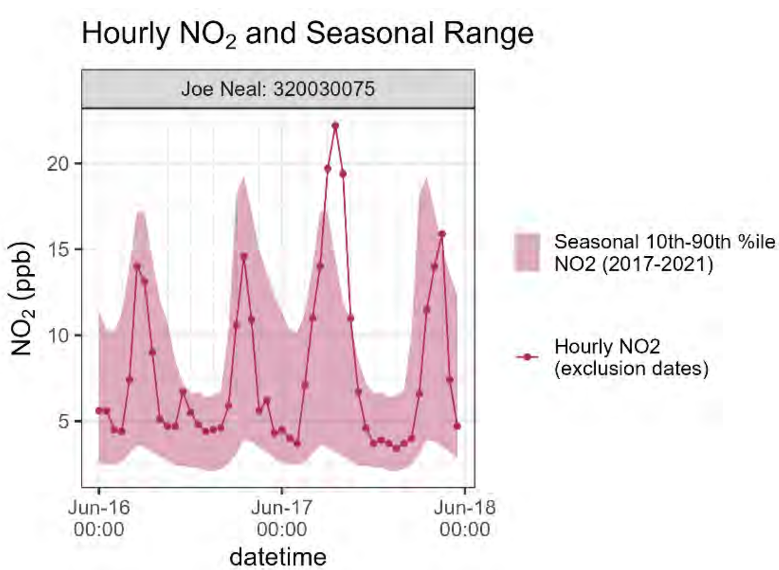

Figure 65. Hourly NO_2 measurements overlaid on the 10th-90th percentile diurnal concentration at the Joe Neal site. The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021.

Figure 66. Ratio of $PM_{2.5}$-to-PM_{10} concentrations at the affected sites during the June 16 and June 17 event period. The 5-yr average $PM_{2.5}$-to-PM_{10} diurnal ratio is displayed as a dotted line, and the 5th-95th percentile range is shown as a shaded ribbon. The 5th-95th percentile concentration range is calculated across the ozone production season (May-October) of 2017-2021.

Figure 67. Ratio of $PM_{2.5}$-to-PM_{10} concentrations at the non-affected sites during the June 16 and June 17 event period. The 5-yr average $PM_{2.5}$-to-PM_{10} diurnal ratio is displayed as a dotted line, and the 5th-95th percentile range is shown as a shaded ribbon. The 5th-95th percentile concentration range is calculated across the ozone production season (May-October) of 2017-2021.

4.2.5 Event Statistics

Table 13 summarizes the daily measurements of ozone, $PM_{2.5}$, and CO concentrations on the exclusion dates, June 16 and 17, as well as the percentile rank of the observation compared to the previous five years of data (2017-2021). Ozone MDA8 measurements were above the 95th percentile at the Paul Meyer, Palo Verde, and Joe Neal sites on June 16, 2021, as well as at the Paul Meyer and Mountains Edge Park sites on June 17, 2021. $PM_{2.5}$ measurements were above the 90th percentile at all sites on both days. In general, CO measurements in Clark County, Nevada, were higher than typical values for June. Of the sites proposed to be a part of the exclusion event, only the Joe Neal site has a CO monitor, and the value on June 16 was in the 89th percentile. CO measurements for representative sites in Clark County that have at least five years of data (Jerome Mack and Sunrise Acres) are also included for additional context for the elevated CO observations across the region, and show values greater than the 99th percentile for June 16 and greater than the 75th percentile for June 17.

Table 13. Percentile of pollutant measurements on exclusion day compared with most recent five years* (2017-2021). The percentile rank is calculated across the ozone production season (May 1-October 31) of 2017-2021 for ozone and $PM_{2.5}$, and across June 2017-2021 for CO. Data from nearby sites not identified for exclusion are shown in grey italics.

Date	Site Name	Site Code	Ozone		$PM_{2.5}$		CO	
			Ozone MDA8 (ppb)	Percent Rank	$PM_{2.5}$ 24-hr Avg (µg/m^3)	Percent Rank	CO 1-hr Daily Max (ppb)	Percent Rank (June)
6/16/2021	Paul Meyer	320030043	71	95.4	14.6	95.3		
6/16/2021	Walter Johnson	320030071	71	93.2	15.6	94.8*		
6/16/2021	Palo Verde	320030073	74	98.4	14.6	94.0*		
6/16/2021	Joe Neal	320030075	72	95.7	15.2	95.5*	339	89.3*
6/16/2021	*Jerome Mack-NCore*	*320030540*					*1,030*	*99.3*
6/16/2021	*Sunrise Acres*	*320030561*					*1,300*	*100*
6/17/2021	Paul Meyer	320030043	72	96.4	14.4	95.1		
6/17/2021	Mountains Edge Park	320030044	75	98.6*	12.8	93.5*		
6/17/2021	*Jerome Mack-NCore*	*320030540*					856	91.9
6/17/2021	*Sunrise Acres*	*320030561*					800	76.9

*Sites that have less than five years of data available for a given parameter.

4.3 July 20, 2021

4.3.1 Event Summary

The unrepresentative ozone event took place on July 20, 2021, and affected four sites in Clark County, Nevada: Green Valley, Joe Neal, Walnut Community Center, and Walter Johnson. The MDA8 concentrations at the effected sites ranged from 71-74 ppb: 74 ppb at Walnut Community Center, and 71 ppb at Joe Neal, Green Valley, and Walter Johnson. Time series graphs showing hourly ozone concentrations that exceeded the seasonal hourly means (calculated using May 1-October 31, 2017-2021) and 10th-90th hourly percentiles at each site are shown in Figure 68. On July 20, hourly ozone measurements rose sharply above (>10%) the mean beginning as early as 09:00 PST, and measurements exceeded the 90th percentile between 11:00 to 18:00 PST.

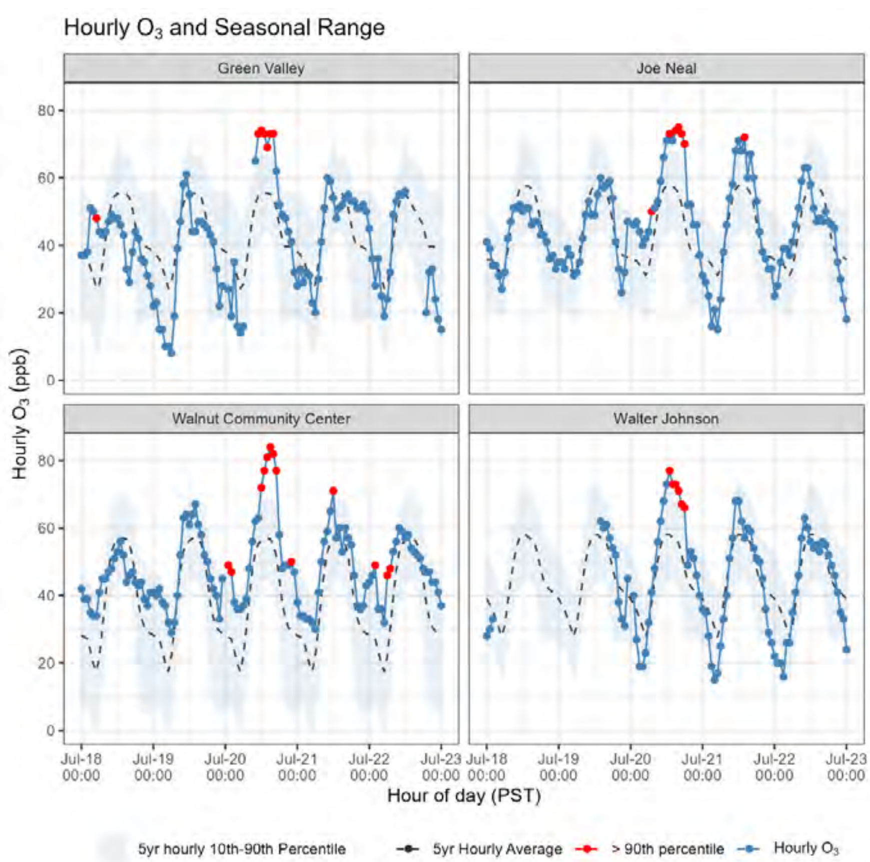

Figure 68. Hourly ozone concentrations (ppb) compared to 5-yr* ozone season (May 1-October 31) hourly means and 10th-90th percentiles. *Note: data from the Walnut Community Center site are only available for June 1-October 31, 2021.

Regional wildfire smoke from the Tamarack, Dixie, and Bootleg Fires were identified to likely contribute significant emissions that led to this event. Major evidence for wildfire smoke transport beginning July 18 includes (1) HMS smoke perimeters over Clark County; (2) HYSPLIT dispersion modeling showing accumulation of smoke in Clark County from July 18-20; (3) enhanced $PM_{2.5}$, CO, and NO_2 concentrations during expected daily minima. The combined evidence suggests that regional wildfire smoke entered the area on July 18 and lingered through the early morning on July 20, influencing the atypical ozone event that occurred on July 20, which is an unrepresentative event for base and future design value ozone assessments.

4.3.2 Identification of Wildfires

Numerous wildfires were active on July 20, 2021, the exclusion day, and contributed to regional smoke. Three major wildfires with significant emissions that contributed to the regional smoke were identified: the Tamarack and Dixie Fires in California and the Bootleg Fire in Oregon (**Figure 69**). Regional smoke from these fires was present during mid-late July 2021 throughout the northwest/western U.S., which was verified for the days of July 18-20 through visualization of smoke and wildfire detection geodata provided by the NOAA HMS (**Figure 70**). **Table 14** presents the state location, total acres within the fire perimeter, actively burning acres on or burned by the exclusion day, and the start and containment dates for each fire based on data from the WFIGS Current Interagency Fire Perimeters and the Satellite Fire Occurrence and Growth database.[10]

[10] McClure et al. (2023) Consistent, high-accuracy mapping of daily and sub-daily wildfire growth with satellite observations. International Journal of Wildland Fire 32, 694-708. Available at https://www.publish.csiro.au/wf/ExportCitation/WF22048.

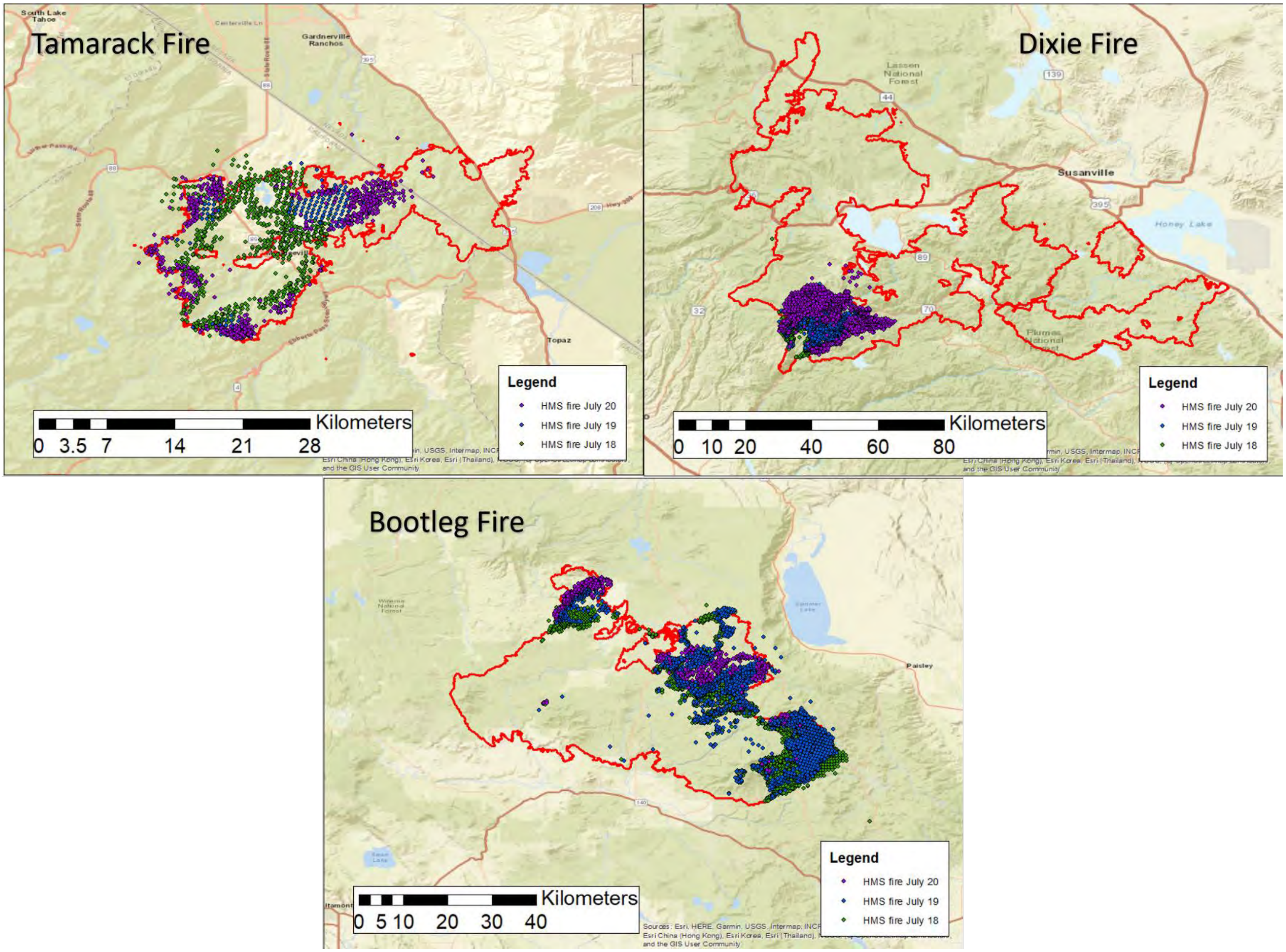

Figure 69. Final fire perimeters (red) and HMS fire detections for the Tamarack, Dixie, and Bootleg Fires from July 18-20, 2021.

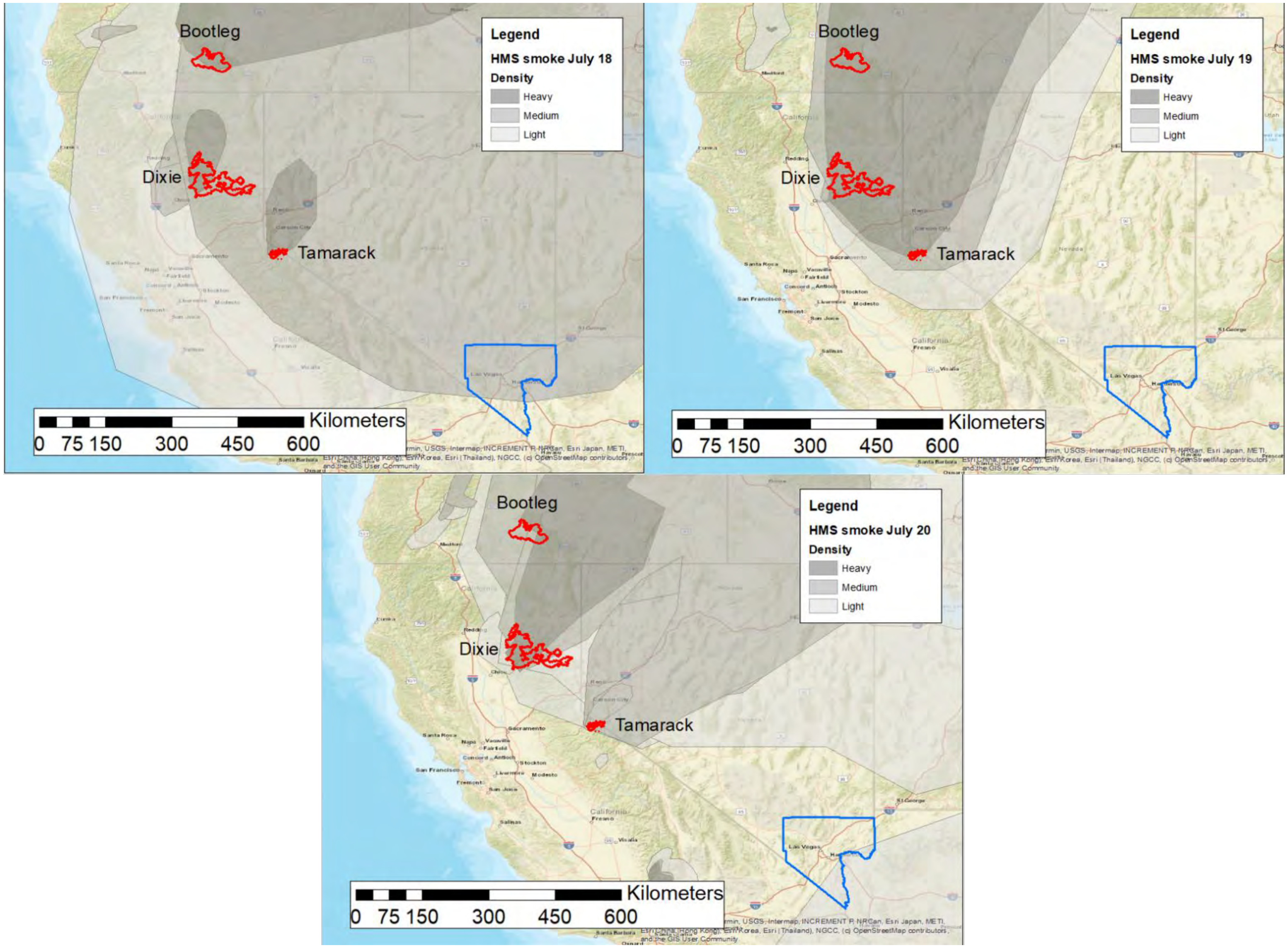

Figure 70. Maps of HMS smoke boundaries for July 18-20, 2021, with qualitative smoke density. Fire perimeters from the major fires contributing to the exclusion date are shown in red and the Clark County, NV, boundary is shown in blue.

Table 14. Wildfires affecting Clark County on the exclusion day. Where active acres are not available, cumulative acres burned are listed in italics.

Wildfire Name	State	Total Acres	Active Acres on or by July 20	Start Date	Containment Date
Tamarack	California	68,637	12,292	July 4	October 16
Dixie	California	963,309	40,820	July 14	October 15
Bootleg	Oregon	413,765	*388,359*	July 6	August 14

4.3.3 Dispersion Modeling and Regional Analysis

HYSPLIT dispersion modelling was performed from July 13 through 20, 2021. Dispersion was initiated on July 13 at 12:00 PST from the three identified active fires impacting the exclusion date and modeled through the exclusion date to simulate the smoke patterns observed in satellite imagery and HMS smoke data. GDAS data at 1.0° horizontal resolution was used for meteorological input. Output from the dispersion modeling was integrated over a 48-hr period, from July 18 at 18:00 PST through July 20 at 18:00 PST. This time period was chosen to correspond with the initial increase of observed $PM_{2.5}$ concentrations in Clark County. The accumulation of smoke at 0-100 m for the 48-hr period is shown in Figure 71.

The HYSPLIT dispersion modeling shows that smoke from multiple fires produced a dense layer of smoke that wrapped around a high-pressure system and spread throughout the region, including Clark County, Nevada. The modeling results are consistent with the HMS smoke plume (shown in gray in Figure 71); HMS is an independent smoke identification database. The dispersion results show that smoke from multiple fires reached Clark County on July 20, 2021, and the smoke was present in the lower mixed layer, impacting the surface conditions. These results are also consistent with upper-air meteorological analyses shown in Figure 72, which indicate that a high-pressure system along the Nevada/Utah border generated southeasterly winds aloft into southern Nevada, allowing smoke to be transported into Clark County.

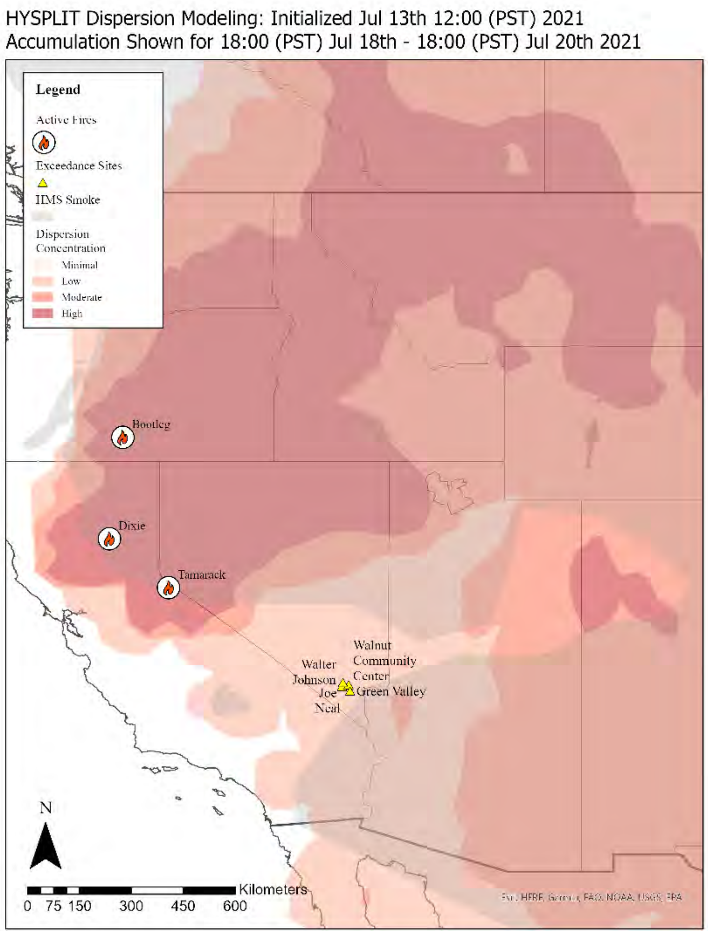

Figure 71. HYSPLIT dispersion modeling for three large fires (labeled as "Active Fires") in California and Oregon. GDAS 1.0° meteorological data was used, and dispersion was initiated on July 13, 2021, at 12:00 PST to model the regional smoke observed in satellite and HMS products. HMS smoke is shown in gray and qualitative concentrations of particulate matter are shown in shades of red. Accumulation of particulate matter is shown at 0-100 m for 18:00 PST on July 18 through 18:00 PST on July 20, 2021.

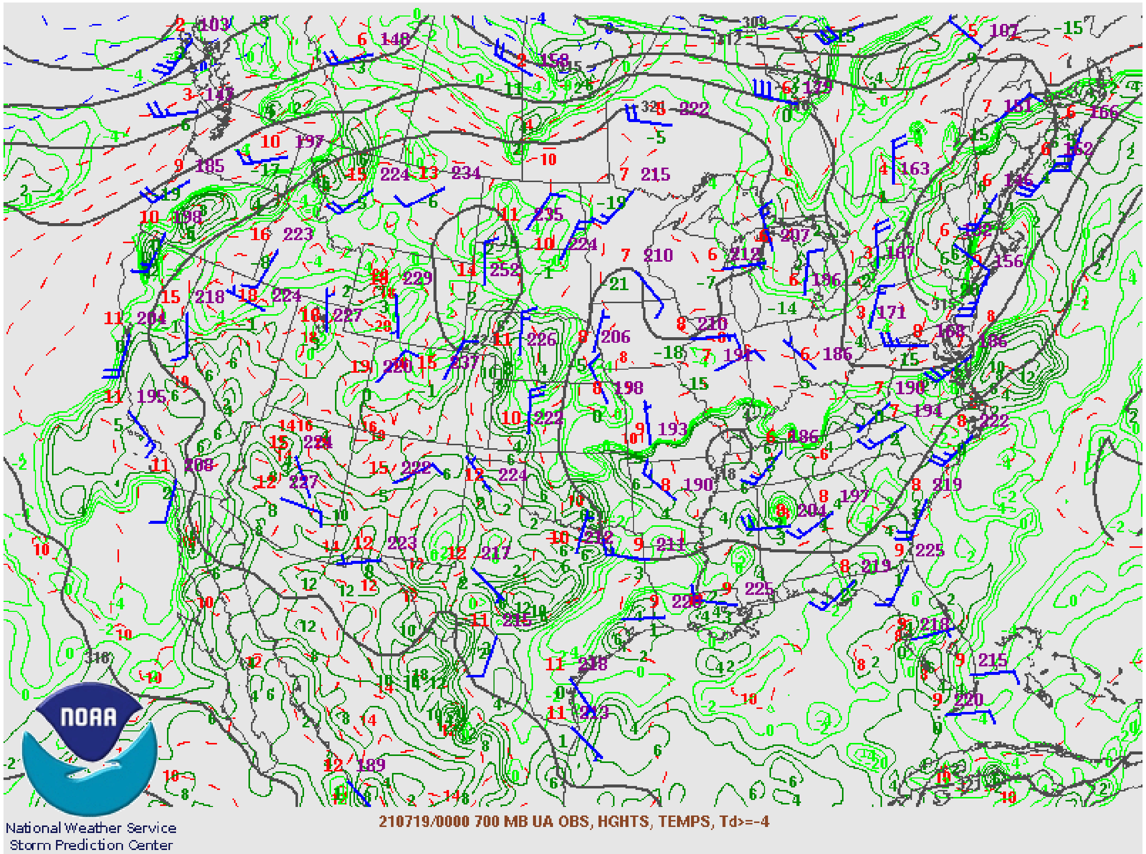

Figure 72. 700-mb map valid at 00:00 UTC on July 19, 2021 (16:00 PST on July 18, 2021). Upper-level high pressure along the Nevada/Utah border generated southeasterly winds aloft into southern Nevada, allowing smoke to be transported into Clark County.

4.3.4 Surface Impacts

The movement of wildfire smoke into the area on July 18 is shown by elevated concentrations of $PM_{2.5}$, CO, and NO_2 during expected diurnal minimums, shown in Figure 73 through Figure 75. The 10th-90th percentile range shown in Figure 73 through Figure 75 are calculated using five years of data (2017-2021) during the ozone season (May – October). A spike in $PM_{2.5}$ above the 90th percentile diurnal concentration was measured at both the Green Valley and Jean sites at 14:00 PST on July 18 (Figure 73, dashed line). This increase in $PM_{2.5}$ concentration occurs in the afternoon when daily $PM_{2.5}$ measurements are expected to be at a minimum.

Both CO (Figure 74) and NO_2 concentrations (Figure 75) also show concentrations above the 90th percentile diurnal concentration during the afternoon of July 18. Near 16:00 PST (first dashed line), CO and NO_2 measurements show increases to a local maximum, again a time period in the diurnal cycle where concentrations are expected to be at a minimum. This pattern is mirrored at the three measurement sites in Clark County for NO_2 concentrations, and was repeated on the following day, July 19 near 13:00 PST (second dashed line).

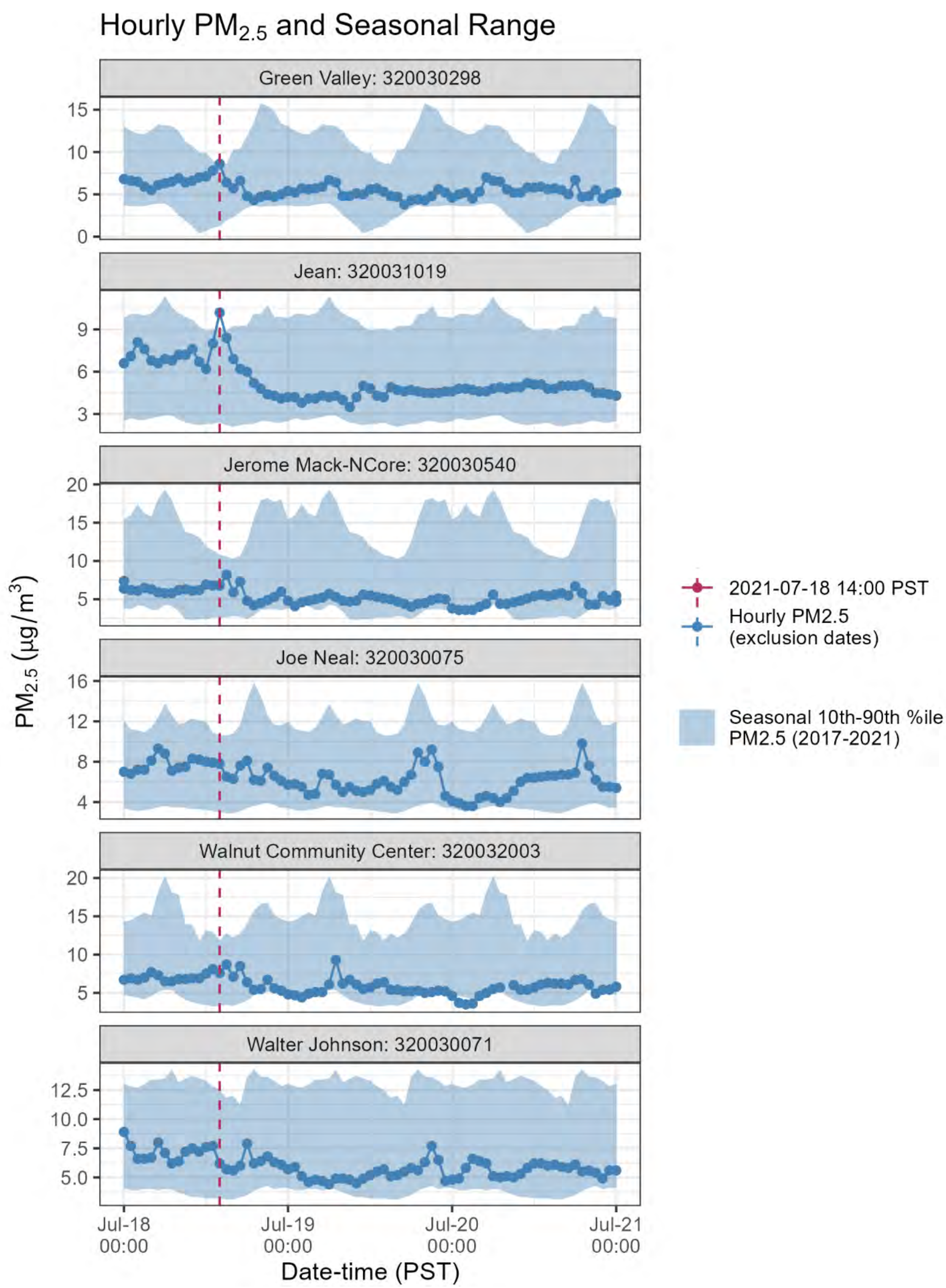

Figure 73. Hourly $PM_{2.5}$ measurements overlaid on the 10th-90th percentile diurnal concentration at the affected sites. The dashed line is 14:00 PST on July 18, 2021. The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021.

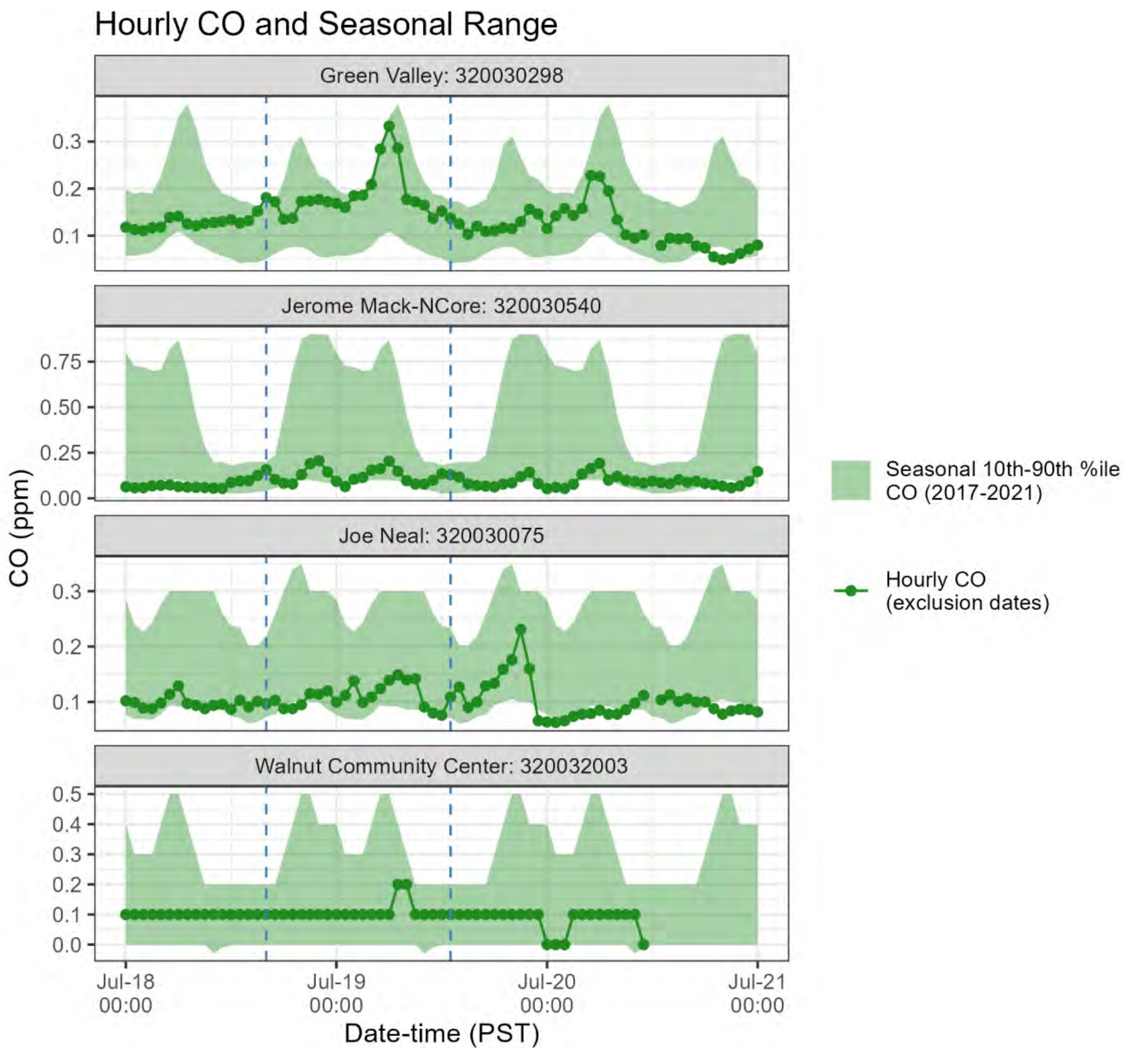

Figure 74. Hourly CO measurements overlaid on the 10th-90th percentile diurnal concentration at representative (Jerome Mack-NCore) and affected sites (Green Valley, Joe Neal, and Walnut Community Center). The dashed lines are (1) 13:00 PST on July 18, 2021, and (2) 16:00 PST on July 19, 2021. The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021.

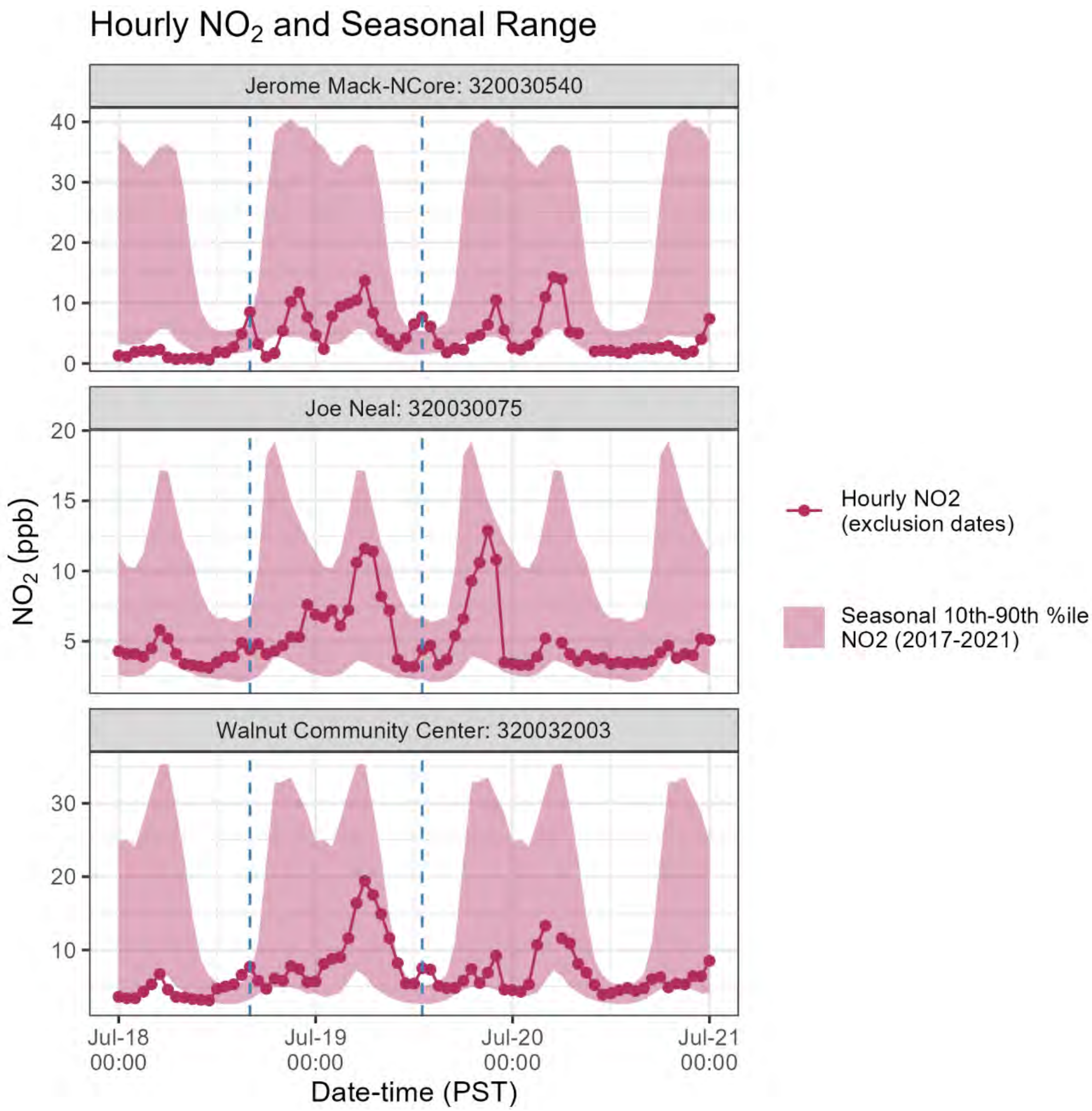

Figure 75. Hourly NO_2 measurements overlaid on the 10th-90th percentile diurnal concentration at representative (Jerome Mack-NCore) and affected sites (Joe Neal and Walnut Community Center). The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021.

The ratio of $PM_{2.5}$-to-PM_{10} concentrations was also examined to determine if wildfire smoke entered Clark County on or before the exclusion dates. Increases in this ratio are indicative of wildfire smoke. Figure 76 shows a time series of the $PM_{2.5}$-to-PM_{10} ratio from July 18-July 22 at the Jean monitoring site (upwind of Clark County's anthropogenic emissions), compared to the ozone season mean and 5th-95th percentile range for available data between 2017-2021. Measurements from the Jean site show an above-normal enhancement of the $PM_{2.5}$-to-PM_{10} ratio starting late on July 18 and continuing through early morning on July 20. This observation compliments the $PM_{2.5}$, CO, and NO_2 enhancements that occurred July 18-19, suggesting that wildfire smoke entered the area on July 18 and lingered through early morning on July 20, influencing the atypical ozone event that occurred on

July 20. The $PM_{2.5}$-to-PM_{10} ratio at other affected sites, shown in **Figure 77** do not show the clear trend observed in the upwind Jean site. The Jean site is upwind of Clark County's anthropogenic emissions, and thus gives an indication of regional background levels at the time of the event.

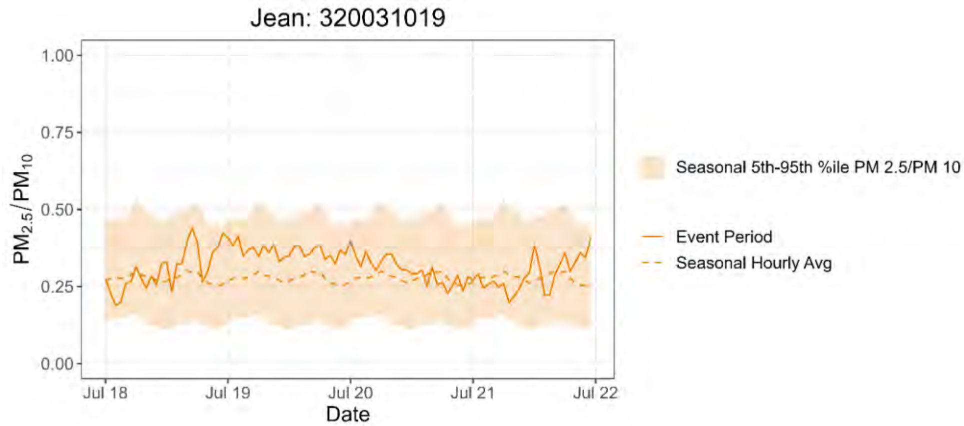

Figure 76. Ratio of $PM_{2.5}$-to-PM_{10} concentrations at the Jean site before and during the July 20 event period. The 5-yr average $PM_{2.5}$-to-PM_{10} diurnal ratio is displayed as a dotted line, and the 5th-95th percentile range is shown as a shaded ribbon. The 5th-95th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021.

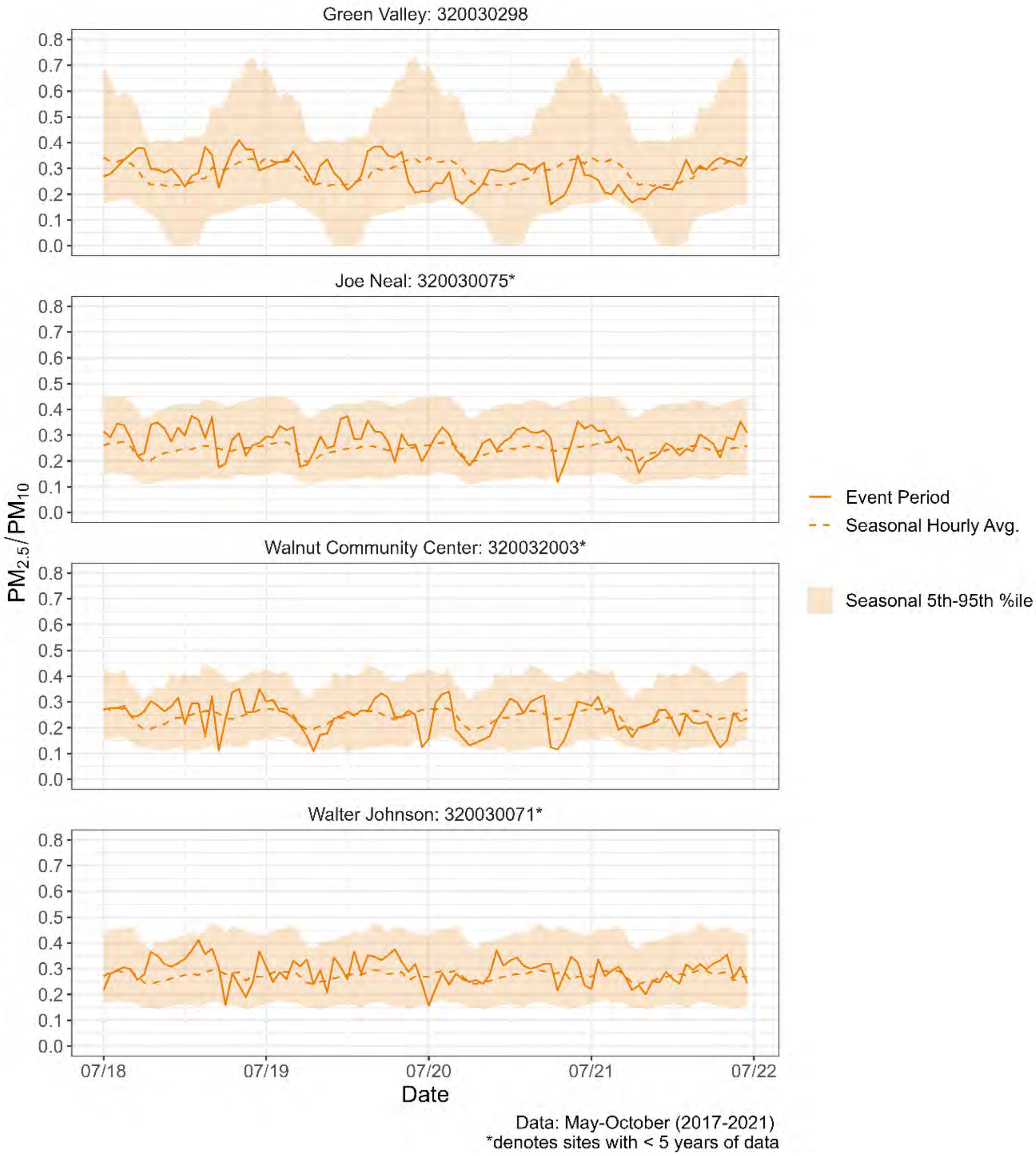

Figure 77. Ratio of $PM_{2.5}$-to-PM_{10} concentrations at all affected sites before and during the July 20 event period. The 5-yr average $PM_{2.5}$-to-PM_{10} diurnal ratio is displayed as a dotted line, and the 5th-95th percentile range is shown as a shaded ribbon. The 5th-95th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021.

To confirm the lingering presence of smoke between July 18-19 and the exclusion date of July 20, meteorological data is shown in Figure 78. An hourly temperature, wind, and visibility timeseries for data collected at the Harry Reid International Airport beginning on July 18 shows light and variable winds from the evening of July 18 through 20, allowing pollutants to accumulate after the injection of smoke overnight on July 18-19 in southern Clark County, NV, and produce atypical levels of ozone on July 20.

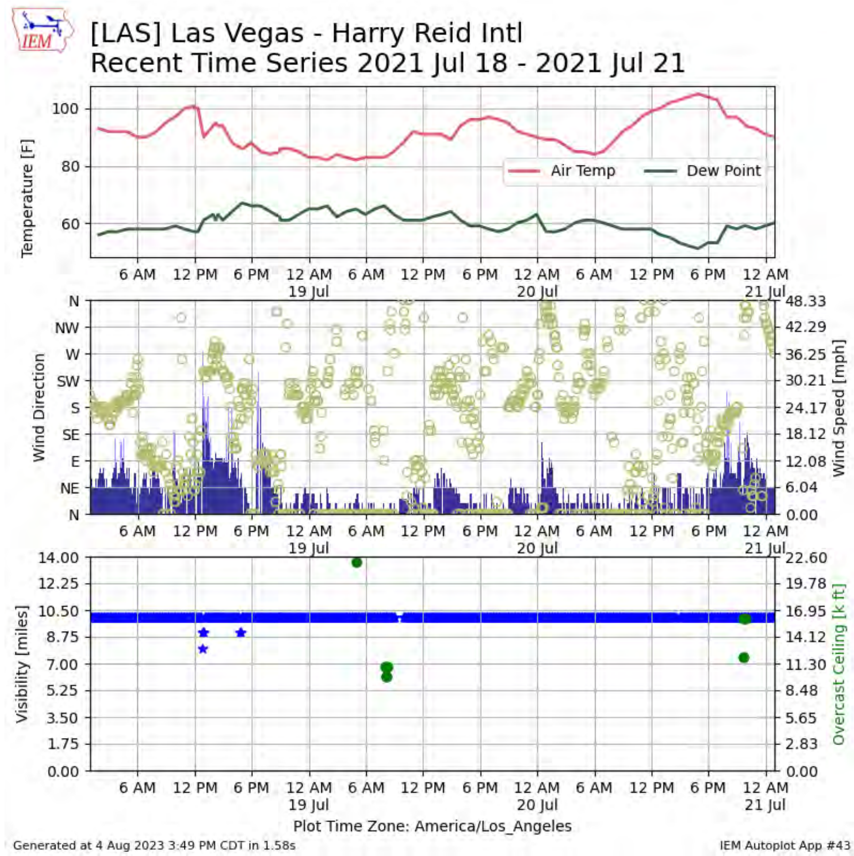

Figure 78. Timeseries of hourly ASOS temperature, wind, visibility measurements at the Harry Reid International Airport, beginning July 18, 2021. Light and variable winds from the evening of July 18 through July 20 allowed pollutants to accumulate in southern Clark County, NV.

4.3.5 Event Statistics

Table 15 and Table 16 summarize the daily measurements of ozone, $PM_{2.5}$, CO, and NO_2 concentrations leading up to the exclusion day, as well as the percentile rank of the observation compared to the previous five years of data (2017-2021). As highlighted in Figure 73 through Figure 75, $PM_{2.5}$, CO, and NO_2 concentrations began to see enhancements during typical afternoon minima on July 18. These anomalies are most clearly visualized in Figure 73 through Figure 75, and average daily measurements do not accurately capture the hour-to-hour anomalies. Therefore, in addition to the daily measurement statistics for these pollutants (Table 15), in Table 16 a 6-hr averaging period during the expected daily minimum period (12:00-18:00 PST) was used to compare exclusion dates to the previous five years of data. On July 18, these 6-hr average $PM_{2.5}$ concentrations ranked from the 70th-80th percentile, CO concentrations ranged from the 28th-67th percentile, and NO_2 concentrations ranged from the 24th-70th percentile. Afternoon $PM_{2.5}$ concentrations at most sites remained elevated above the 50th percentile through July 20. Ozone MDA8 measurements were low before the influx of wildfire-related emissions (10th-25th percentile on July 18), and then ranged from the 93rd-98th percentile on July 20.

Table 15. Percentile of pollutant measurements on the exclusion day compared with most recent five years* (2017-2021). The percentile rank is calculated across the ozone production season (May 1-October 31) of 2017-2021. Data from nearby sites not identified for exclusion are shown in grey italics.

Date	Site Name	Site Code	Ozone		$PM_{2.5}$		CO		NO_2	
			Ozone MDA-8 (ppb)	Percent Rank	$PM_{2.5}$ 24-hr Avg ($\mu g/m^3$)	Percent Rank	CO 1-hr Daily Max (ppb)	Percent Rank	NO_2 1-hr Daily Max (ppb)	Percent Rank
7/18/2021	Joe Neal	320030075	49	22.1	7.3	70.1*	129	3.6*	7.6	10.4
7/18/2021	Green Valley	320030298	46	17.8	6.1	53	181	23.6*	--	--
7/18/2021	Walnut Comm. Center	320032003	49	25.5*	6.8	37.9*	100	5.2*	7.8	4.6*
7/18/2021	*Jerome Mack-NCore*	*320030540*	*43*	*15*	*6*	*34.5*	*207*	*18.4*	*11.8*	*12.2*
7/18/2021	*Jean*	*320031019*	*45*	*11.9*	*6.6*	*73.5*	--	--	--	--
7/19/2021	Walter Johnson	320030071	57	47.5	5.3	31.4*	--	--	--	--
7/19/2021	Joe Neal	320030075	55	41.4	6	53.8*	231	36.7*	12.9	37.3
7/19/2021	Green Valley	320030298	50	28	5.2	33.3	333	70*	--	--
7/19/2021	Walnut Comm. Center	320032003	61	67.3*	5.5	14.4*	200	18.3*	19.4	27.5*
7/19/2021	*Jerome Mack-NCore*	*320030540*	*52*	*47.3*	*4.8*	*16.7*	*204*	*18.2*	*13.7*	*15.4*
7/19/2021	*Jean*	*320031019*	*49*	*24*	*4.3*	*36.4*	--	--	--	--
7/20/2021	Walter Johnson	320030071	71	93.2	5.6	38.8*	--	--	--	--
7/20/2021	Joe Neal	320030075	71	94.6	5.6	45.1*	113	2.2*	5.2	2.8
7/20/2021	Green Valley	320030298	71	96.2	5.4	36.7	228	37.8*	--	--
7/20/2021	Walnut Comm. Center	320032003	74	98*	5.4	13.1*	100	5.2*	13.3	13.1*
7/20/2021	*Jerome Mack-NCore*	*320030540*	*68*	*96.5*	*4.8*	*16.7*	*192*	*11.3*	*14.3*	*16.1*
7/20/2021	*Jean*	*320031019*	*54*	*46.7*	*4.8*	*46.5*	--	--	--	--

*Sites that have less than five years of data available for a given parameter.

Table 16. Percentile of pollutant measurement between 12:00 and 18:00 PST on the exclusion day compared with most recent five years* (2017-2021). The percentile rank is calculated across the ozone production season (May 1-October 31) of 2017-2021. Data from nearby sites not identified for exclusion are shown in grey italics.

Date	Site Name	Site Code	Ozone		$PM_{2.5}$		CO		NO_2	
			Ozone MDA-8 (ppb)	Percent Rank	$PM_{2.5}$ 12:00 – 18:00 PST Mean ($\mu g/m^3$)	Percent Rank	CO 12:00 – 18:00 PST mean (ppb)	Percent Rank	NO_2 12:00 – 18:00 PST mean (ppb)	Percent Rank
7/18/2021	Green Valley	320030298	46	17.8	6.7	72.2	147.6	67.7*	--	--
7/18/2021	Joe Neal	320030075	49	22.1	7.5	79.1*	95.7	28.5*	4.21	41.8
7/18/2021	Walnut Comm. Center	320032003	49	25.5*	7.7	80.6*	100.0	30.2*	5.69	70.4*
7/19/2021	Walter Johnson	320030071	NA	--	NA	--	--	--	--	--
7/18/2021	*Jerome Mack-NCore*	*320030540*	*43*	*15*	*6.7*	*72.2*	*106.7*	*41.5*	*3.44*	*24.2*
7/18/2021	*Jean*	*320031019*	*45*	*11.9*	*7.4*	*78.6*	*--*	*--*	*--*	*--*
7/19/2021	Green Valley	320030298	50	28	4.9	45.3	122.4	53.2*	--	--
7/19/2021	Joe Neal	320030075	55	41.4	5.8	61*	109.3	43.1*	4.47	48
7/19/2021	Walnut Comm. Center	320032003	61	67.3*	5.6	58*	100.0	30.2*	5.81	72.3*
7/19/2021	Walter Johnson	320030071	57	47.5	5.4	54.8*	--	--	--	--
7/19/2021	*Jerome Mack-NCore*	*320030540*	*52*	*47.3*	*4.9*	*45.3*	*94.1*	*27.9*	*4.30*	*44.2*
7/19/2021	*Jean*	*320031019*	*49*	*24*	*4.6*	*39.7*	*--*	*--*	*--*	*--*
7/20/2021	Green Valley	320030298	71	96.2	5.7	59.7	85.7	24.1*	--	--
7/20/2021	Joe Neal	320030075	71	94.6	6.6	71.3*	104.0	40.4*	3.57	26.8
7/20/2021	Walnut Comm. Center	320032003	74	98*	6.2	66.6*	--	--	4.99	59.7*
7/20/2021	Walter Johnson	320030071	71	93.2	6	63.6*	--	--	--	--
7/20/2021	*Jerome Mack-NCore*	*320030540*	*68*	*96.5*	*5.7*	*59.7*	*89.4*	*26.1*	*2.21*	*7.7*
7/20/2021	*Jean*	*320031019*	*54*	*46.7*	*5*	*47.5*	*--*	*--*	*--*	*--*

*Sites that have less than five years of data available for a given parameter.

4.4 August 2-3, 2021

4.4.1 Event Summary

The unrepresentative ozone event took place on August 2-3, 2021. The event affected eight sites in Clark County, Nevada, on August 2, and seven sites on August 3. The MDA8 concentrations at the effected sites ranged from 72-78 ppb on August 2: 78 ppb at Palo Verde and Walnut Community Center, 77 ppb at Liberty High School, 75 ppb at Joe Neal and Mountains Edge Park, 74 ppb at Green Valley, and 72 ppb at Jerome Mack-NCore. On August 3, the MDA8 concentrations at the effected sites ranged from 72-80 ppb: 80 ppb at Mountains Edge Park, 77 ppb at Walter Johnson and Paul Meyer, 76 ppb at Liberty High School, 75 ppb at Palo Verde, 74 ppb at Walter Johnson, 73 ppb at Joe Neal, and 72 ppb at Green Valley.

On August 2, hourly ozone measurements exceeded the 90th percentiles late in the day between 19:00-23:00 PST, and throughout August 3 from 09:00 to 19:00 PST. Time series graphs showing hourly ozone concentrations that exceeded the seasonal means (calculated using data from May 1-October 31, 2017-2021) and 10th-90th percentiles at each site are shown in **Figure 79**.

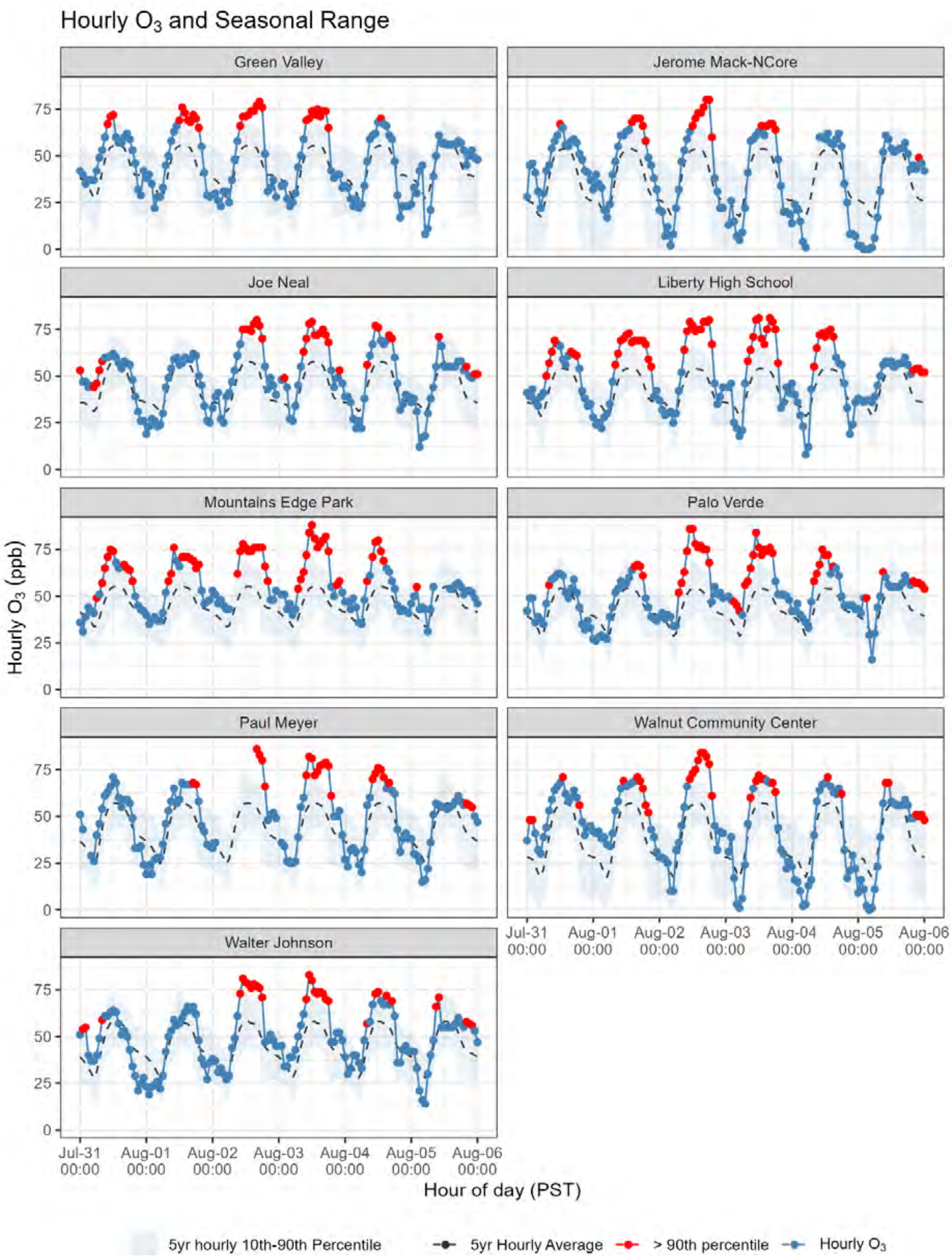

Figure 79. Hourly ozone concentrations (ppb) compared to 5-yr* ozone season (May 1-October 31) hourly means and 10-90th percentiles. *Note: data from the Liberty High School, Mountains Edge Park, and Walnut Community Center sites began less than five years ago.

An abundance of regional wildfire smoke was identified as a major contributor to this event. In particular, the Dixie, Monument, and Haypress River Complex Fires in California were major contributors of smoke, from which smoke initially traveled northeast (July 31-August 1), and then circled back around towards Clark County by August 2-3. Strong evidence of smoke enhancing ozone concentrations include (1) both HMS smoke boundaries and HYSPLIT dispersion modeling independently indicating the presence of smoke in Clark County and (2) increasing hourly $PM_{2.5}$ concentrations, hourly CO concentrations, and $PM_{2.5}$-to-PM_{10} ratios. This combination of evidence indicates that this is an unrepresentative event for assessing base and future ozone design values.

4.4.2 Identification of Wildfires

Numerous wildfires throughout the western U.S. were active on August 2 and 3, 2021. The Dixie, Monument and Haypress River Complex Fires in California (**Figure 80**) had significant emissions that contributed to the regional smoke. These fires created widespread regional smoke that was present during late July and early August 2021 throughout the northwest/western U.S. The presence of widespread smoke was verified for the days of July 31-August 3 through visualization of smoke and wildfire detection geodata provided by the NOAA HMS (**Figure 81**). The HMS plots show smoke from the California fires initially traveling northeast (July 31-August 1), and then circling back around towards Clark County by August 2-3. **Table 17** lists the state location, total acres within the fire perimeter, actively burning acres on the exclusion day, and the start and containment dates for each fire based on data from the WFIGS Current Interagency Fire Perimeters and the Satellite Fire Occurrence and Growth database.[11]

[11] McClure et al. (2023) Consistent, high-accuracy mapping of daily and sub-daily wildfire growth with satellite observations. International Journal of Wildland Fire 32, 694-708. Available at https://www.publish.csiro.au/wf/ExportCitation/WF22048.

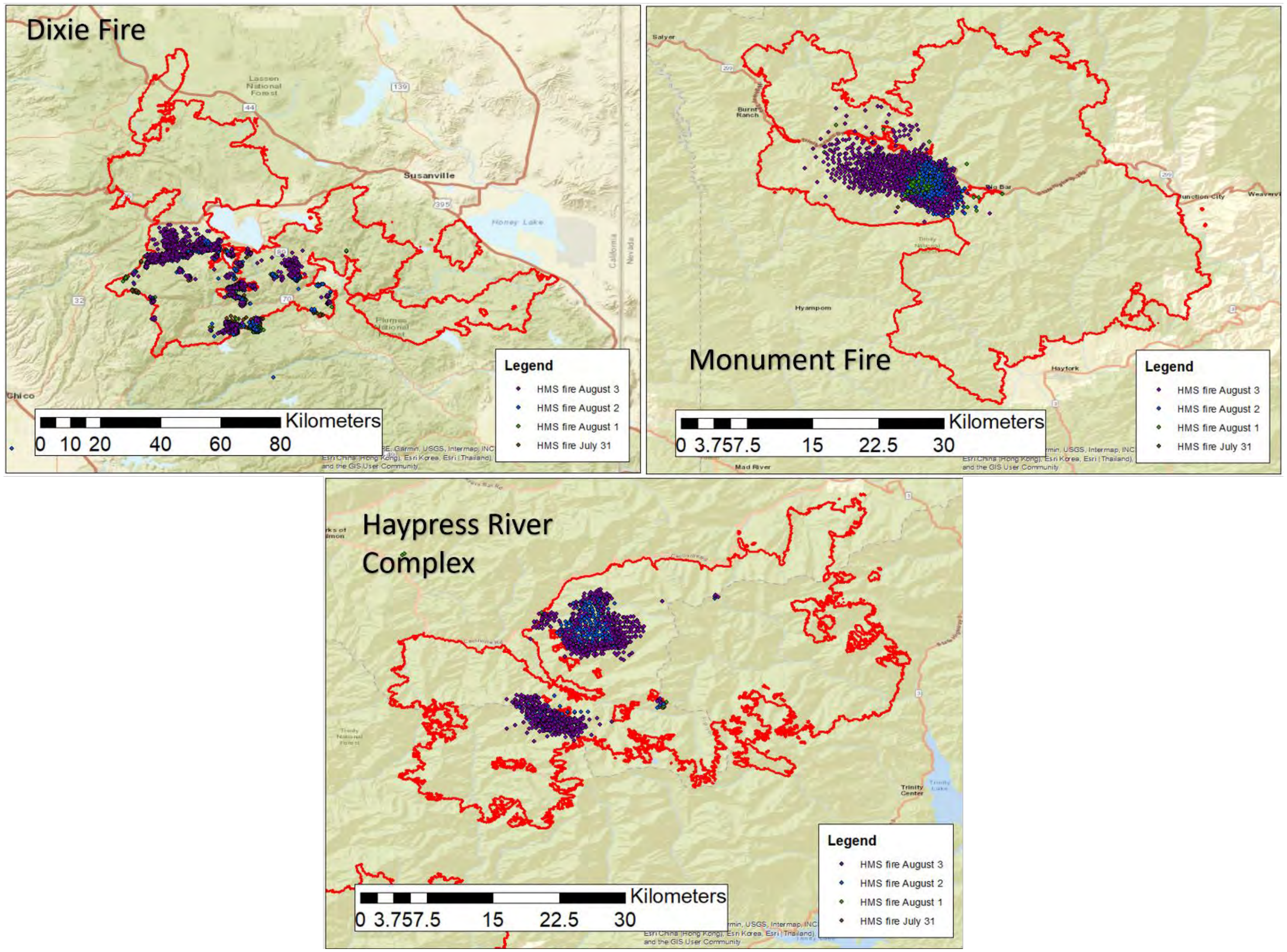

Figure 80. Final fire perimeters (red) and HMS fire detections for the Dixie, Monument, and Haypress River Complex Fires during July 31-August 3, 2021.

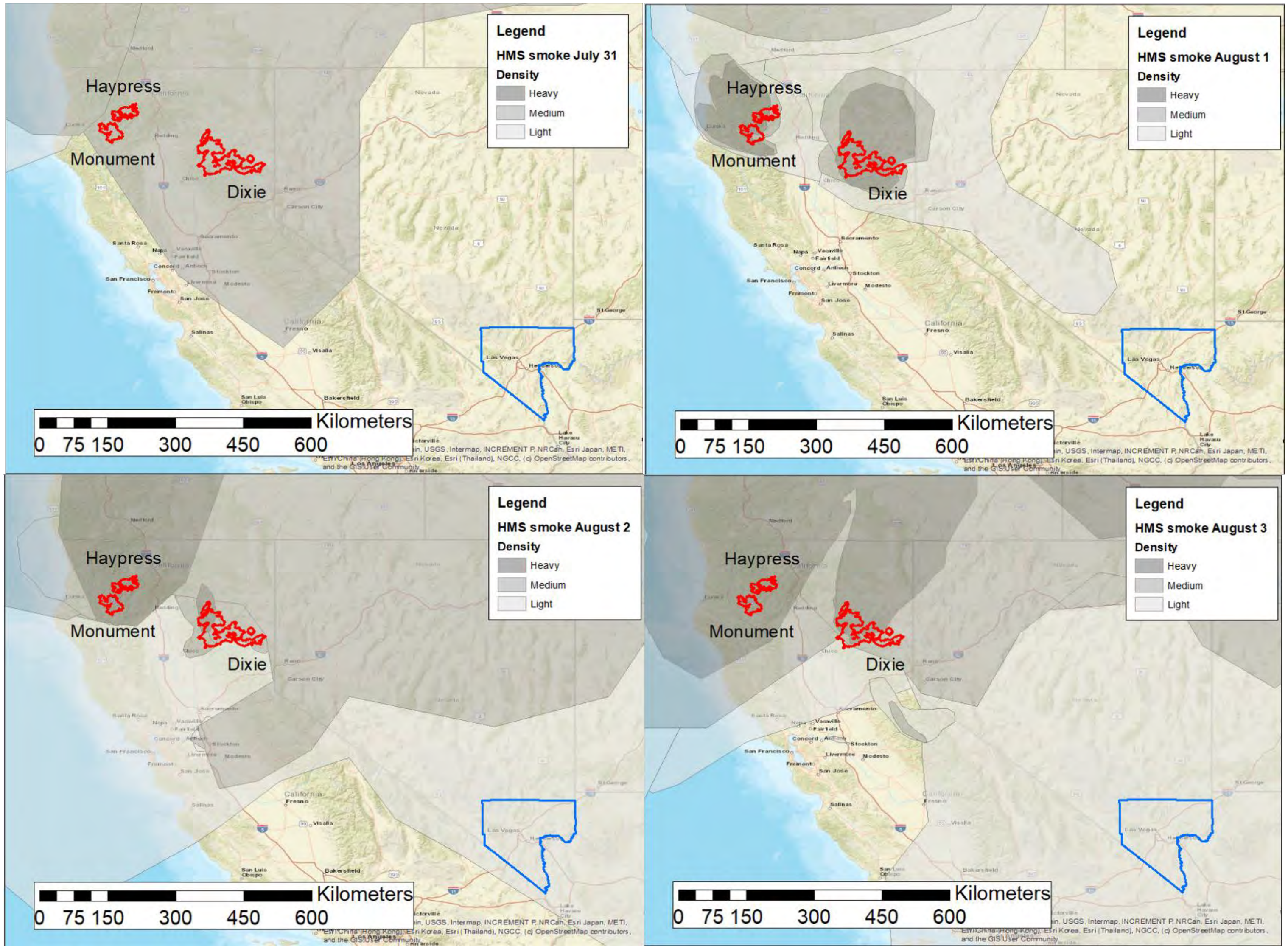

Figure 81. HMS smoke boundaries for July 31-August 3, 2021, with qualitative smoke density. Fire perimeters from the major fires contributing to the exclusion date are shown in red and the Clark County, NV, boundary is shown in blue.

Table 17. Wildfires affecting Clark County on the exclusion days. The fire name, state location, total acreage, active acreage burning on the exclusion day, and the start and containment dates are included.

Wildfire Name	State	Total Acres	Active Acres August 2	Active Acres August 3	Start Date	Containment Date
Dixie	California	963,309	24,180	22,459	July 14	October 15
Monument	California	223,124	6,279	8,883	July 31	October 20
Haypress River Complex	California	199,343	7,619	10,964	July 31	October 25

4.4.3 Dispersion Modeling and Regional Analysis

HYSPLIT dispersion modeling was performed for July 31-August 3, 2021. Dispersion was initiated at 00:00 PST from the three identified active fires impacting the exclusion date. GDAS data at 1.0° horizontal resolution was used for meteorological input. Output from the dispersion modeling was integrated over a 48-hr period, from August 2 at 00:00 PST through August 4 at 00:00 PST. This time range was chosen to correspond with the initial increase of observed $PM_{2.5}$ concentrations in Clark County. The accumulation of smoke at 0-100 m for the 24-hr period is shown in Figure 82.

The results of the HYSPLIT dispersion modeling show that smoke from multiple fires produced a dense layer of smoke that blanketed the western U.S. region, including Clark County, NV. The modeling results are consistent with the HMS smoke plume data (shown in gray in Figure 82); HMS is an independent smoke identification database. The dispersion results show smoke from multiple fires reached Clark County on August 2-3, 2021, and the smoke was present in the lower mixed layer, impacting the surface conditions.

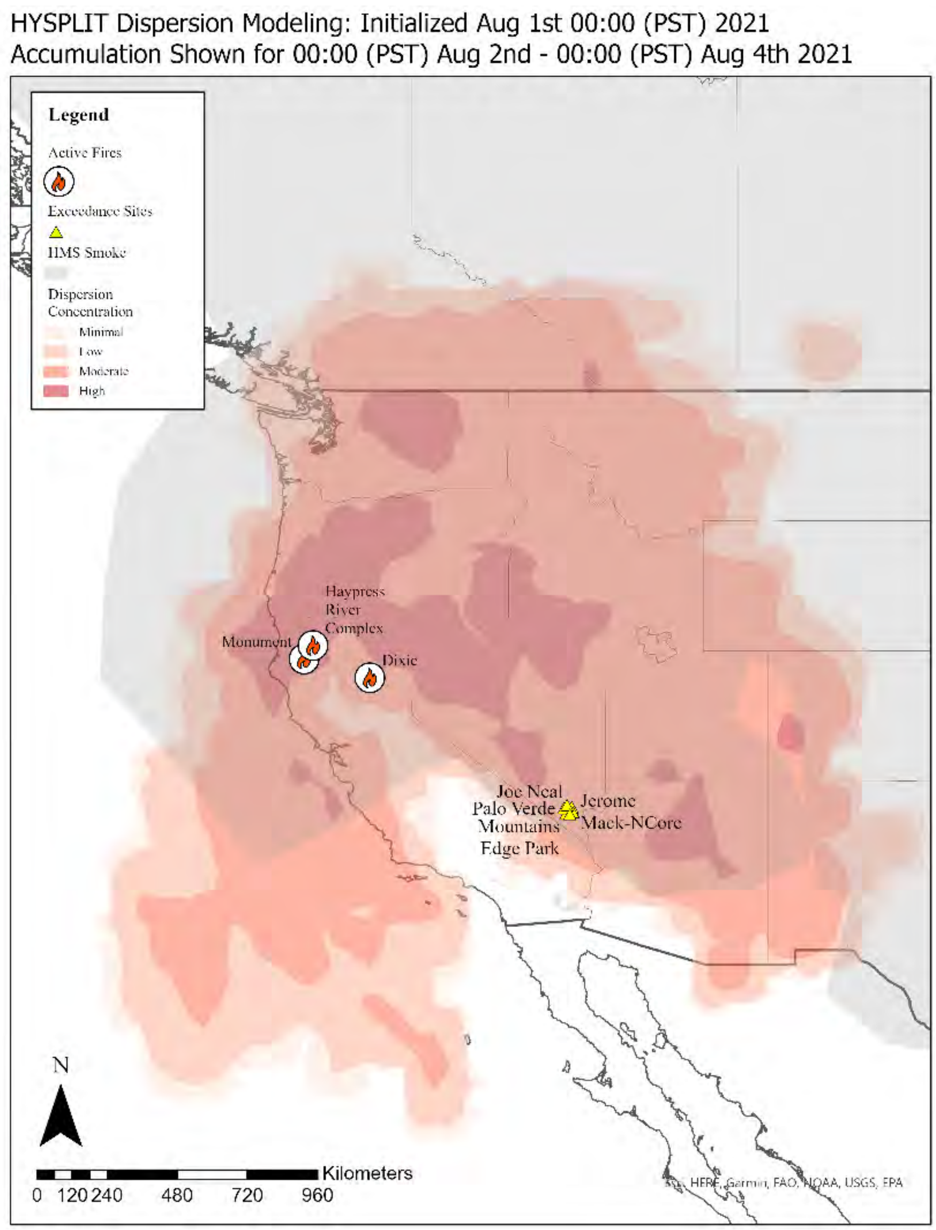

Figure 82. Results of the HYSPLIT dispersion modeling for three large fires (labeled as "Active Fires") in California. GDAS 1.0° meteorological data was used, and dispersion was initiated on August 1, 2021, at 00:00 PST to model the regional smoke observed in satellite and HMS products. HMS smoke is shown in gray and qualitative concentrations of particulate matter are shown in shades of red. Accumulation of particulate matter is shown at 0-100 m for 00:00 PST on August 2 through 00:00 PST on August 4, 2021.

Regional weather conditions were mild as a high-pressure system moved eastward during August 1-3, 2021 (Figure 83). This is consistent with the dispersion modeling results, which show widespread smoke from California wildfires (shown in Figure 82).

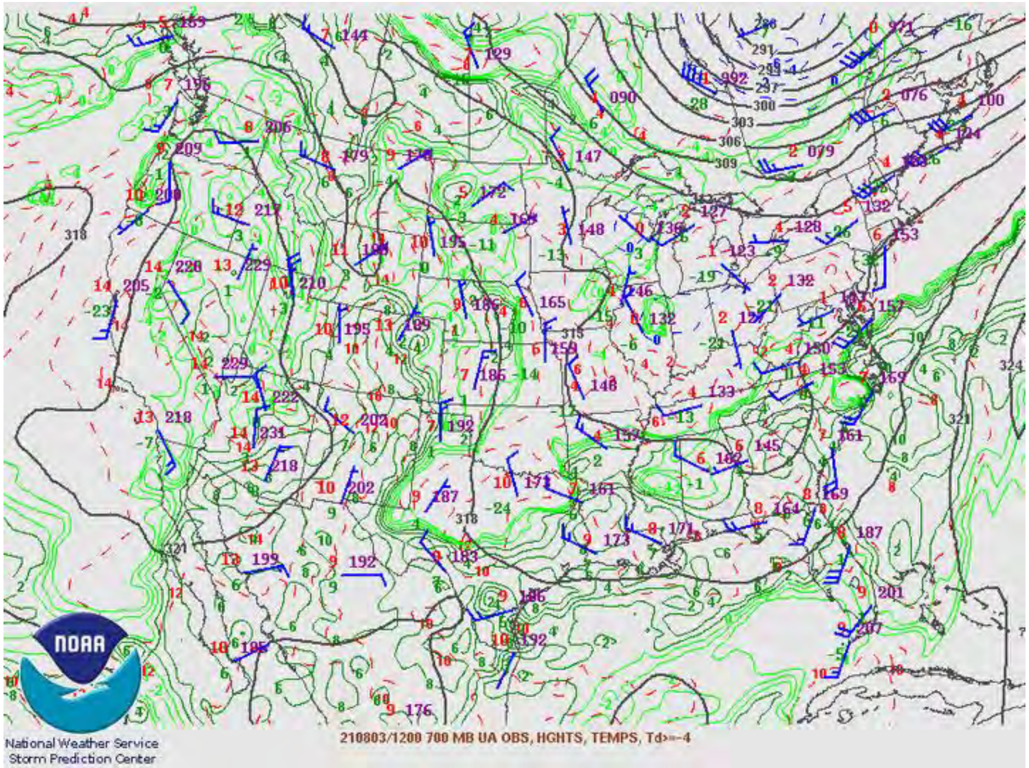

Figure 83. 700-mb map valid at 12:00 UTC (04:00 PST) on August 3, 2021. Upper-level high pressure over Nevada aided widespread transport of smoke into Clark County, NV.

4.4.4 Surface Impacts

The presence of wildfire smoke during the exclusion dates is evident by comparing the visibility conditions prior to the exclusion dates, on the evening of August 1 (Figure 84), to the exclusion dates of August 2-3 (Figure 85 and Figure 86). Local and regional smoke from the three fires identified in Section 4.4.2 is visible in Clark County on both August 2 and 3 at 16:00 LST (16:00 PST), which is a time of day when the photochemical production of ozone typically declines. Local and regional smoke is an atypical influence on ozone and ozone precursors in the Clark County area and, in this case, caused atypical ozone concentrations on the exclusion dates. Smoke was also identified in the KLAS (Las Vegas) METAR report (reported as “FU,” meaning smoke)[12] on August 3, 2021, confirming that smoke was observed at the surface in Clark County.

[12] Available from Iowa Environmental Mesonet, accessed Sept 6, 2023. https://mesonet.agron.iastate.edu/request/download.phtml?network=NV_ASOS

Figure 84. Camera images showing the north (top left), south (bottom left), northeast (top right), and northwest (bottom right) coordinal directions taken from the M Resort Hotel in Clark County, NV, on August 1 at 16:00 LST.

August 02, 2021, 16:00 LST

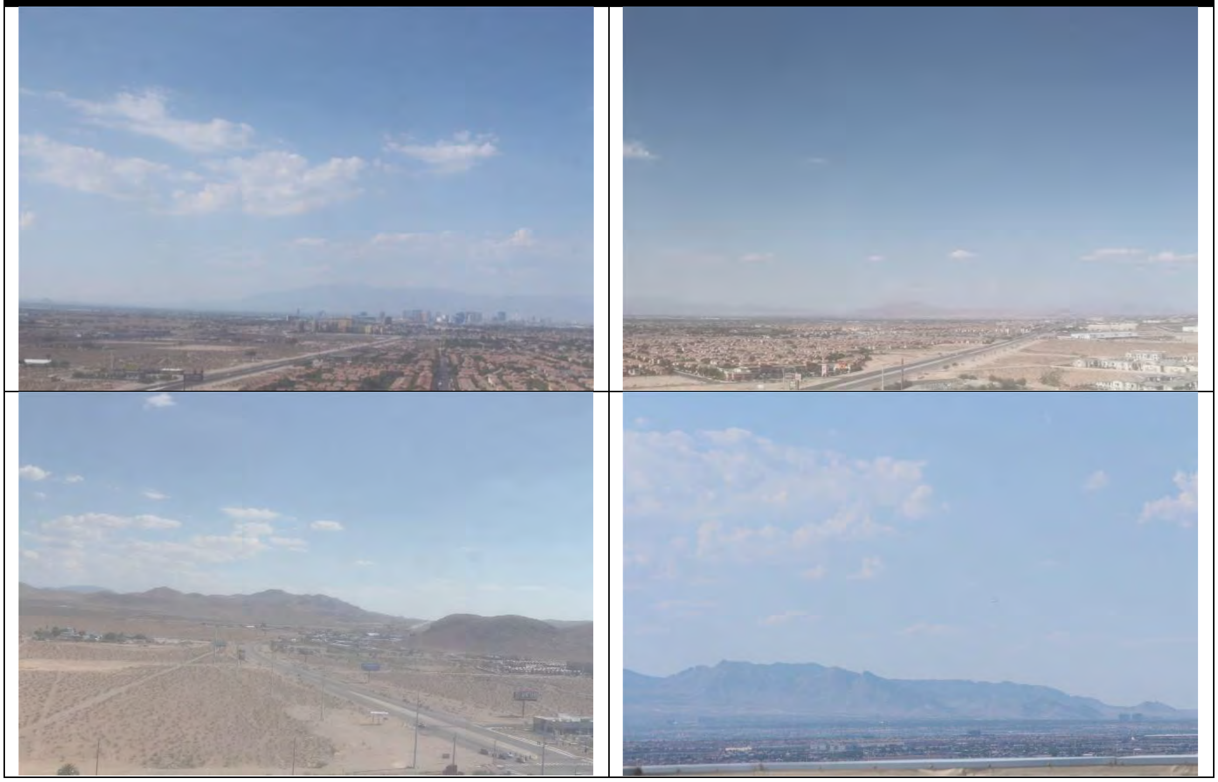

Figure 85. Camera images showing the north (top left), south (bottom left), northeast (top right), and northwest (bottom right) coordinal directions taken from the M Resort Hotel in Clark County, NV, on August 2 at 16:00 LST.

August 03, 2021, 16:00 LST

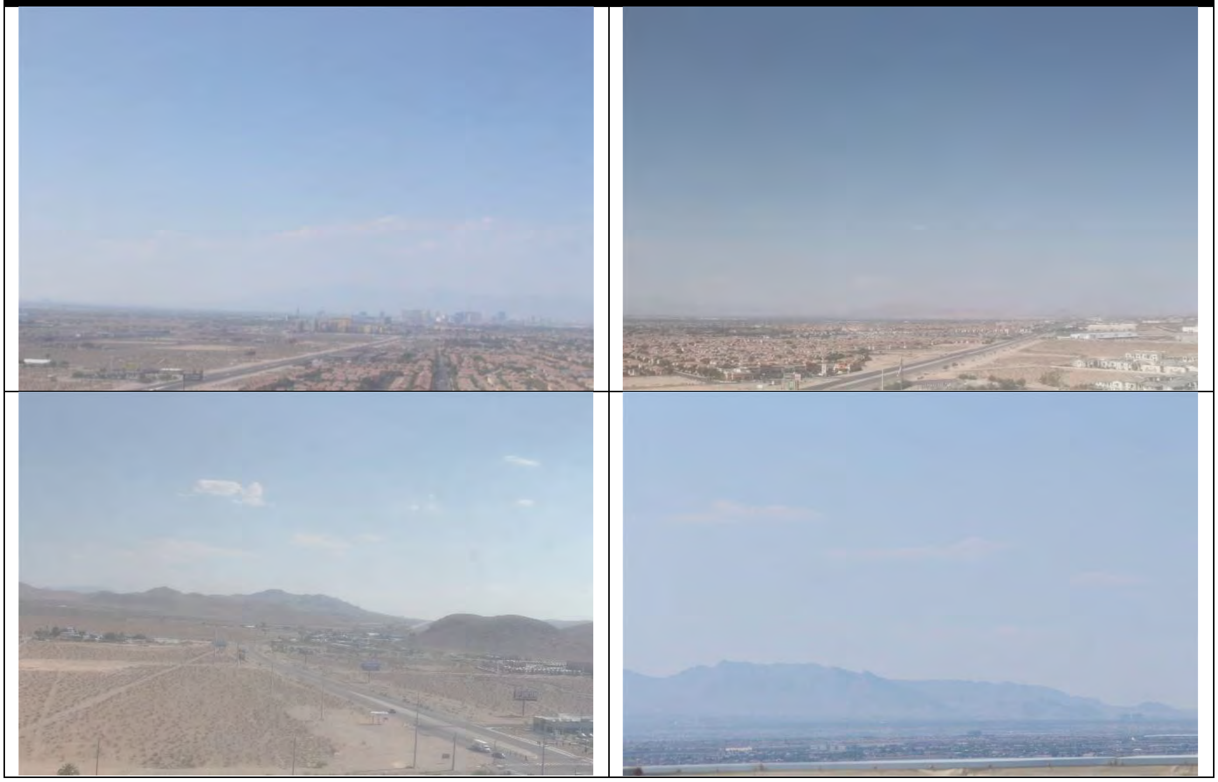

Figure 86. Camera images showing the north (top left), south (bottom left), northeast (top right), and northwest (bottom right) coordinal directions taken from the M Resort Hotel in Clark County, NV, on August 3 at 16:00 LST.

The presence of surface-level smoke in Clark County during the exclusion period is also indicated by enhanced $PM_{2.5}$ and CO concentrations. Figure 87 and Figure 88 show that $PM_{2.5}$ and CO concentrations steadily increased in the region between August 1 and August 3. The shaded area in the figures compares measurements to the diurnal 10th-90th percentile range, which is calculated across five years of data (2017-2021) collected during the ozone season (May – October). At the Green Valley site, $PM_{2.5}$ concentrations showed a peak on the evening of August 2, exceeding the diurnal 90th percentile concentration at 20:00 PST (dashed line in figures). Local maxima $PM_{2.5}$ concentrations also occurred concurrently at the Jerome Mack, Joe Neal, and Walnut Community Center sites. $PM_{2.5}$ concentrations continued to rise in the region and met or exceeded the diurnal 90th percentile concentration at each site on August 3.

CO concentrations at the Green Valley site exceeded the diurnal 90th percentile concentration at the same time that $PM_{2.5}$ concentrations peaked on the evening of August 2 (Figure 88). The combined enhancement of $PM_{2.5}$ and CO concentrations supports the presence of wildfire smoke in the region during the exclusion period. Time series of hourly NO_2 measurements are shown in Figure 89, which show the strongest evidence of enhancement the morning of August 3.

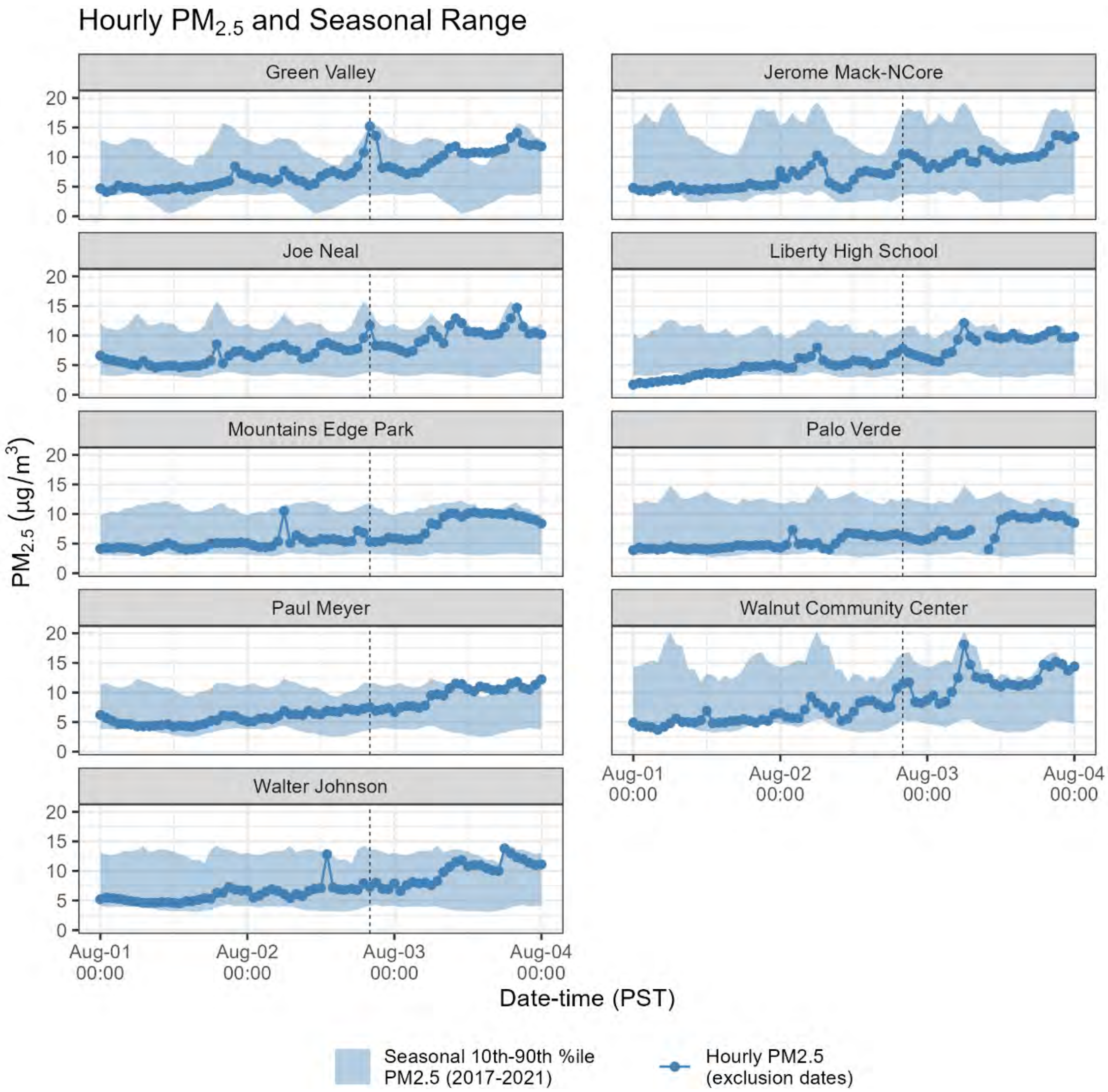

Figure 87. Hourly $PM_{2.5}$ measurements overlaid on the 10th-90th percentile diurnal concentration at affected sites. The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021. The dashed line is August 2, 2021, at 20:00 PST.

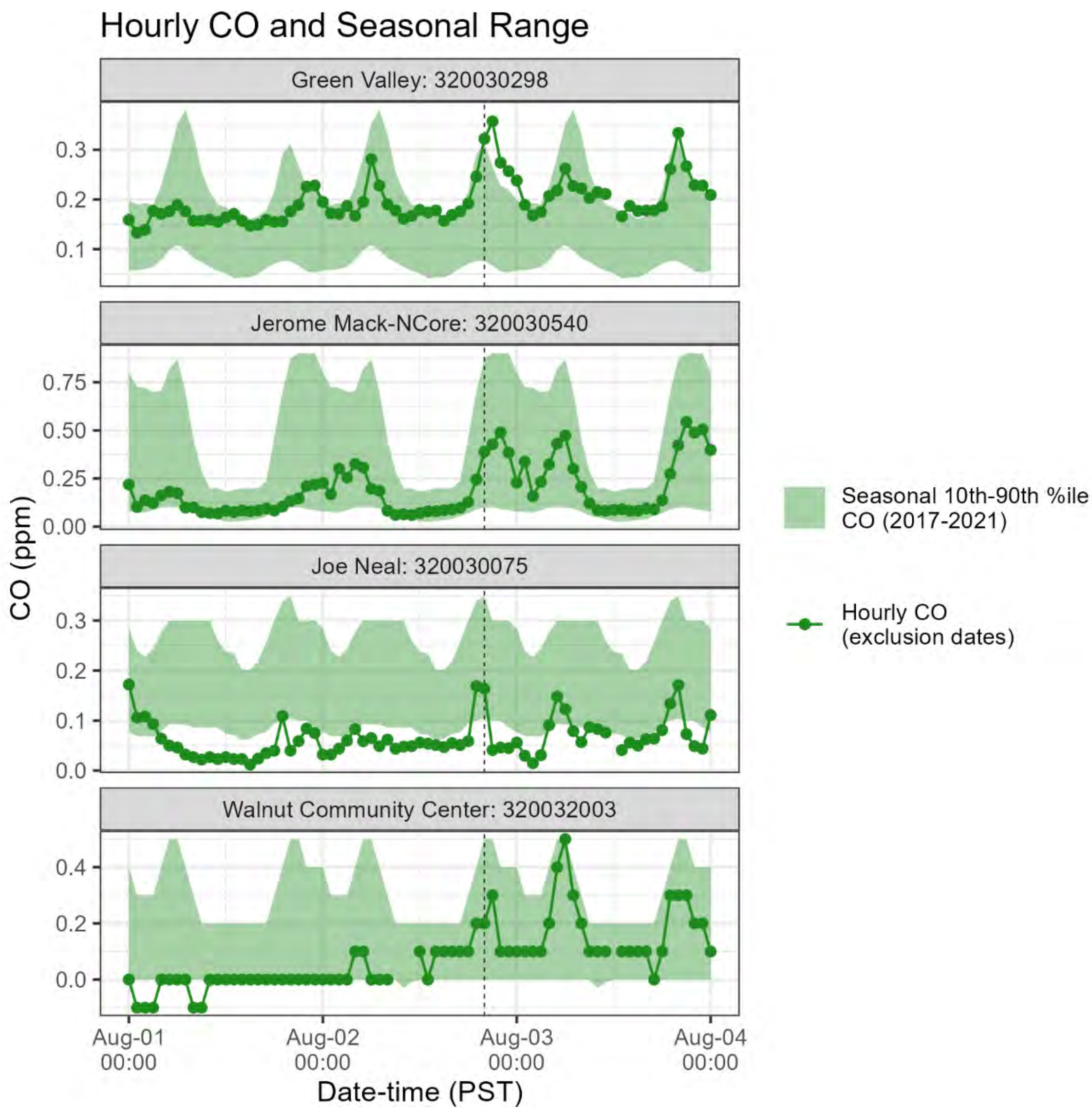

Figure 88. Hourly CO measurements overlaid on the 10th-90th percentile diurnal concentration at affected sites. The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021. The dashed line is August 2, 2021, at 20:00 PST.

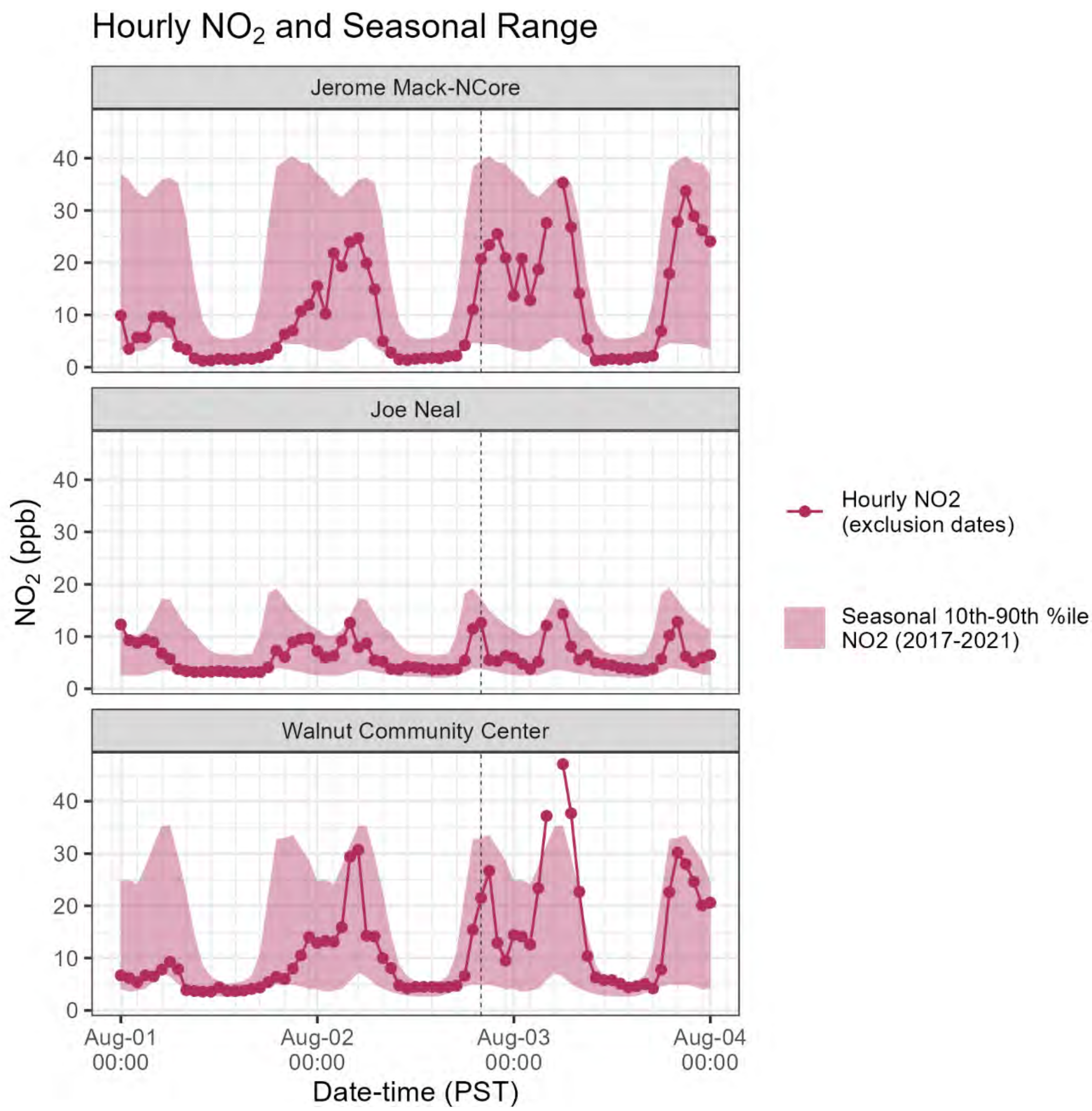

Figure 89. Hourly NO_2 measurements overlaid on the 10th-90th percentile diurnal concentration at affected sites. The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021. The dashed line is August 2, 2021, at 20:00 PST.

The ratio of $PM_{2.5}$-to-PM_{10} concentrations was also examined to determine if wildfire smoke entered Clark County on or before the exclusion dates. Increases in this ratio are indicative of wildfire smoke. Figure 90 shows a time series of the $PM_{2.5}$-to-PM_{10} ratio from August 1-5 at the affected monitoring sites compared to the ozone season mean and 5th-95th percentile range for available data between 2017-2021. All sites show above average ratios starting late in the day on August 2 and continuing through the early morning of August 3. The same diurnal pattern persists during the day on August 3 and August 4. This observation coincides with the $PM_{2.5}$ and CO enhancements that occurred on August 2 and 3, suggesting that wildfire smoke entered the area on August 2 and lingered through August 4, and contributed to the atypical ozone event that occurred on August 2 and 3.

Figure 90. Ratio of $PM_{2.5}$-to-PM_{10} concentrations at affected sites, before and during the August 2 and 3 event period. The 5-yr* average $PM_{2.5}$-to-PM_{10} diurnal ratio is displayed as a dotted line, and the 5th-95th percentile range is shown as a shaded ribbon. The 5th-95th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021. *Sites where data collection began after 2017 are indicated.

4.4.5 Event Statistics

Table 18 summarizes the daily measurements of ozone, $PM_{2.5}$, CO, and NO_2 on the exclusion day, as well as the percentile rank of the observation compared to the previous five years of data (2017-2021). Ozone MDA8 measurements ranged from the 96th-99.5th percentile at most sites on both days. The 24-hr average $PM_{2.5}$ concentrations ranged from near the 50th-75th percentile on August 2, and from the 75th-90th percentile on August 3. A regional pattern of enhanced 1-hr daily maximum CO concentrations was not observed; however, some sites, such as Green Valley, showed local CO concentration enhancements. The 1-hr daily maximum of NO_2 concentration was similarly sensitive to location, with maximums observed on August 3 ranging from the 47th-98th percentiles.

Table 18. Percentile of pollutant measurements on the exclusion day compared with most recent five years* (2017-2021). The percentile rank is calculated across the ozone production season (May 1-October 31) of 2017-2021.

Date	Site Name	Site Code	Ozone		$PM_{2.5}$		CO		NO_2	
			Ozone MDA8 (ppb)	Percent Rank	PM2.5 24-hr Avg (µg/m3)	Percent Rank	CO 1-hr Daily Max (ppb)	Percent Rank	NO2 1-hr Daily Max (ppb)	Percent Rank
8/2/2021	Green Valley	320030298	74	98.7	7.6	74.4	357	77.9*	--	--
	Jerome Mack-NCore	320030540	72	98.5	7.6	59.1	489	44.5	25.5	34.5
	Joe Neal	320030075	75	97.8	7.8	74.5*	169	12.6*	12.6	35.9
	Liberty High School	320030299	77	99.5*	5.8	47.8*	--	--	--	--
	Mountains Edge Park	320030044	75	98.6*	5.6	48.4*	--	--	--	--
	Palo Verde	320030073	78	99.8	5.7	53.6*	--	--	--	--
	Paul Meyer	320030043	69	92.1	6.5	60.7	--	--	--	--
	Walnut Comm. Center	320032003	78	98.7*	7.7	47.1*	300	32.7*	30.7	57.5*
	Walter Johnson	320030071	77	98.7	6.9	57.9*	--	--	--	--
8/3/2021	Green Valley	320030298	72	97.2	10.3	90.2	334	71.2*	--	--
	Jerome Mack-NCore	320030540	64	90.3	10.2	79.1	544	50.9	35.3	58.7
	Joe Neal	320030075	73	96.6	10.3	85.3*	171	13.3*	14.3	47.4
	Liberty High School	320030299	76	98.9*	9.1	83.7*	--	--	--	--
	Mountains Edge Park	320030044	80	99.5*	8.7	80.5*	--	--	--	--
	Palo Verde	320030073	75	99.1	8	76.7*	--	--	--	--
	Paul Meyer	320030043	77	99.2	9.8	87.8	--	--	--	--
	Walnut Comm. Center	320032003	68	92.8*	12.1	85*	500	60.8*	47.1	98*
	Walter Johnson	320030071	74	96.7	10.1	82*	--	--	--	--

4.5 August 7, 2021

4.5.1 Event Summary

The unrepresentative ozone event took place on August 7, 2021, and affected twelve sites in Clark County, NV. Time series graphs showing hourly ozone concentrations that exceeded the seasonal means (calculated using May 1-October 31, 2017-2021) and 10th-90th percentiles at each site are shown in Figure 91.

On August 7, hourly ozone concentrations at most sites exceeded the 90th percentile between 08:00 to 19:00 PST and returned to near-mean concentrations overnight. The MDA8 ozone concentrations at the affected sites ranged from 73-87 ppb. Eight of the 12 sites had MDA8 ozone concentrations above 80 ppb, including the Indian Springs (87 ppb) and Green Valley (84 ppb) sites. The bottom of the range of concentrations occurred at the Jean and Virgin Valley High School (73 ppb at both), Jerome Mack-NCore (76 ppb), and Walnut Community Center (79 ppb) sites.

An abundance of regional wildfire smoke was identified as a major contributor to this event, particularly from the Dixie, Monument, Haypress River Complex, and Antelope Fires in California. Evidence of surface level wildfire smoke during the exclusion day includes (1) HYSPLIT dispersion modeling indicating the presence of smoke accumulation in Clark County, (2) remote sensing imagery and HMS smoke boundaries showing smoke over Clark County, (3) a drastic reduction in visibility based on camera images, and (4) enhanced ground-level concentrations greater than the seasonal 90th percentile simultaneously for $PM_{2.5}$, CO, and NO_2, and $PM_{2.5}$-to-PM_{10} ratios that aligned with ozone enhancement. This combination of evidence strongly indicates that this is an unrepresentative event for assessing base and future ozone design values.

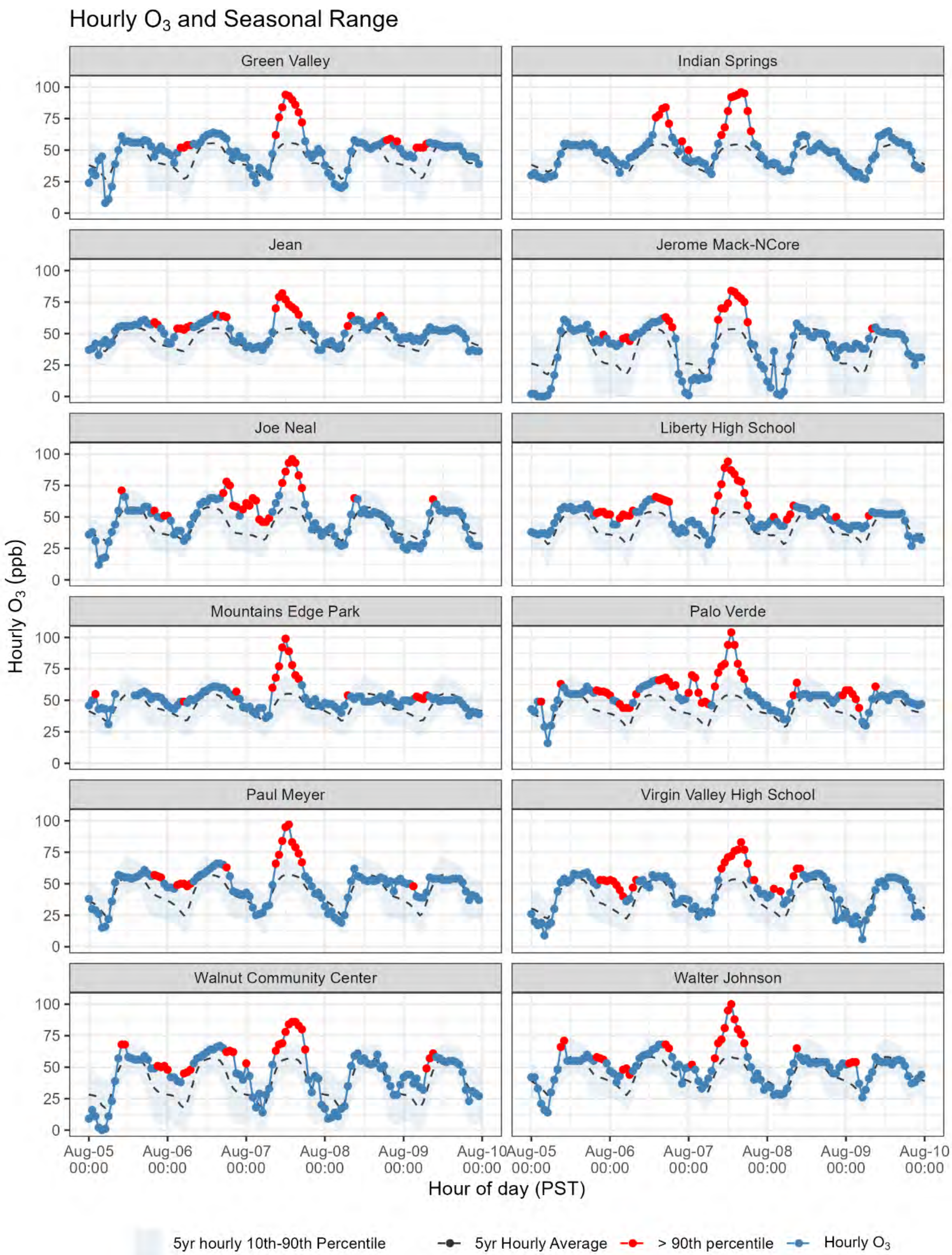

Figure 91. Hourly ozone concentrations (ppb) compared to 5-yr* ozone season (May 1-October 31) hourly means and 10-90th percentiles. *Note: data collection began in 2020 at the Mountains Edge Park site, and in 2021 at the Liberty High School, Virgin Valley High School, and Walnut Community Center sites.

4.5.2 Identification of Wildfires

Numerous wildfires throughout the western U.S. were active on August 7, 2021, the exclusion day, and contributed to widespread regional smoke. Four major wildfires with significant smoke emissions contributed to regional smoke: the Dixie, Monument, Haypress River Complex and Antelope Fires in California (**Figure 92**). Regional smoke was present during early August 2021 throughout the northwest/western U.S., and this was verified for the days of August 5-7 through visualization of smoke and wildfire detection geodata provided by the NOAA HMS (**Figure 93**). **Table 19** presents the state location, total acres within the fire perimeter, actively burning acres on the exclusion day, and the start and containment dates for each fire based on data from the WFGIS Current Interagency Fire Perimeters and the Satellite Fire Occurrence and Growth database.[13]

[13] McClure et al. (2023) Consistent, high-accuracy mapping of daily and sub-daily wildfire growth with satellite observations. International Journal of Wildland Fire 32, 694-708. Available at **https://www.publish.csiro.au/wf/ExportCitation/WF22048**.

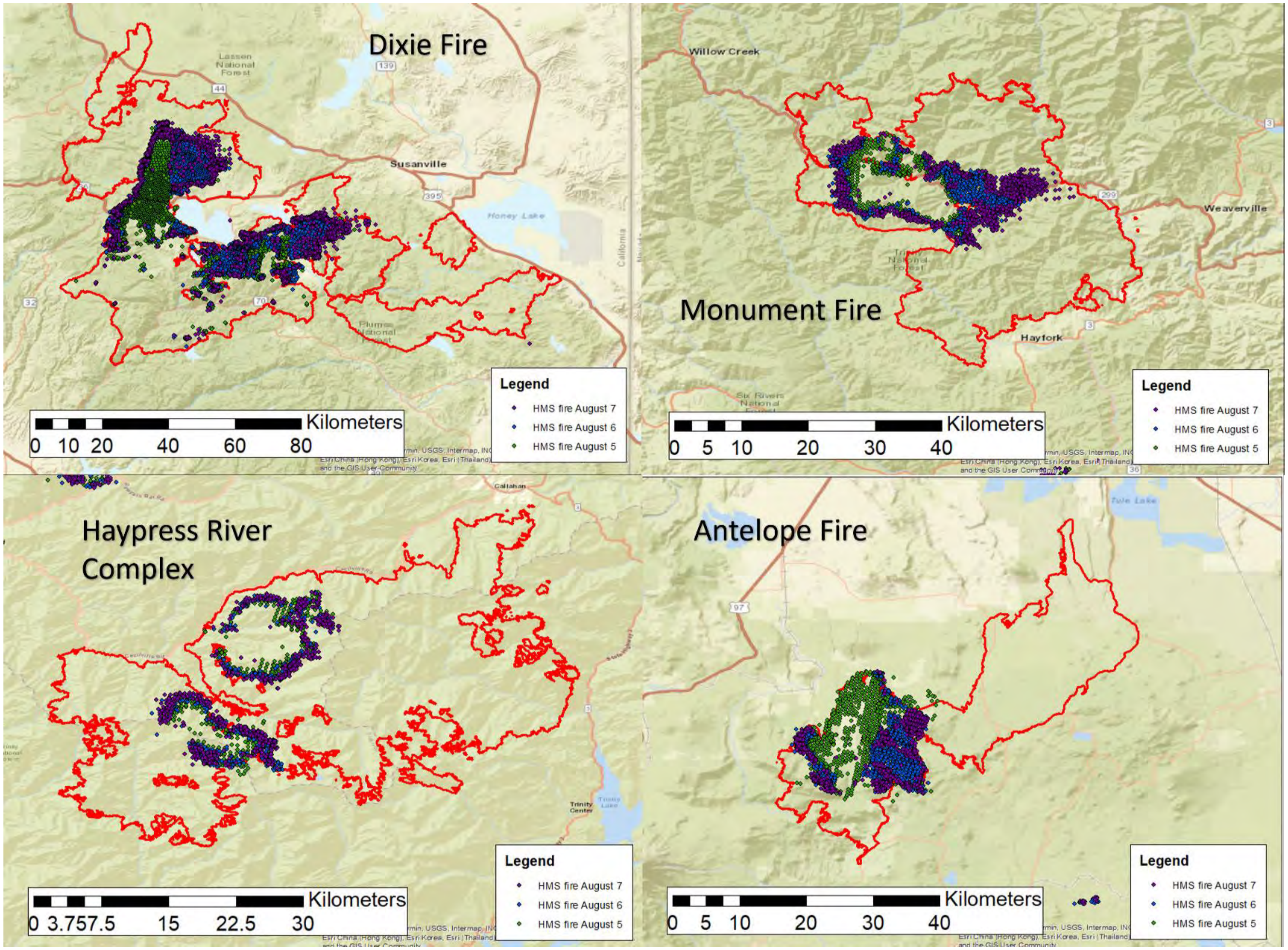

Figure 92. Final fire perimeters (red) and HMS fire detections for the Dixie, Monument, Haypress River Complex, and Antelope Fires during August 5-7, 2021.

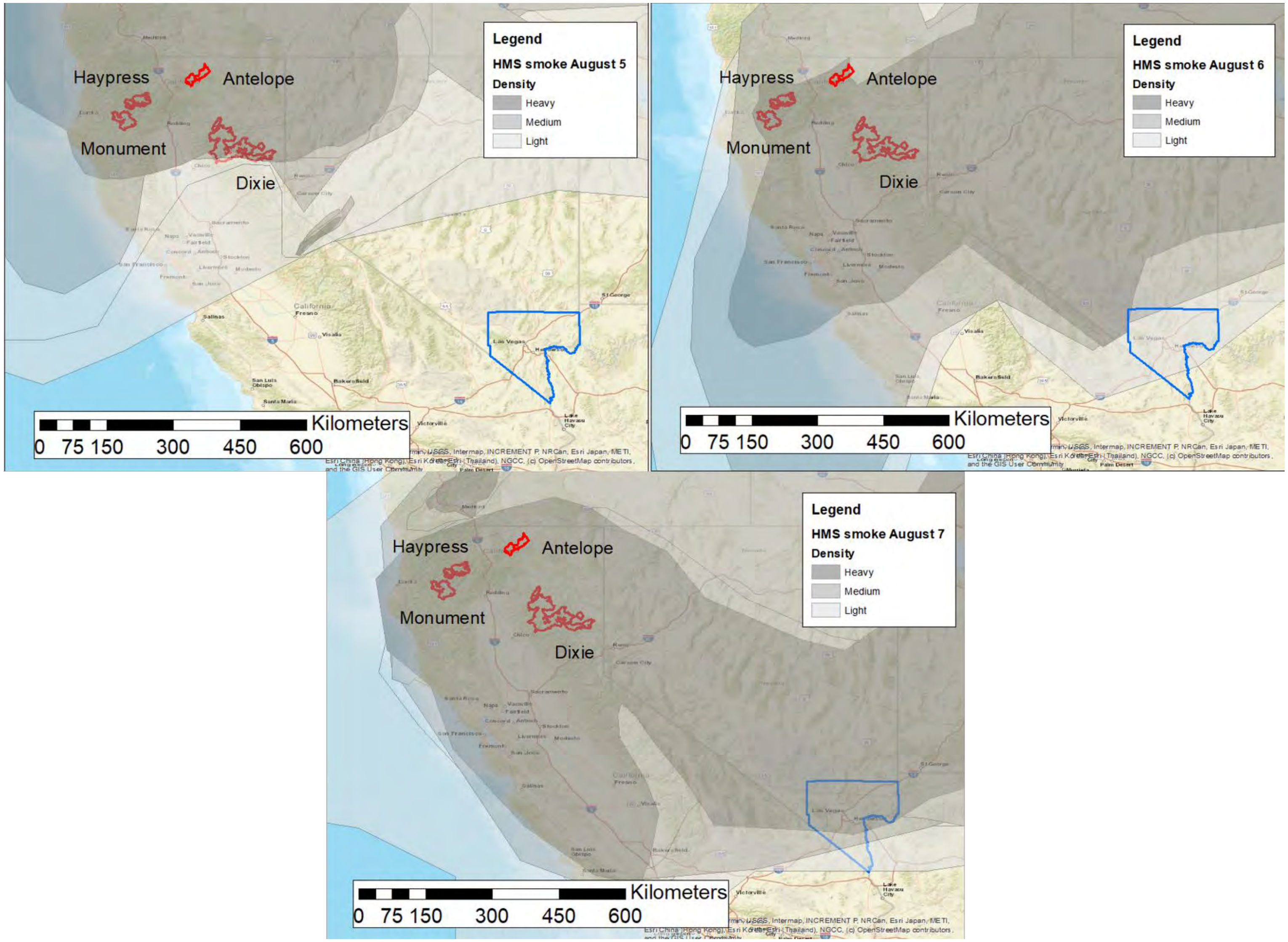

Figure 93. HMS smoke data for August 5-7, 2021, included with qualitative smoke density. Fire perimeters from the major fires contributing to the exclusion date are shown in red and the Clark County, NV, boundary is shown in blue.

Table 19. Wildfires affecting Clark County on the exclusion day.

Wildfire Name	State	Total Acres	Active Acres August 7	Start Date	Containment Date
Dixie	California	963,405	48,129	July 14	October 15
Monument	California	223,124	19,480	July 31	October 20
Haypress River Complex	California	199,343	12,103	July 31	October 25
Antelope	California	145,632	12,341	August 1	October 14

4.5.3 Dispersion Modeling and Regional Analysis

HYSPLIT dispersion modeling was performed for August 5-7, 2021. Dispersion was initiated at 16:00 PST from the four identified active fires that impacted the exclusion date. GDAS 1.0° data horizontal resolution was used for meteorological input. Output from the dispersion modeling was integrated over a 24-hr period, from August 6 at 16:00 PST through August 7 at 16:00 PST. 16:00 PST on August 6, the day before the exclusion date, was chosen to correspond with the initial increase of observed $PM_{2.5}$ concentrations in Clark County. The accumulation of smoke at 0-100 m for the 24-hr period is shown in Figure 94.

The results of the HYSPLIT dispersion modeling show that smoke from multiple California wildfires accumulated to produce a dense layer of widespread smoke that covered much of California and Nevada, including Clark County. The dispersion modeling results are consistent with the HMS smoke plume data (shown in gray in Figure 94); HMS is an independent smoke identification database. The dispersion modeling results show smoke from multiple California wildfires reached Clark County, Nevada, on August 7, 2021, and the smoke was present in the lower mixed layer, impacting the surface conditions.

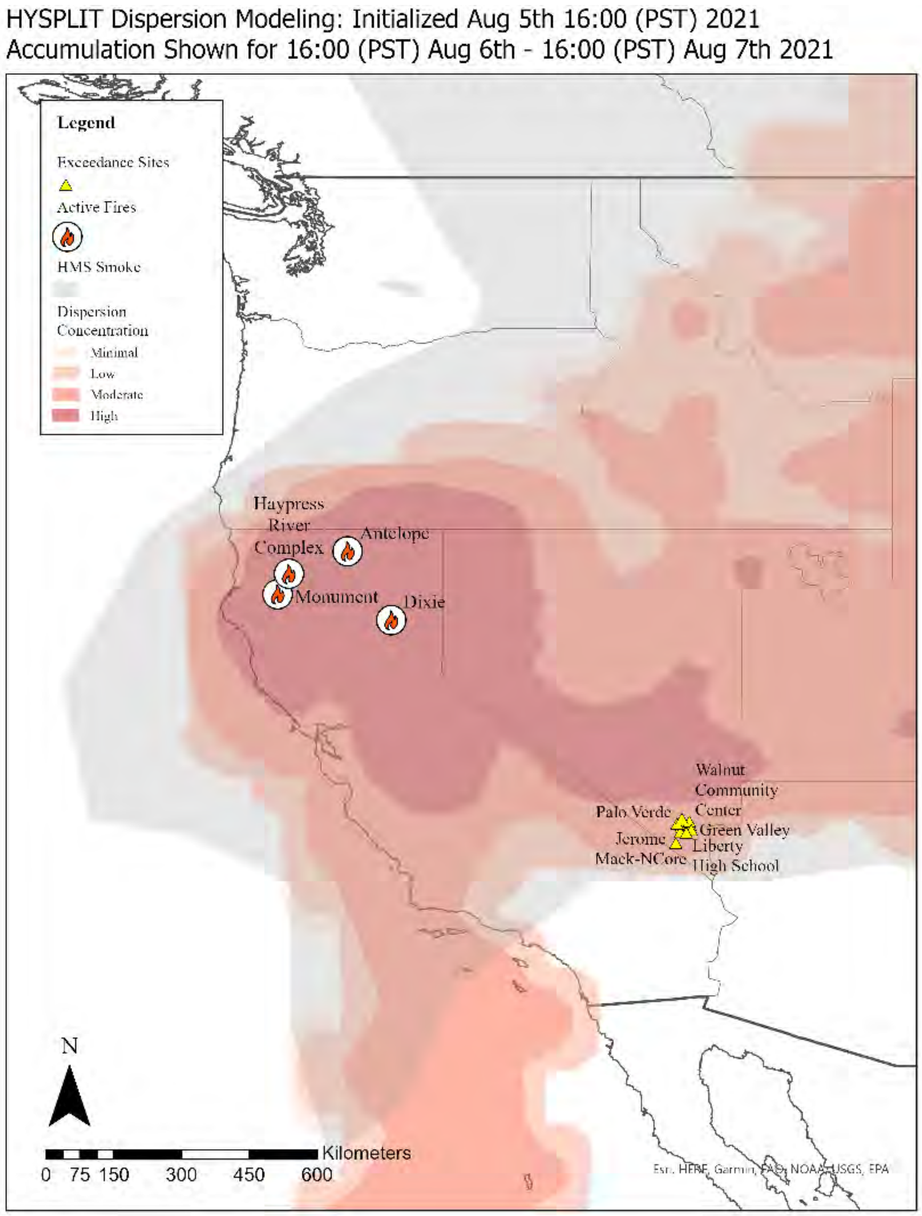

Figure 94. HYSPLIT dispersion modeling for four large fires (labeled as "Active Fires") throughout the western U.S. GDAS 1.0° meteorological data was used, and dispersion was initiated on August 5, 2021, at 16:00 PST to model the regional smoke observed in satellite and HMS products. HMS smoke is shown in gray and qualitative concentrations of particulate matter are shown in shades of red. Accumulation of particulate matter is shown at 0-100 m for 16:00 PST on August 6 through 16:00 PST on August 7, 2021.

Remote sensing data from MODIS Terra visible satellite imagery confirms the large extent of regional smoke from the California fires and is consistent with the dispersion modeling results for August 7. Figure 95 shows regional smoke from the California fires extending below the Central Valley in California into southern Nevada, and directly affecting Clark County, NV.

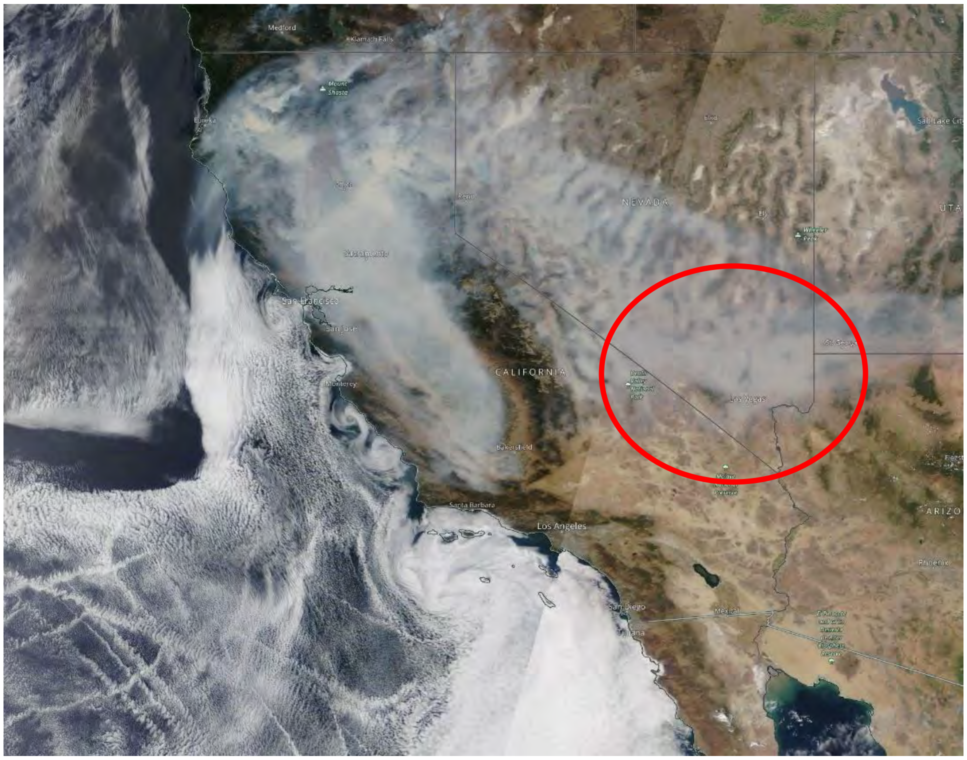

Figure 95. MODIS Terra satellite image valid on August 7, 2021. Smoke from California wildfires is visible across central and southern Nevada. This smoke contributed to poor air quality and reduced visibility in Clark County. The red circle shows the area of smoke over Clark County.

4.5.4 Surface Impacts

Figure 96 and Figure 97 compare visibility conditions in the Las Vegas Valley before and during the exclusion date. Figure 96 shows visibility conditions at 13:00 LST (13:00 PST) on August 6, the day before the event. Figure 97 shows visibility conditions at 13:00 LST on August 7, the exclusion date, and the presence of thick, regional wildfire smoke from the fires identified in Section 4.5.2. Regional smoke from wildfires strongly influenced air quality including ozone and ozone precursors in the Clark County area and caused atypical ozone concentrations on the exclusion date.

August 06, 2021, 13:00 LST

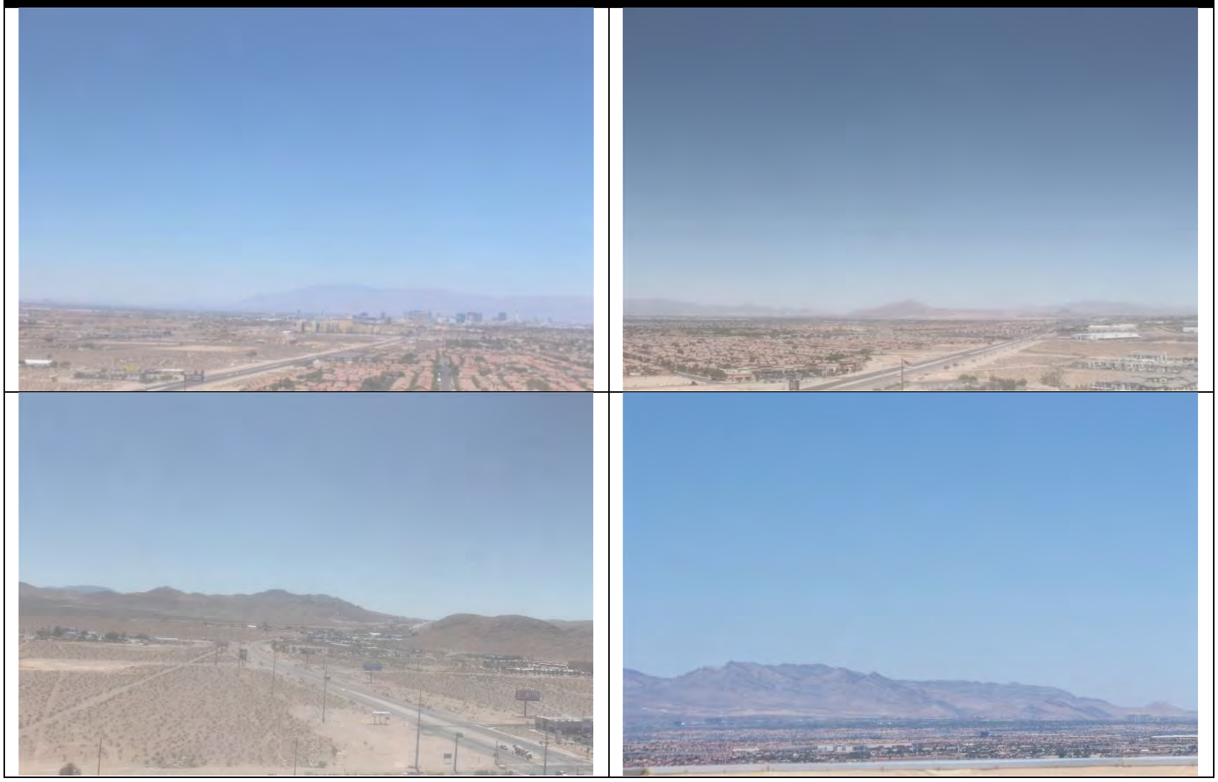

Figure 96. Camera images showing the north (top left), south (bottom left), northeast (top right), and northwest (bottom right) coordinal directions, taken from the M Resort Hotel in Clark County, NV, on August 6, 2021, at 13:00 LST.

Figure 97. Camera images showing the north (top left), south (bottom left), northeast (top right), and northwest (bottom right) coordinal directions taken from the M Resort Hotel in Clark County, NV, on August 7, 2021, at 13:00 LST.

The presence of surface level wildfire smoke on August 7 is strongly corroborated by enhanced ground-level $PM_{2.5}$, CO, and NO_2 concentrations during the same time period. Hourly $PM_{2.5}$ concentrations exceeded 200 μg/m^3 in Clark County on August 7, and far-exceeded the diurnal 90th percentile for $PM_{2.5}$ concentrations at all sites that exceeded the MDA8 ozone NAAQS threshold. $PM_{2.5}$ concentrations compared to the diurnal 10th-90th percentile $PM_{2.5}$ concentration, calculated from 2017-2021, shown in Figure 98.

Hourly CO concentrations are shown alongside the 10th-90th percentile diurnal concentration, calculated from 2017-2021 at affected sites (Figure 99). CO concentrations exceeded the 90th percentile concentration at each site during the late morning and afternoon of August 7. Concurrently, NO_2 concentrations in Clark County were elevated and above the 90th percentile diurnal concentration (Figure 100).

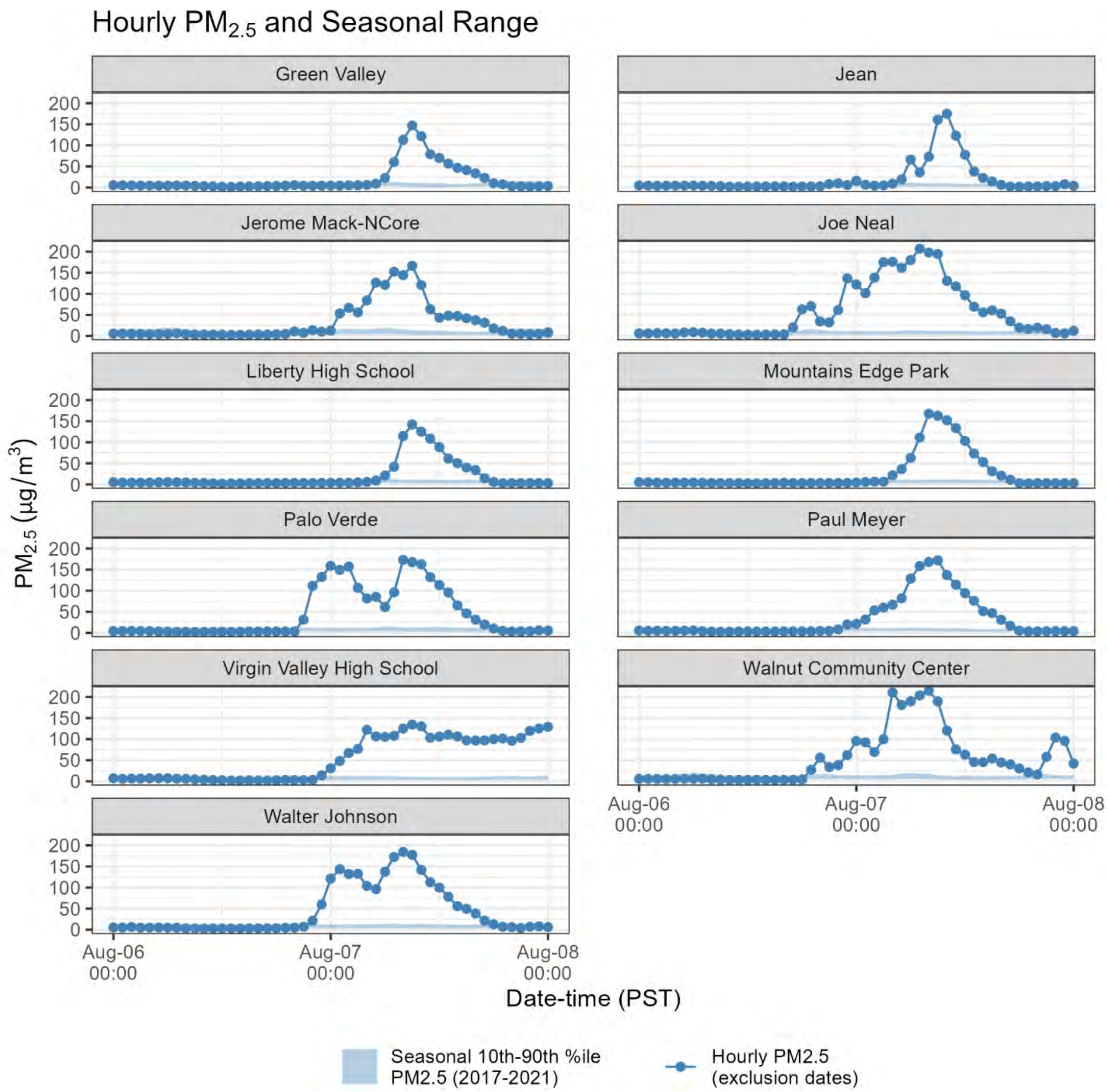

Figure 98. Hourly $PM_{2.5}$ measurements overlaid on the 10th-90th percentile diurnal concentration at affected sites that measure $PM_{2.5}$. The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021.

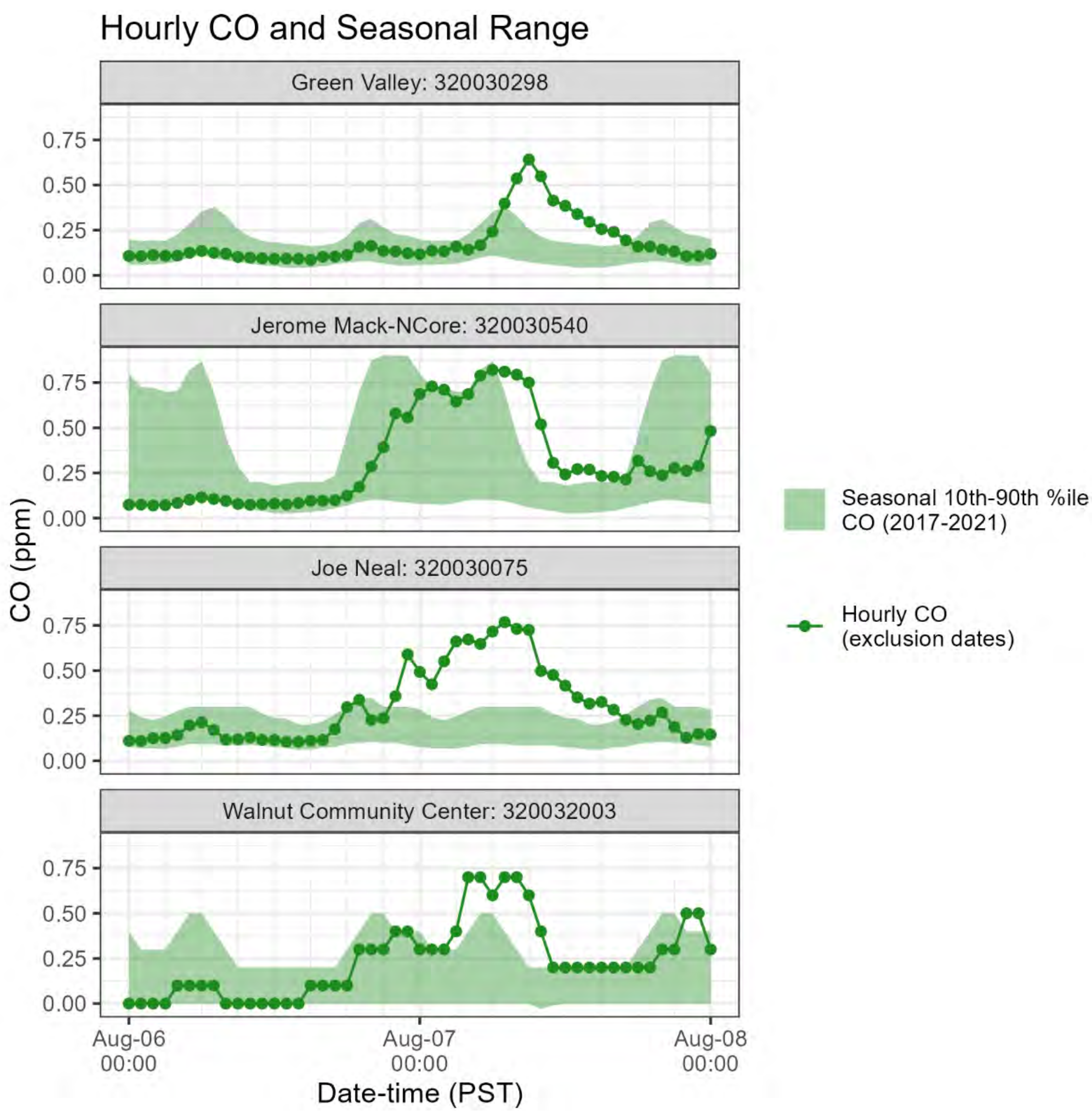

Figure 99. Hourly CO measurements overlaid on the 10th-90th percentile diurnal concentration at affected sites that measure CO. The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021.

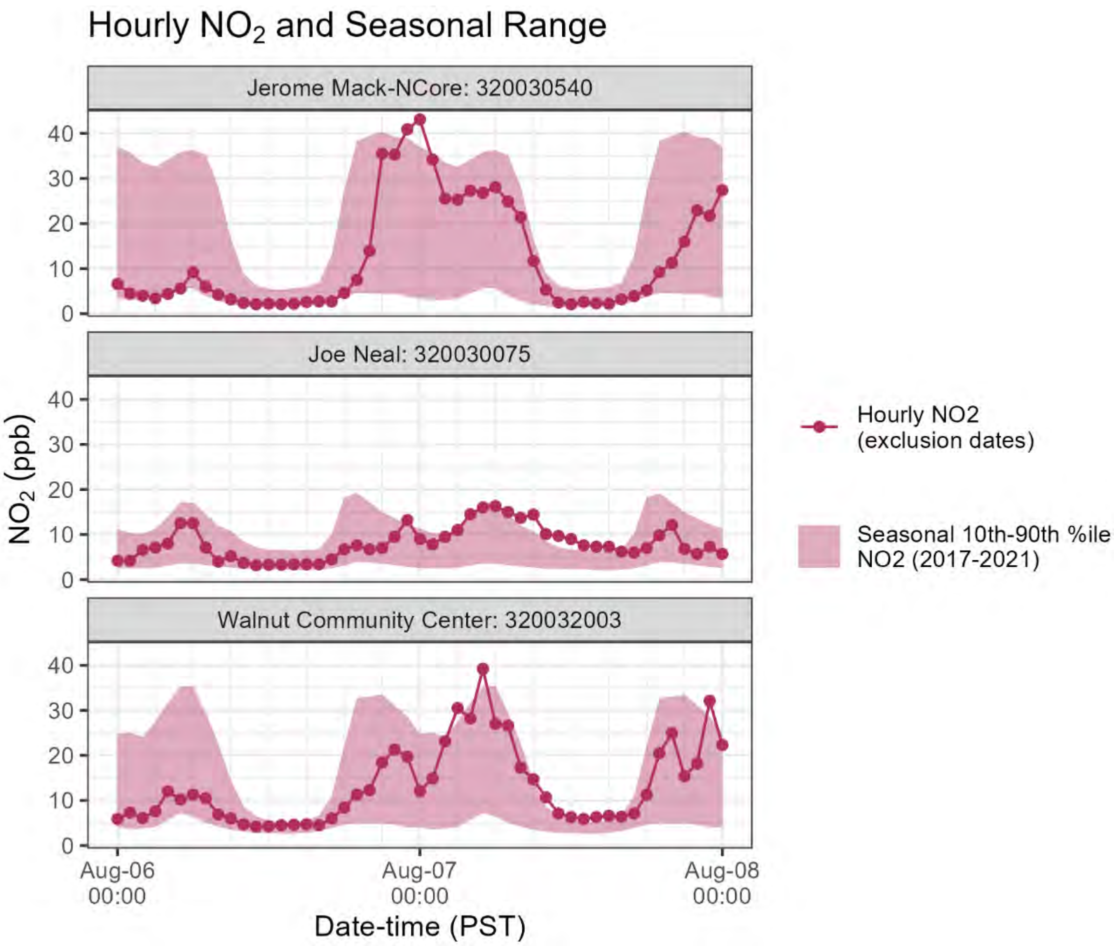

Figure 100. Hourly NO_2 measurements overlaid on the 10th-90th percentile diurnal concentration at affected sites that measure NO_2. The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021.

The ratio of $PM_{2.5}$-to-PM_{10} concentrations was also examined to determine if wildfire smoke entered Clark County on or before the exclusion dates. Increases in this ratio are indicative of wildfire smoke. Figure 101 and Figure 102 show time series of the $PM_{2.5}$-to-PM_{10} ratio from August 6 through August 8, the 5-yr average ratio, compared to the ozone season mean and 5th-95th percentile range for available data between 2017-2021. $PM_{2.5}$-to-PM_{10} ratios at all affected (Figure 101) and non-affected sites (Figure 102) were generally below average on August 6, then reached or exceeded the 95th percentile during the morning and daytime on August 7. Ratios at all sites spiked to reach or exceed the 95th percentile again the following day (August 8). These observations provide evidence that wildfire smoke containing enhanced $PM_{2.5}$-to-PM_{10} ratios entered Clark County on August 7, immediately prior to and during the atypical ozone event on August 7.

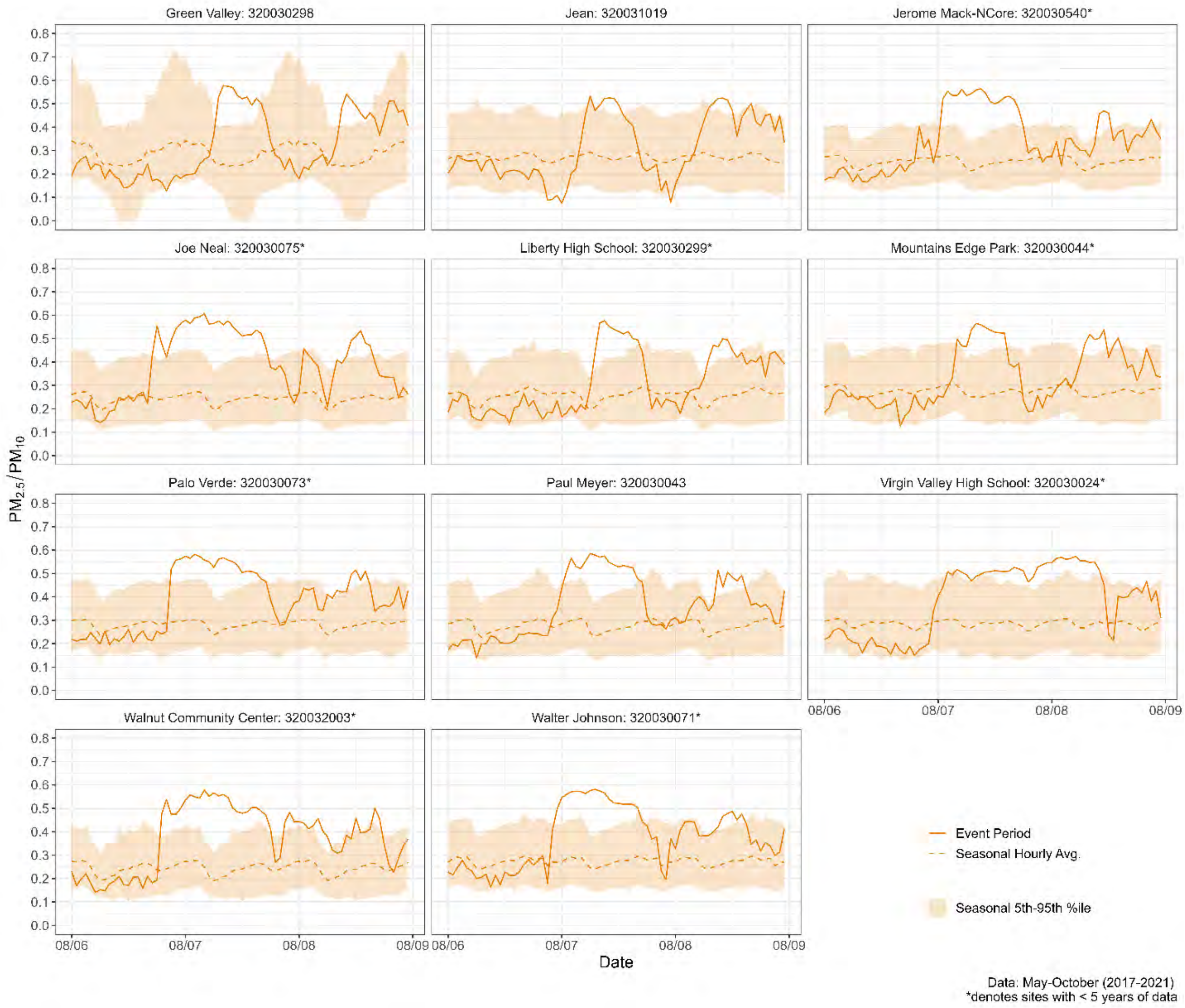

Figure 101. Ratio of $PM_{2.5}$-to-PM_{10} concentrations at all affected sites during the August 7 event period. The 5-yr average $PM_{2.5}$-to-PM_{10} diurnal ratio is displayed as a dotted line, and the 5th-95th percentile range is shown as a shaded ribbon. The 5th-95th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021.

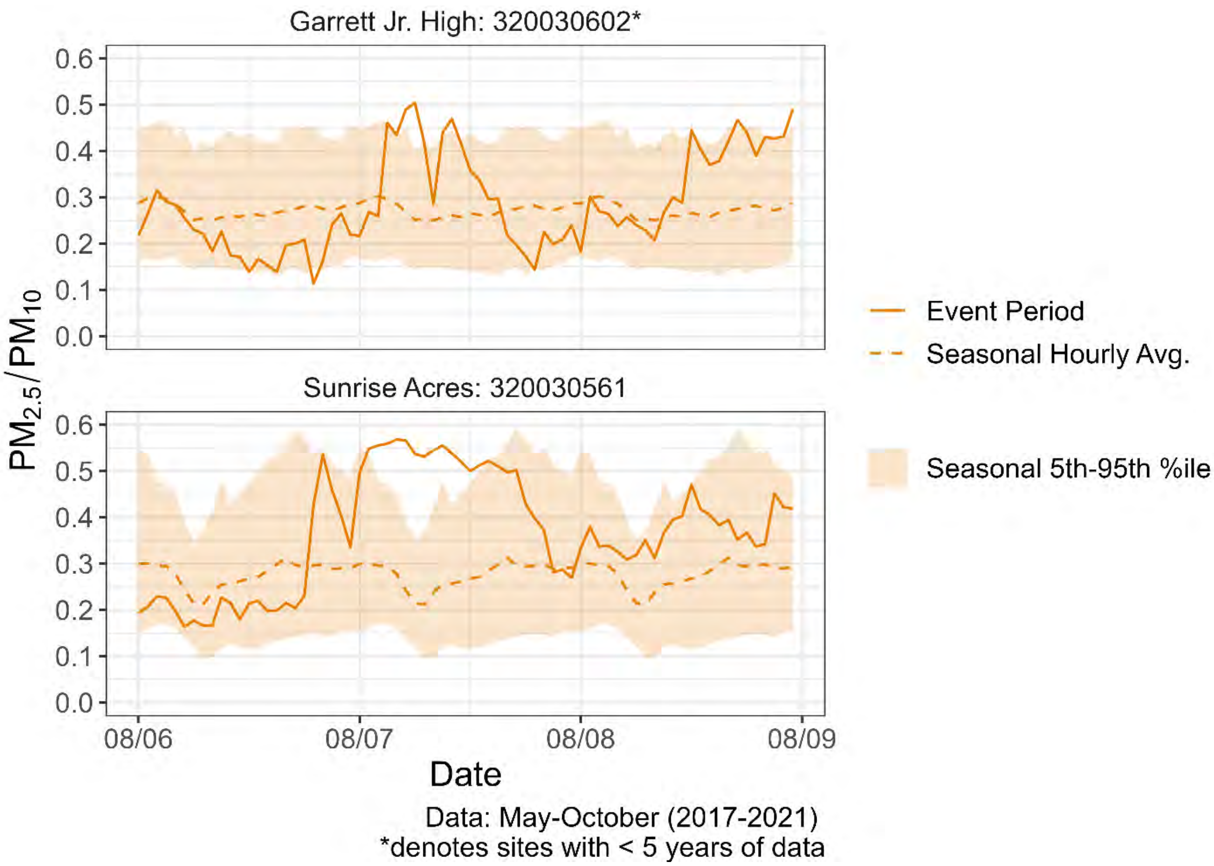

Figure 102. Ratio of $PM_{2.5}$-to-PM_{10} concentrations at all non-affected sites during the August 7 event period. The 5-yr average $PM_{2.5}$-to-PM_{10} diurnal ratio is displayed as a dotted line, and the 5th-95th percentile range is shown as a shaded ribbon. The 5th-95th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021.

The Las Vegas airport (KLAS) hourly METAR reports for August 7, 2021, also notes that smoke was present for 14 hours (Table 20). The METAR report additionally indicates that visibility was significantly impacted on this day due to smoke intrusion. Wind speeds were low (0-5 knots) at KLAS during this time, resulting in stagnant conditions favorable to smoke-influenced ozone production.

Table 20. Hourly METAR ASOS reports from KLAS for August 7, 2021. Smoke from denoted by the METAR code FU.

August 7 Time (UTC)	Wind Direction / Speed	Visibility (Sq. Miles)	Sky Condition
23:56	VRB / 05 KT	7	FU (SMOKE)
22:56	230 / 04 KT	6	FU (SMOKE)
21:56	200 / 03 KT	5	FU (SMOKE)
20:56	000 / 00 KT	4	FU (SMOKE)
19:56	000 / 00 KT	4	FU (SMOKE)
18:56	VRB / 06 KT	3	FU (SMOKE)
18:54	060 / 06 KT	3	FU (SMOKE)
17:56	010 / 07 KT	2	FU (SMOKE)
16:59	000 / 00 KT	2	FU (SMOKE)
16:56	070 / 03 KT	2	FU (SMOKE)
15:56	000 / 00 KT	2	FU (SMOKE)
15:03	000 / 00 KT	2 1/2	FU (SMOKE)
14:56	000 / 00 KT	3	FU (SMOKE)
13:56	000 / 00 KT	4	FU (SMOKE)

Additionally, data from the Cloud-Aerosol Lidar and Infrared Pathfinder Satellite Observations (CALIPSO) over Clark County also shows a layer of smoke near the surface [(1-4 km above ground level (AGL)] in the Las Vegas region (Figure 103).

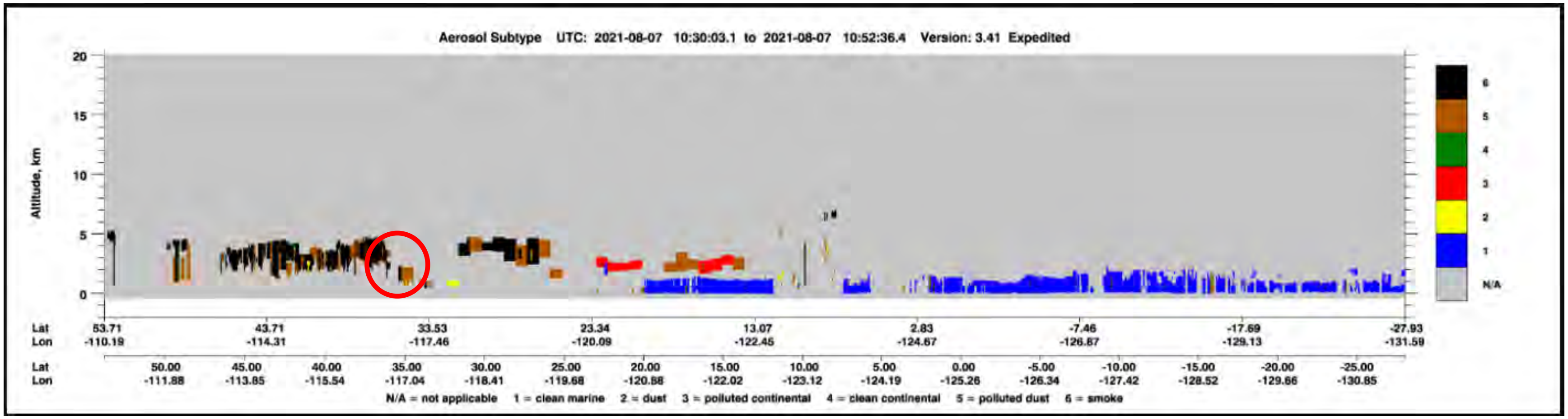

Figure 103. CALIPSO image on August 7, 2021. Black colors are defined as smoke and brown colors as polluted dust. The satellite detected a smoke layer near the Las Vegas region at an elevation of 1-4 km AGL. The red circle indicates Las Vegas (which is centered near 36.2, -115.2), with a smoke layer nearby.

4.5.5 Event Statistics

Table 21 summarizes the daily measurements of ozone, $PM_{2.5}$, CO, and NO_2 concentrations on the exclusion day, as well as the percentile rank of the observation compared to the previous five years of data (2017-2021). On August 7, 2021, ozone MDA8 measurements were the highest recorded in the 5-yr period at eight out of 12 sites, and above the 99th percentile for the remaining four sites. 24-hr average $PM_{2.5}$ concentrations were similarly the highest recorded in the 5-yr period at nine out of 11 sites, and in the 99.9th percentile at the remaining two sites. CO 1-hr daily maximum concentrations ranged from the 74th-100th percentile. NO_2 1-hr daily maximum measurements were also enhanced, ranging from the 59th percentile at Joe Neal to ~85th percentile at the Jerome Mack-NCore and Walnut Community Center sites.

Table 21. Percentile of pollutant measurements on the exclusion day compared with most recent five years* (2017-2021). The percentile rank is calculated across the ozone production season (May 1-October 31) of 2017-2021.

Date	Site Name	Site Code	Ozone		$PM_{2.5}$		CO		NO_2	
			Ozone MDA8 (ppb)	Percent Rank	$PM_{2.5}$ 24-hr Avg ($\mu g/m^3$)	Percent Rank	CO 1-hr Daily Max (ppb)	Percent Rank	NO_2 1-hr Daily Max (ppb)	Percent Rank
8/7/2021	Green Valley	320030298	84	100	36.6	99.9	641	99.3*	--	--
8/7/2021	Indian Springs	320037772	87	100	--	--	--	--	--	--
8/7/2021	Jean	320031019	73	99.2	36.6	99.9	--	--	--	--
8/7/2021	Jerome Mack-NCore	320030540	76	99.7	61.1	100	820	74.6	43.1	84.3
8/7/2021	Joe Neal	320030075	83	100	98.2	100*	768	100*	16.3	59
8/7/2021	Liberty High School	320030299	82	100*	37.2	100*	--	--	--	--
8/7/2021	Mountains Edge Park	320030044	80	99.5*	49.2	100*	--	--	--	--
8/7/2021	Palo Verde	320030073	83	100	80.6	100*	--	--	--	--
8/7/2021	Paul Meyer	320030043	81	100	63.9	100	--	--	--	--
8/7/2021	Virgin Valley High School	320030024	73	100*	100.7	100*	--	--	--	--
8/7/2021	Walnut Comm. Center	320032003	79	100*	98.2	100*	700	88.2*	39.2	85.6*
8/7/2021	Walter Johnson	320030071	82	99.7	85.2	100*	--	--	--	--

*Sites that have less than five years of data available for a given parameter.

4.6 August 19, 2021

4.6.1 Event Summary

The unrepresentative ozone event took place on August 19, 2021, and affected five sites in Clark County, NV: Joe Neal, Palo Verde, Paul Meyer, Walnut Community Center, and Walter Johnson. Time series graphs showing hourly ozone concentrations exceeding the seasonal means (calculated using May 1 – October 31, 2017-2021) and 10th-90th percentiles at each site are shown in Figure 104.

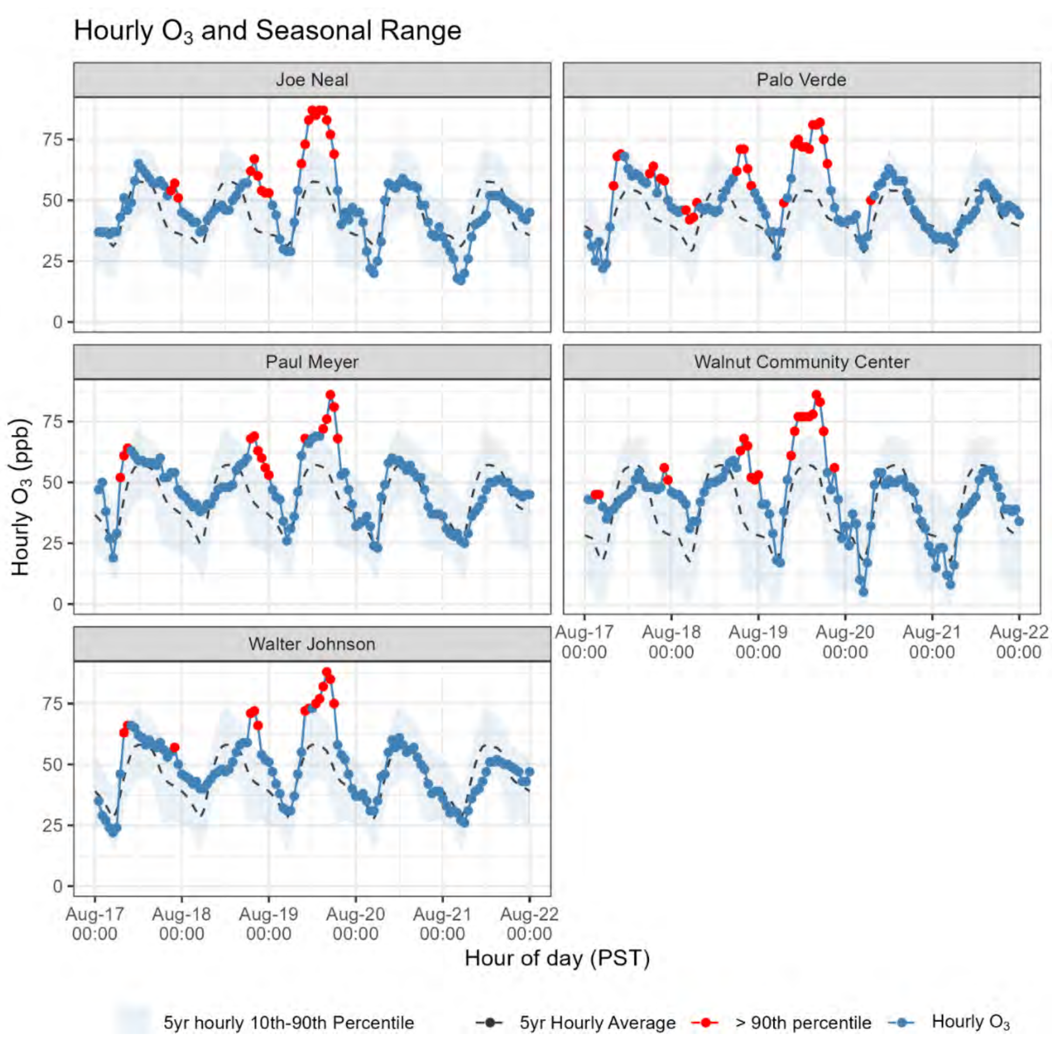

Figure 104. Hourly ozone concentrations (ppb) compared to 5-yr* ozone season (May 1-October 31) hourly means and 10th-90th percentiles. Note: data collected from the Walnut Community Center site is only available for June 1-October 31, 2021.

On August 18, hourly ozone concentrations exceeded the 90th percentile late in the day between 19:00-23:00 PST, and throughout August 19 from 09:00 to 19:00 PST. The MDA8 concentrations at affected sites ranged from 73-82 ppb: 82 ppb at the Joe Neal site, 78 ppb at the Walnut Community Center and Walter Johnson sites, 76 ppb at the Palo Verde site, and 73 ppb at the Paul Meyer site.

An abundance of regional, widespread smoke from at least 12 wildfires was identified as a major contributor to this event. Evidence includes (1) HYSPLIT dispersion modeling indicating the presence of smoke accumulation in Clark County, (2) remote sensing imagery and HMS smoke boundaries showing smoke over Clark County, (3) elevated concentrations of ground-level $PM_{2.5}$, CO, and NO_2, as well as enhanced $PM_{2.5}$-to-PM_{10} ratios that aligned with elevated ozone levels. Hourly $PM_{2.5}$ concentrations were three times higher than the 5-yr 90th percentile range, and smoke was visible in ground-based visibility camera and satellite imagery. The combination of this evidence and the results of dispersion modeling strongly indicate that this is an unrepresentative event for assessing base and future ozone design values.

4.6.2 Identification of Wildfires

Numerous wildfires throughout the western U.S. and Canada were actively burning on August 19, 2021, the exclusion day, and contributed to widespread regional smoke. Active wildfires were identified in California, Oregon, and Washington (**Figure 105 and Figure 106**). Regional smoke from these fires is present during mid-August 2021 throughout the western U.S., and this was verified for the days of August 17-19 based on smoke and wildfire detection geodata provided by the NOAA HMS (**Figure 107**). **Table 22** lists the state location, total acres within the fire perimeter, actively burning acres on the exclusion day, and the start and containment dates for each fire based on data from the WFIGS Current Interagency Fire Perimeters, and the Satellite Fire Occurrence and Growth database.[14]

[14] McClure et al. (2023) Consistent, high-accuracy mapping of daily and sub-daily wildfire growth with satellite observations. International Journal of Wildland Fire 32, 694-708. Available at **https://www.publish.csiro.au/wf/ExportCitation/WF22048**.

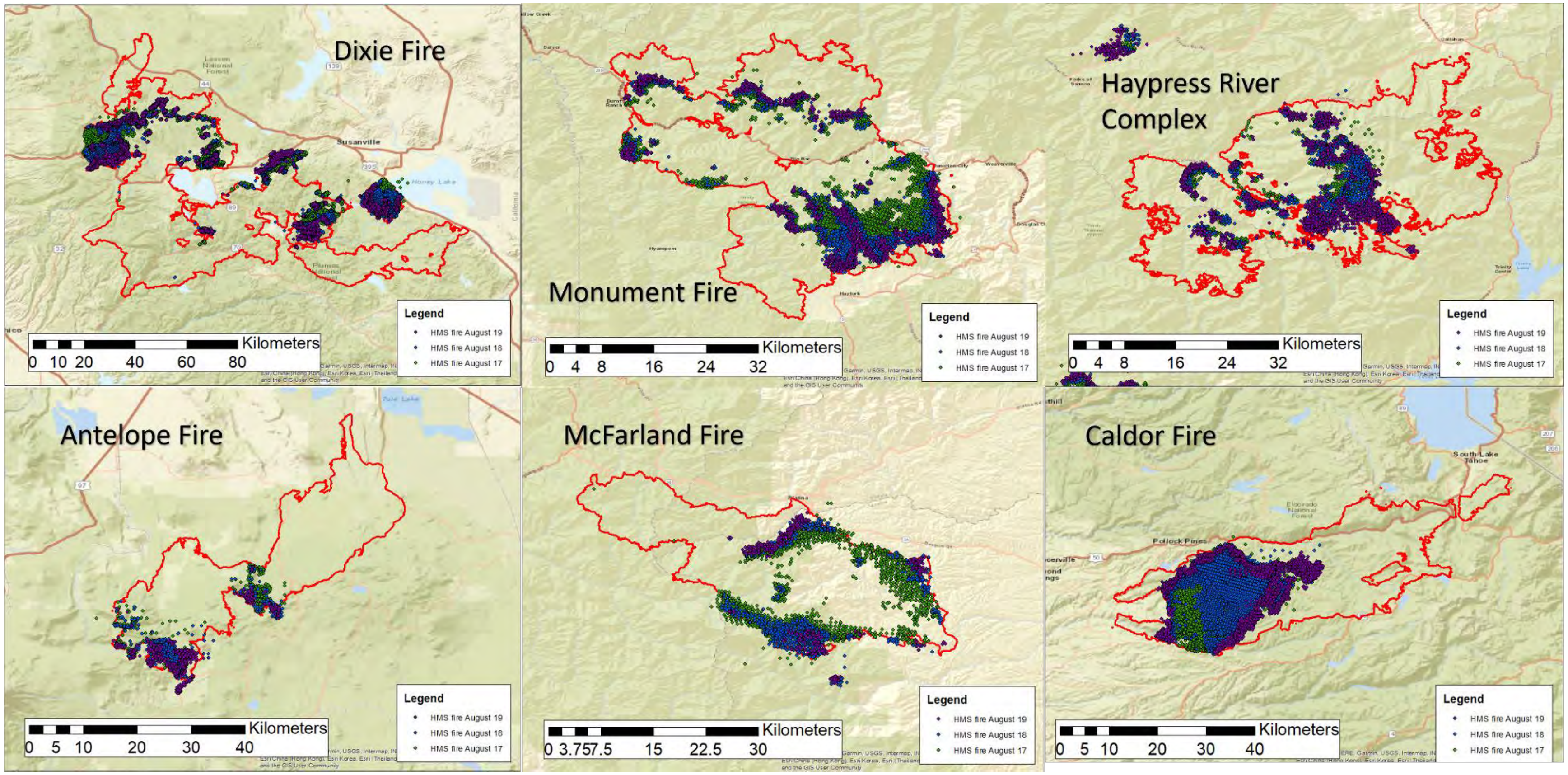

Figure 105. Final fire perimeters (red) and HMS fire detections for the Dixie, Monument, Haypress River Complex, Antelope, McFarland, and Caldor Fires during August 17-19, 2021.

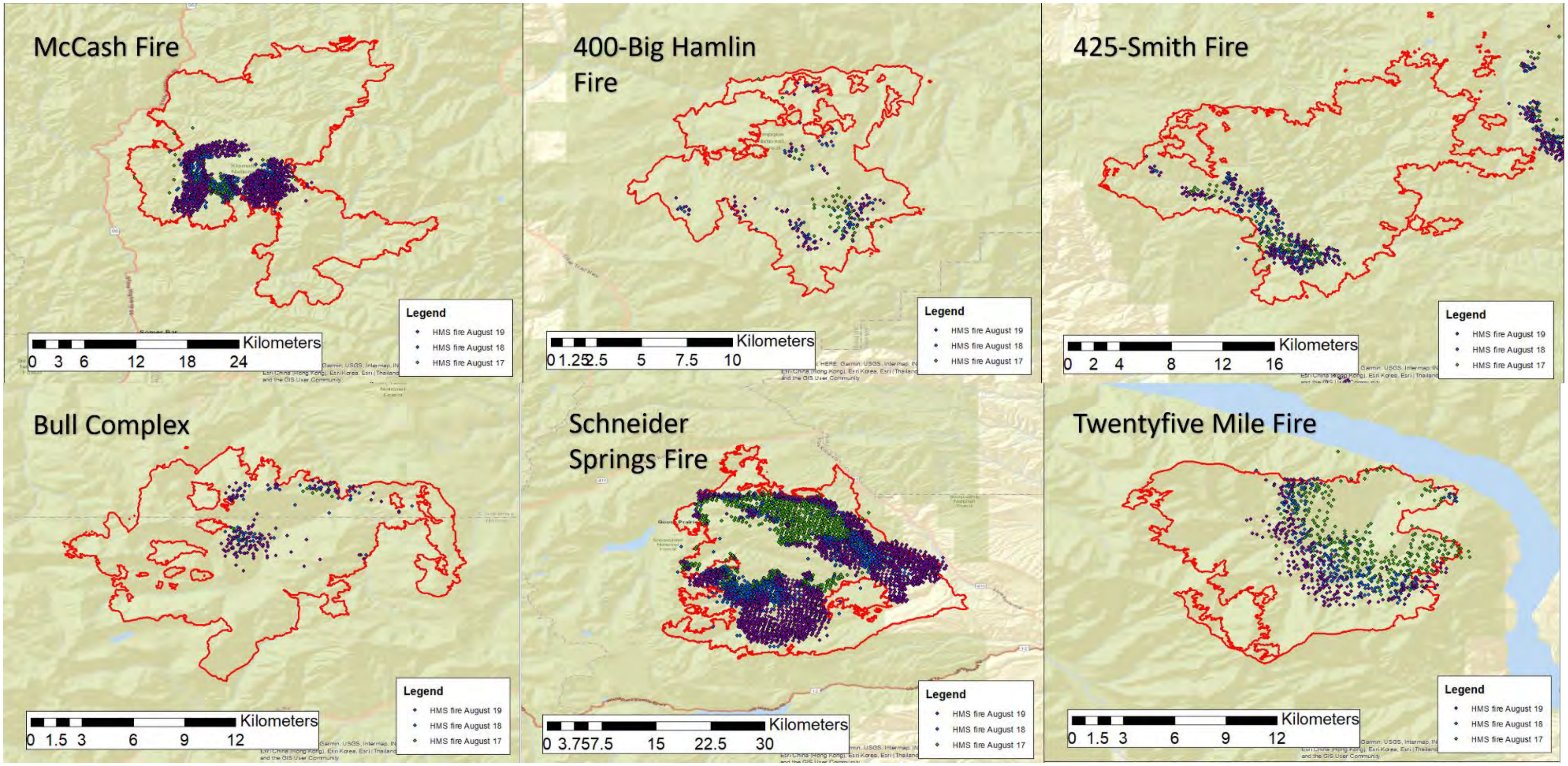

Figure 106. Final fire perimeters (red) and HMS fire detections for the McCash, Big Hamlin, Smith, Bull Complex, Schneider Springs, and Twentyfive Mile Fires during August 17-19, 2021.

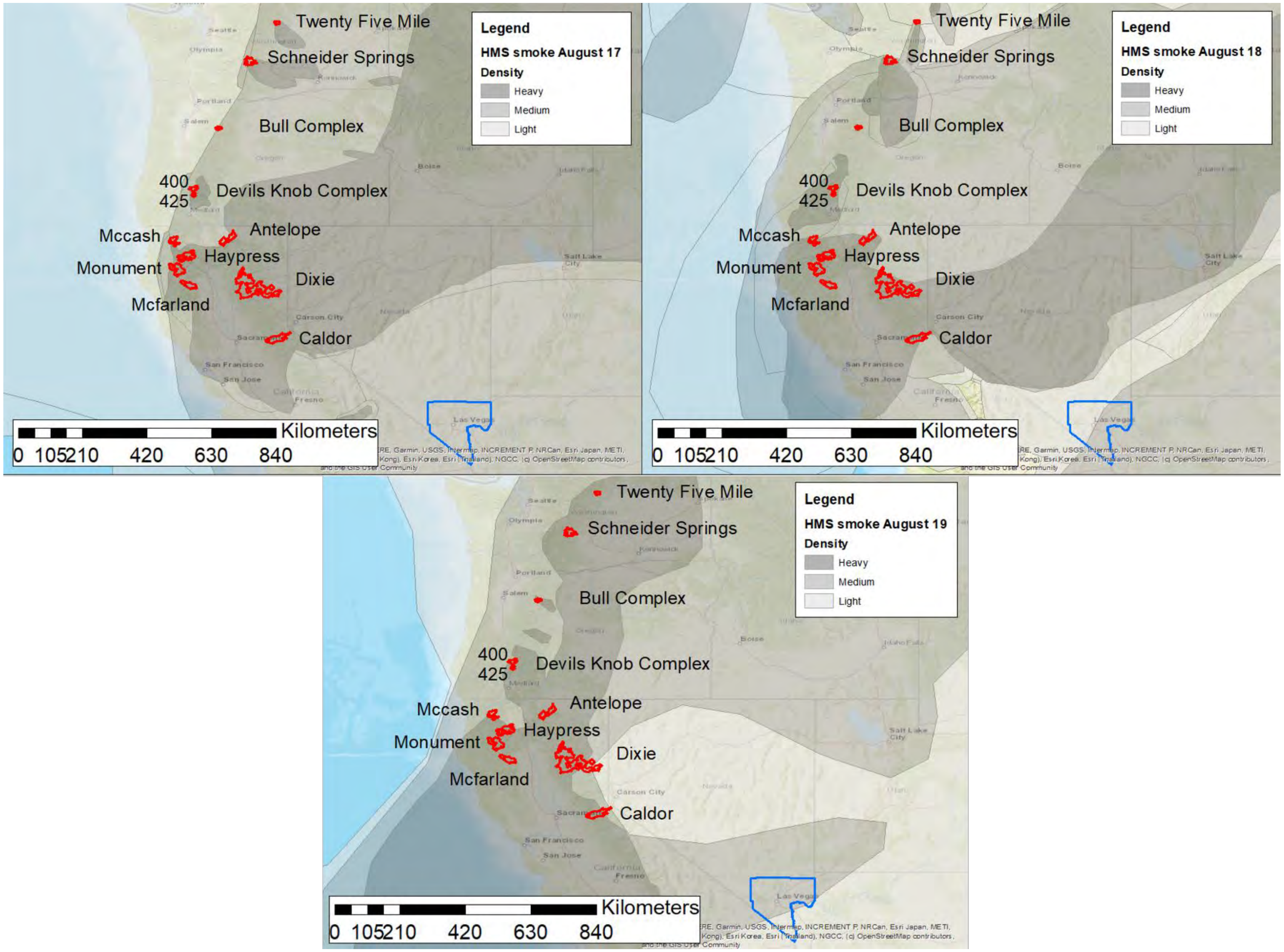

Figure 107. HMS smoke boundaries for August 17-19, 2021, is included with qualitative smoke density. Fire perimeters from the major fires contributing to the exclusion date are shown in red and the Clark County, NV, boundary is shown in blue.

Table 22. Wildfires affecting Clark County on the exclusion day. Where active areas are not available, cumulative acres burned are listed in italics.

Wildfire Name	State	Total Acres	Active Acres August 19	Start Date	Containment Date
Dixie	California	963,405	59,497	July 14	October 15
Monument	California	223,124	24,756	July 31	October 20
Haypress River Complex	California	199,343	25,279	July 31	October 25
Antelope	California	145,632	9,833	August 1	October 14
McFarland	California	122,653	6,331	July 30	September 16
Caldor	California	221,835	28,878	August 15	NA
McCash	California	94,962	10,264	August 1	October 27
400-Big Hamlin (Devils Knob Cpx)	Oregon	19,377	16,923[15]	August 7	NA
425-Smith (Devils Knob Cpx)	Oregon	49,238	4,037[15]	August 2	NA
Bull Complex	Oregon	24,894	5,761[16]	August 1	NA
Schneider Springs	Washington	107,353	56,422[17]	August 4	November 3
Twentyfive Mile	Washington	22,290	9,800[18]	August 15	October 19

4.6.3 Dispersion Modeling and Regional Analysis

HYSPLIT dispersion modelling was performed for August 16 through 19, 2021. Dispersion was initiated at 19:00 PST from each of the 12 actively burning fires impacting the exclusion date, August 19, 2021. GDAS 1.0° data horizontal resolution was used for meteorological input. Output from the dispersion modeling was integrated over a 24-hr period, from August 18 at 19:00 PST through August 19 at 19:00 PST. The accumulation of smoke at 0-100 m for the 24-hr period is shown in Figure 108.

The HYSPLIT dispersion modeling shows that smoke from multiple fires in California, Oregon, and Washington produced a dense layer of smoke that blanketed the western U.S. region, including Clark

[15] https://www.nrtoday.com/news/environment/wildfires/devils-knob-rough-patch-complexes-see-significant-growth-wednesday/article_27af1da7-405e-589e-a99c-53588b50ab70.html
[16] https://www.statesmanjournal.com/story/news/2021/08/18/oregon-wildfires-bull-complex-janus-butte-fire/8188419002/
[17] https://www.fox13seattle.com/news/level-3-evacuations-ordered-at-schneider-springs-fire
[18] https://lakechelannow.com/fire-update/

County, NV. The modeling results are consistent with the HMS smoke plume (shown in gray in Figure 108); HMS is an independent smoke identification database. The dispersion results indicate smoke from multiple fires reached Clark County, NV, on August 19, 2021, and that the smoke was present in the lower mixed layer, impacting surface conditions.

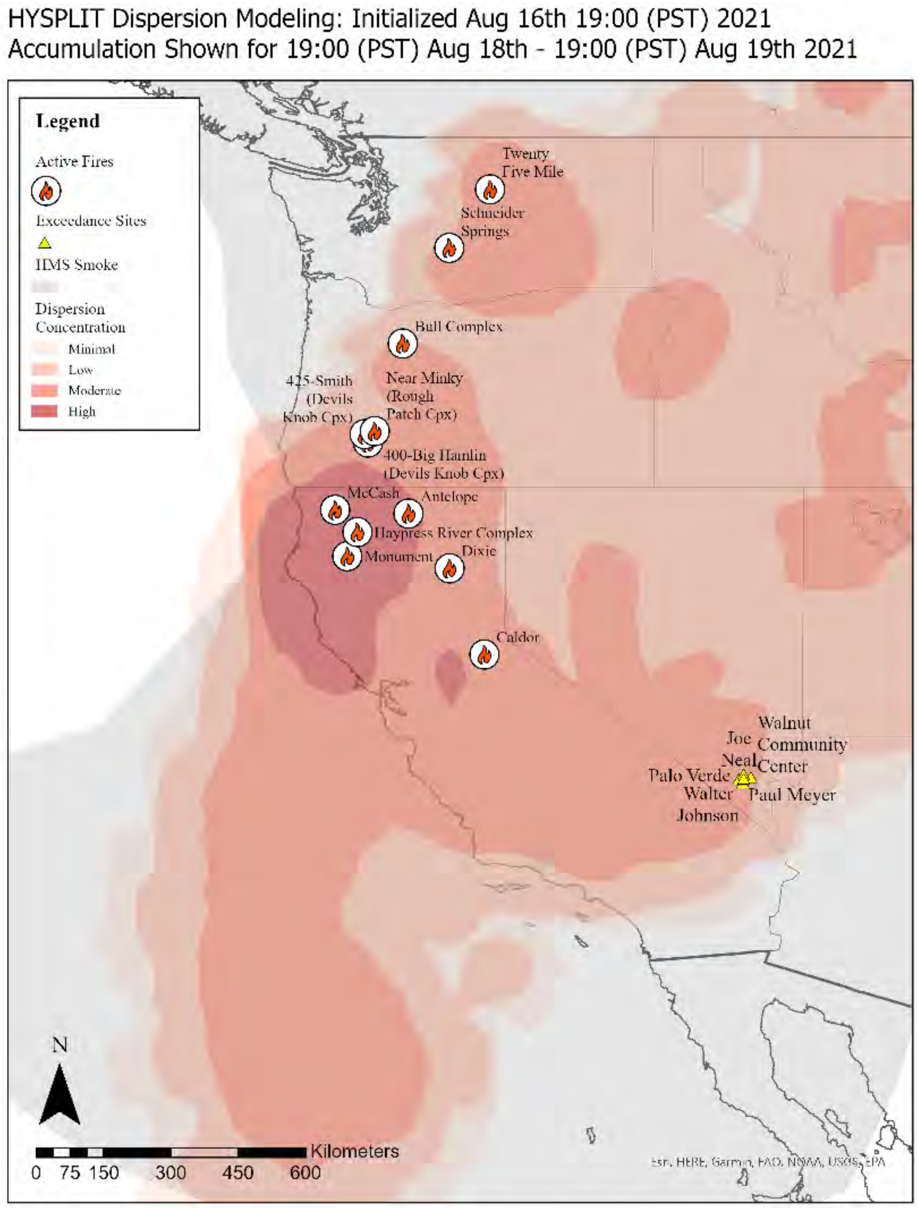

Figure 108. HYSPLIT dispersion modeling for 12 large fires (labeled as "Active Fires") throughout the western U.S. GDAS 1.0° meteorological data was used, and dispersion was initiated on August 16, 2021, at 19:00 PST to model the regional smoke observed in satellite and HMS products. HMS smoke is shown in gray and qualitative concentrations of particulate matter are shown in shades of red. Accumulation of particulate matter is shown at 0-100 m for 19:00 PST on August 18 through 19:00 PST on August 19, 2021.

MODIS Aqua visible satellite imagery confirms the extent of regional smoke shown in the dispersion modeling on August 19. Figure 109 shows regional smoke from the large California fires extending below the California Central Valley into southern Nevada, and directly affecting Clark County, NV.

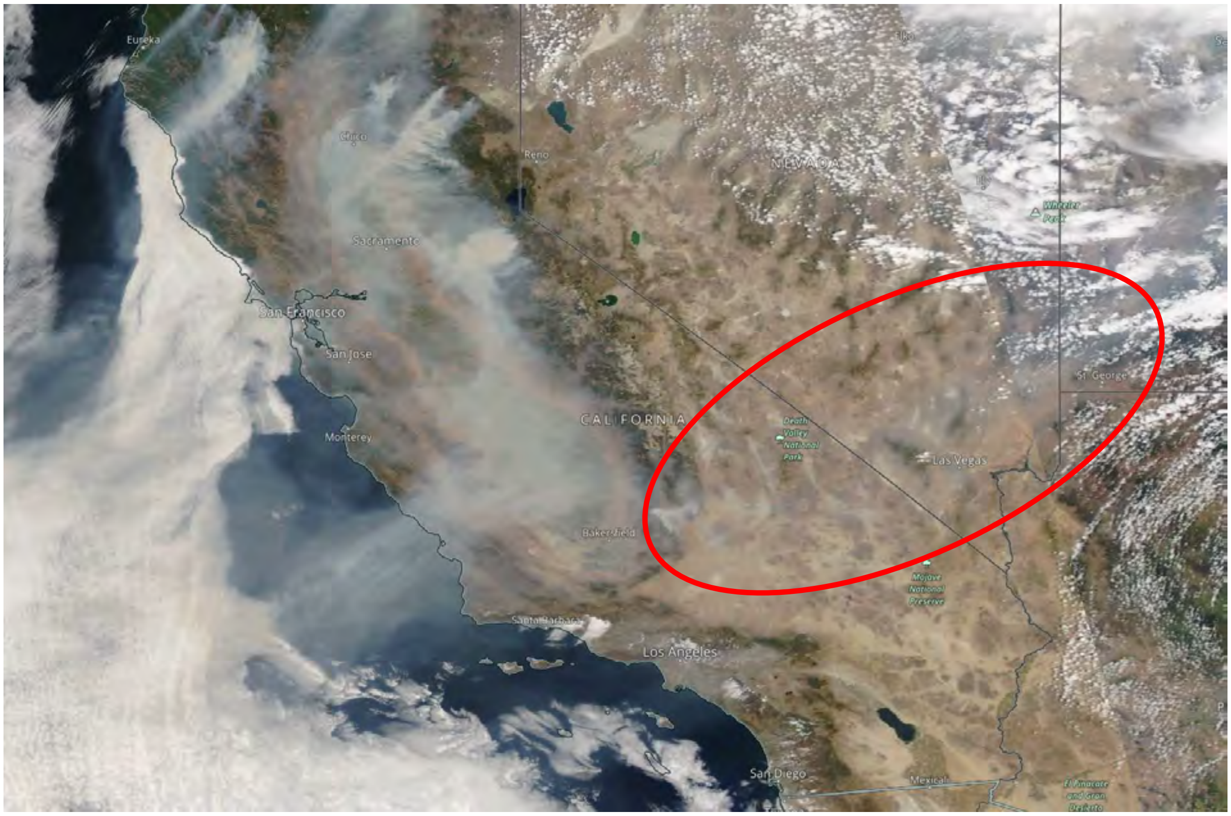

Figure 109. MODIS Aqua satellite image valid on August 19, 2021. Smoke from California wildfires is visible across central and southern Nevada. This smoke contributed to poor air quality and reduced visibility in Clark County. The red circle shows the area of smoke over Clark County.

4.6.4 Surface Impacts

The presence of wildfire smoke during the exclusion date is evident by comparing the morning time visibility conditions on August 18, 2021 (Figure 110), to the same time period on the exclusion date of August 19 (Figure 111). Local and regional smoke from the fires identified in Section 4.6.2 is visible in Clark County at 09:00 LST (09:00 PST) on August 19, when ozone photochemical production typically starts to accelerate. The local and regional smoke is an atypical influence on ozone and ozone precursors in the Clark County area and caused atypical ozone concentrations on the exclusion date. This is consistent with the Las Vegas (KLAS) hourly METAR reports for August 19 (Table 23), which noted smoke was present over several hours, as well as haze and reduced visibility as a result of smoke intrusion. The METAR also shows wind speeds were low at KLAS, which is favorable for ozone production with smoke intrusion.

Figure 110. Camera images showing the north (top left), south (bottom left), northeast (top right), and northwest (bottom right) coordinal directions, taken from the M Resort Hotel in Clark County, NV, on August 18, 2021, at 09:00 LST.

August 19, 2021, 09:00 LST

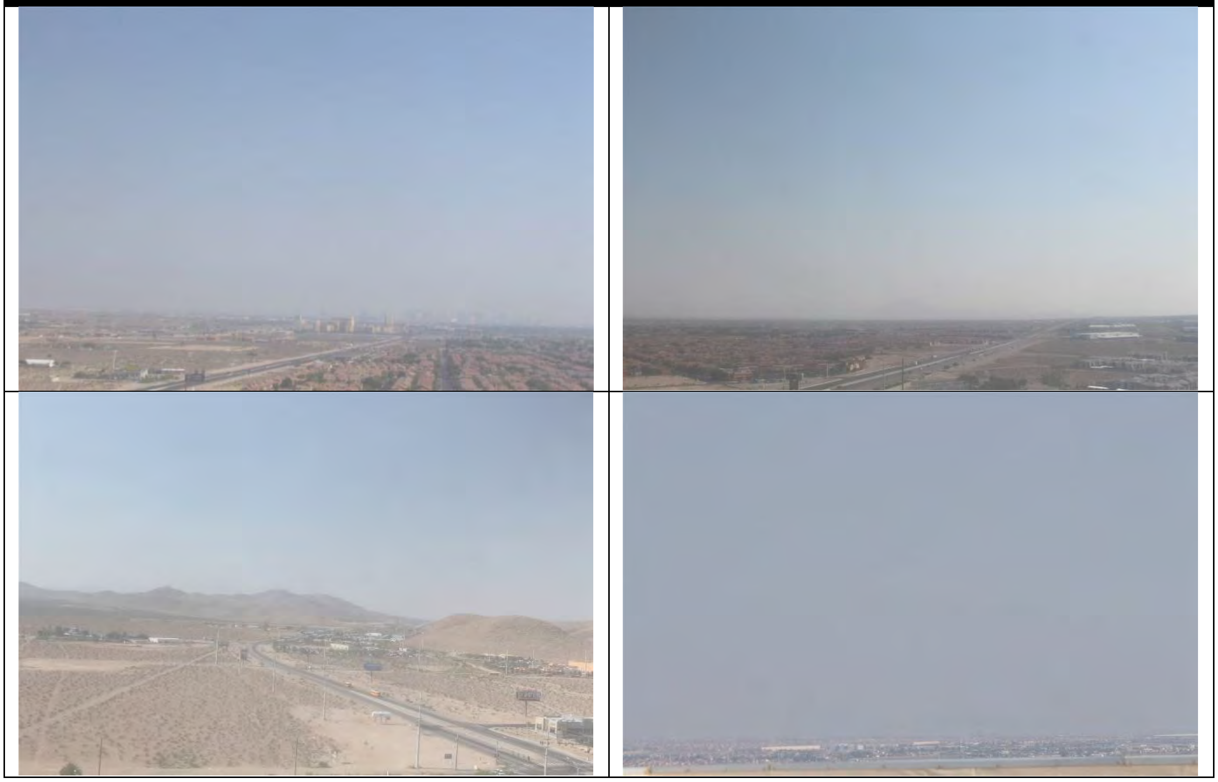

Figure 111. Camera images for north (top left), south (bottom left), northeast (top right), and northwest (bottom right) coordinal directions, taken from the M Resort Hotel in Clark County, NV, on August 19, 2021, at 09:00 LST.

Table 23. KLAS hourly METAR reports for August 19, 2021, between 09:00-23:00 UTC. During this period, the METAR remarks noted "FU" (meaning Smoke) in the Sky observations field.

August 19 Time (UTC)	Wind Direction / Speed	Visibility (Sq. Miles)	Sky Conditions
08:56	030 / 07 KT	9 SM	FU (SMOKE)
09:56	060 / 05 KT	7 SM	FU (SMOKE)
10:56	100 / 03 KT	7 SM	FU (SMOKE)
11:56	000 / 00 KT	9 SM	FU (SMOKE)
12:56	280 / 05 KT	9 SM	FU (SMOKE)
13:56	210 / 03 KT	8 SM	FU (SMOKE)
14:56	190 / 03 KT	8 SM	FU (SMOKE)
15:56	000 / 00 KT	8 SM	FU (SMOKE)
16:56	VRB / 03 KT	9 SM	FU (SMOKE)
17:56	VRB / 04 KT	10 SM	
18:56	230 / 03 KT	10 SM	
19:56	190 / 06 KT	8 SM	FU (SMOKE)
20:56	240 / 05 KT	9 SM	FU (SMOKE)
21:56	240 / 05 KT	8 SM	FU (SMOKE)
22:56	VRB / 06 KT	8 SM	FU (SMOKE)
23:56	000 / 00 KT	7 SM	FU (SMOKE)

The presence of surface-level wildfire smoke on August 19 is also indicated by enhanced $PM_{2.5}$, CO, and NO_2 concentrations. $PM_{2.5}$ concentrations compared to the diurnal 10th-90th percentile $PM_{2.5}$ concentrations are shown for affected sites in Figure 112. Hourly $PM_{2.5}$ concentrations exceeded 65 µg/m^3 in Clark County on August 19, far exceeding the diurnal 90th percentile $PM_{2.5}$ concentrations at all sites that exceeded the Ozone NAAQS. The diurnal 10th-90th percentile range is calculated across five years (2017-2021) during the ozone season (May-October).

Concurrently, CO concentrations at the Joe Neal site exceeded the diurnal 90th percentile concentration throughout the day on August 19 (Figure 113). Figure 114 shows that morning time NO_2 concentrations also rose above the diurnal 90th percentile during the exclusion date.

Synchronous enhancement of $PM_{2.5}$, CO, and NO_2 concentrations on the exclusion date provides strong evidence that wildfire smoke was present in Clark County and acted as an atypical influence on ozone production.

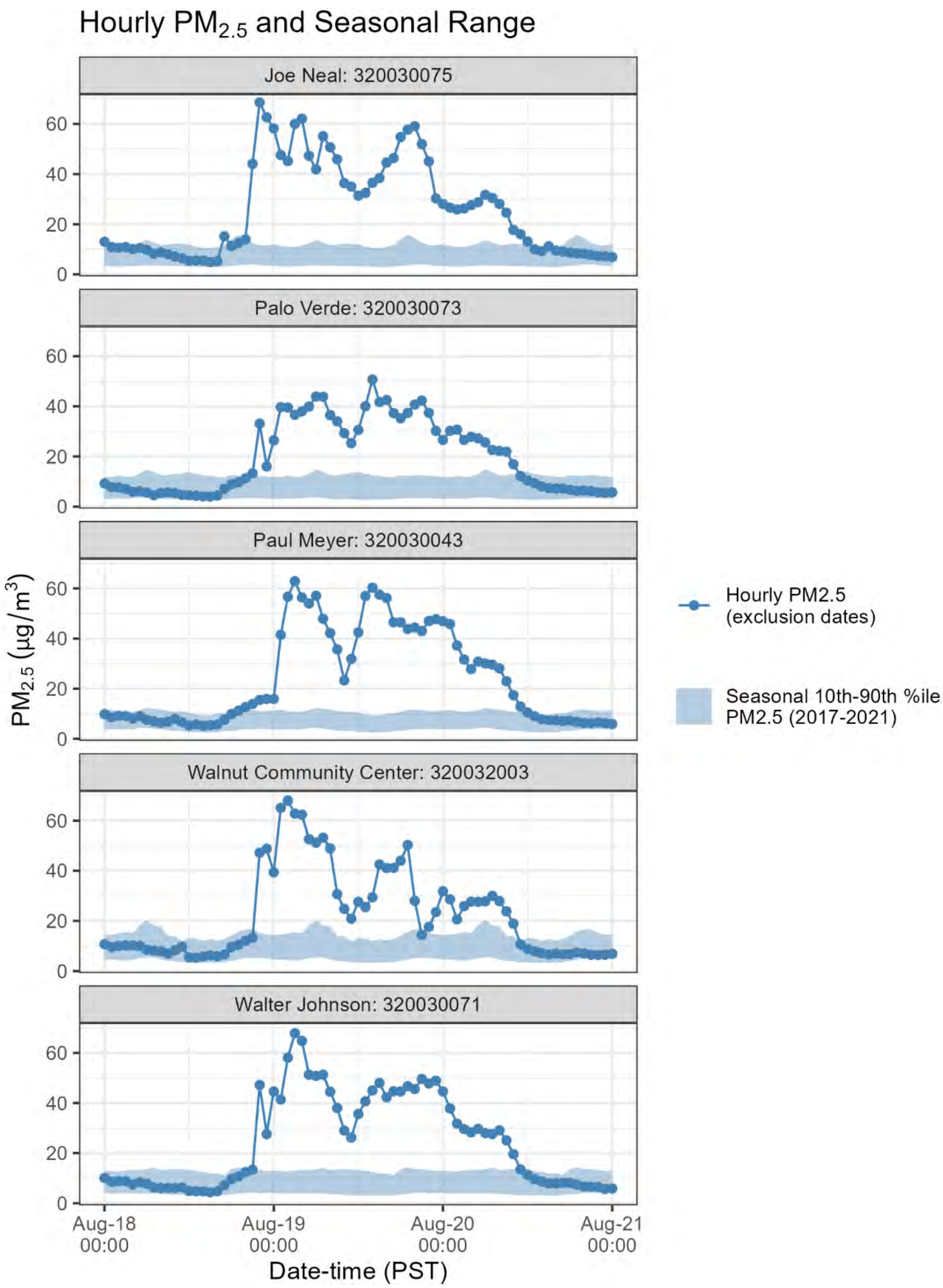

Figure 112. Hourly $PM_{2.5}$ measurements overlaid on the 10th-90th percentile diurnal concentration at affected sites that measure $PM_{2.5}$. The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021.

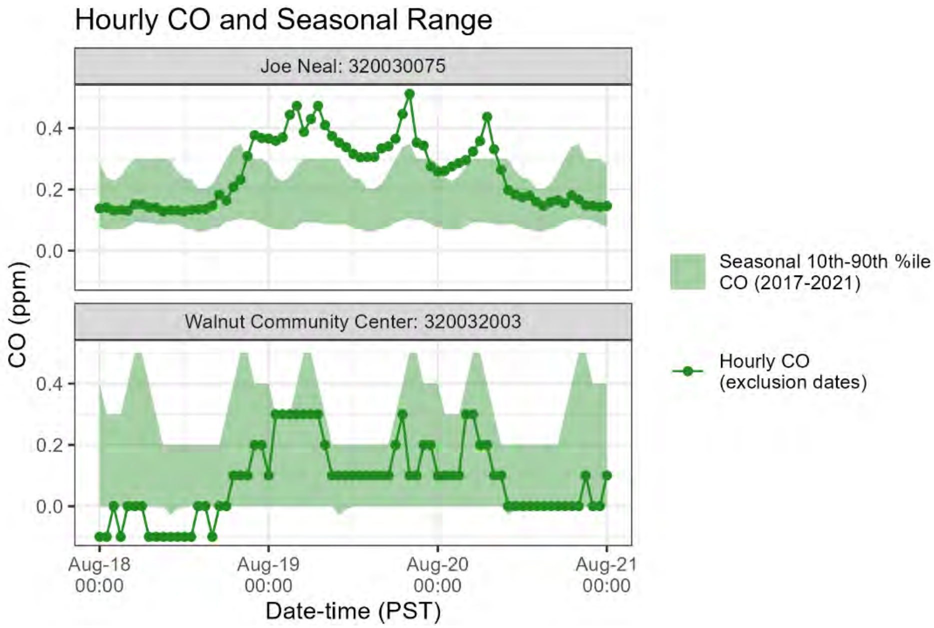

Figure 113. Hourly CO measurements overlaid on the 10th-90th percentile diurnal concentration at affected sites that measure CO. The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021.

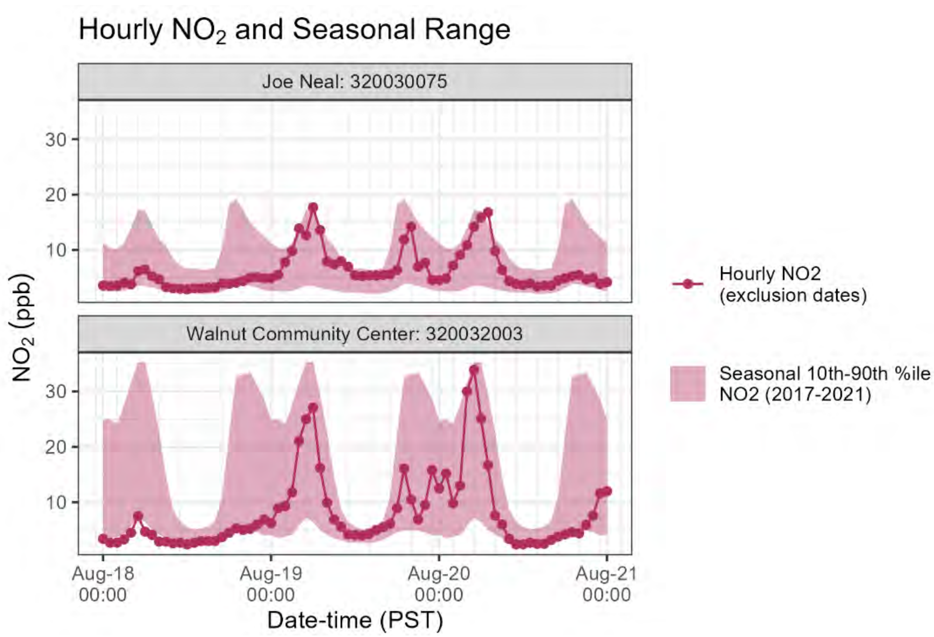

Figure 114. Hourly NO_2 measurements overlaid on the 10th-90th percentile diurnal concentration at affected sites that measure NO_2. The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021.

The ratio of $PM_{2.5}$-to-PM_{10} concentrations was also examined to determine if wildfire smoke entered Clark County on or before the exclusion dates. Increases in this ratio are indicative of wildfire smoke.

Figure 115 and Figure 116 show time series of the $PM_{2.5}$-to-PM_{10} ratio from August 18 through August 20, compared to the ozone season mean and 5th-95th percentile range for available data between 2017-2021 at all affected sites (Figure 115) and non-affected regional sites (Figure 116). Ratios at all sites were generally at or below average during the day on August 18, then exceeded the 95th percentile during the late evening of August 18 and morning and day of August 19. Ratios at all sites exceeded 0.6 in the early morning of August 19, remained elevated throughout the day, and slowly declined over the following day (August 20). A similar pattern is present at other sites throughout Clark County (Figure 116). These observations provide evidence that wildfire smoke entered Clark County in the late evening of August 18 and early morning of August 19, containing enhanced $PM_{2.5}$-to-PM_{10} ratios immediately prior to and during the atypical ozone events that occurred on August 19.

Figure 115. Ratio of $PM_{2.5}$-to-PM_{10} concentrations at the affected sites during the August 19 event period. The 5-yr average $PM_{2.5}$-to-PM_{10} diurnal ratio is displayed as a dotted line, and the 5th-95th percentile range is shown as a shaded ribbon. The 5th-95th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021.

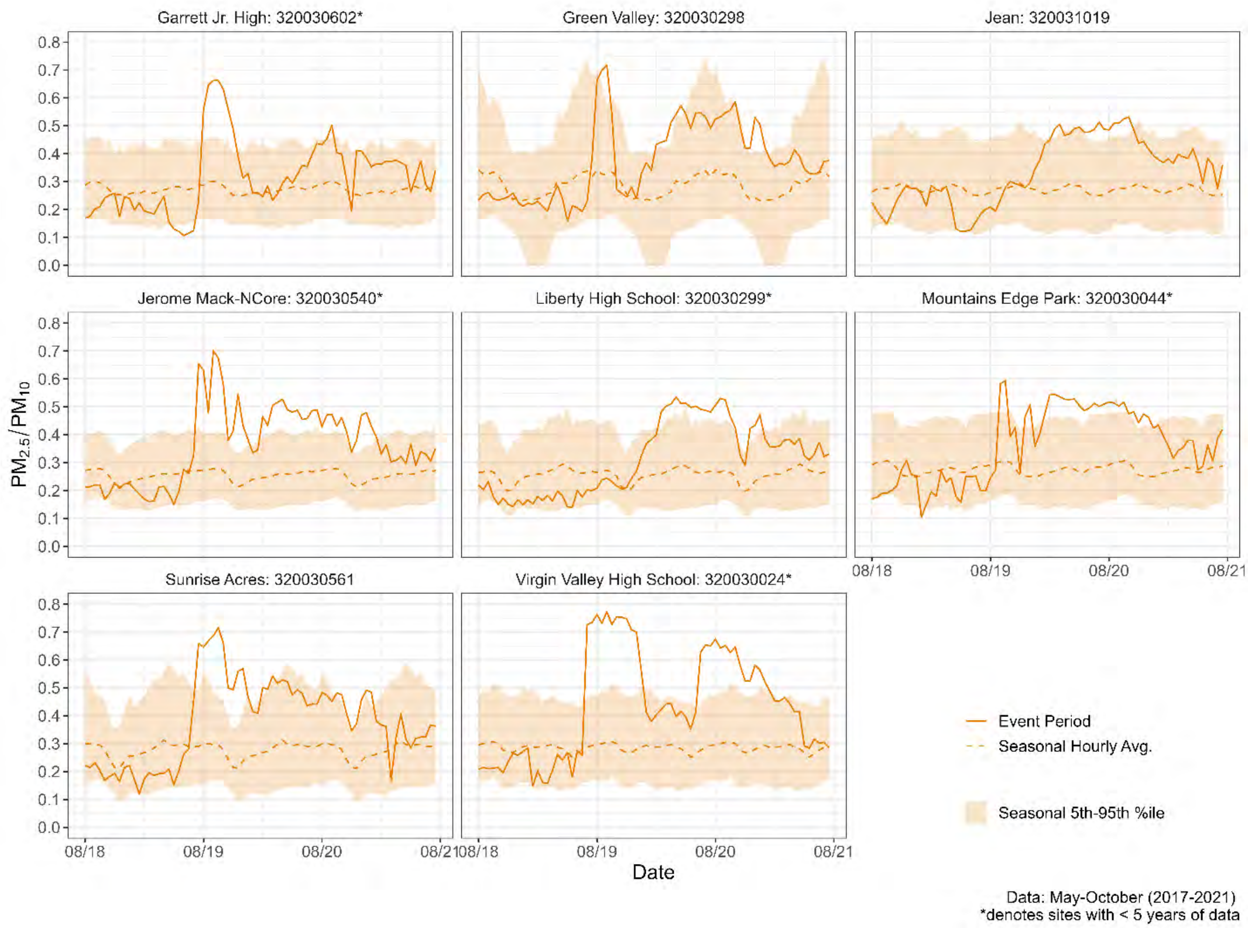

Figure 116. Ratio of $PM_{2.5}$-to-PM_{10} concentrations at the affected sites during the August 19 event period. The 5-yr average $PM_{2.5}$-to-PM_{10} diurnal ratio is displayed as a dotted line, and the 5th-95th percentile range is shown as a shaded ribbon. The 5th-95th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021.

4.6.5 Event Statistics

Table 24 summarizes the daily measurements of ozone, $PM_{2.5}$, CO, and NO_2 concentrations on the exclusion day, as well as the percentile rank of the observation compared to the previous five years of data (2017-2021). On August 19, 2021, ozone MDA8 measurements were above the 99th percentile for three out of the five sites, and above the 97th percentile for the remaining two sites. 24-hr average $PM_{2.5}$ measurements were above the 99th percentile at all sites, and 1-hr daily maximum measurements were elevated for CO (97th percentile) and NO_2 (67th percentile) at the Joe Neal site and lower at the Walnut Community Center site.

Table 24. Percentile of pollutant measurements on the exclusion day compared with most recent five years* (2017-2021). The percentile rank is calculated across the ozone production season (May 1-October 31) of 2017-2021.

Date	Site Name	Site Code	Ozone		$PM_{2.5}$		CO		NO_2	
			Ozone MDA8 (ppb)	Percent Rank	$PM_{2.5}$ 24-hr Avg ($\mu g/m^3$)	Percent Rank	CO 1-hr Daily Max (ppb)	Percent Rank	NO_2 1-hr Daily Max (ppb)	Percent Rank
8/19/2021	Paul Meyer	320030043	73	97.6	46.5	99.8	--	--	--	--
8/19/2021	Walter Johnson	320030071	78	99.2	46.1	99.7*	--	--	--	--
8/19/2021	Palo Verde	320030073	76	99.4	37.4	99.5*	--	--	--	--
8/19/2021	Joe Neal	320030075	82	99.9	46.4	99.9*	512	97.1*	17.7	66.9
8/19/2021	Walnut Comm. Center	320032003	78	98.7*	40.2	99.3*	300	32.7*	27.1	45.1*

*Sites that have less than five years of data available for a given parameter.

4.7 September 8, 2021

4.7.1 Event Summary

The unrepresentative ozone event took place on September 8, 2021, and affected two sites in Clark County, Nevada: Palo Verde and Walter Johnson. The MDA8 concentrations were 71 ppb at Palo Verde and 73 ppb at Walter Johnson. Time series showing hourly ozone concentrations compared to the 5-yr seasonal means and 10th-90th percentiles (calculated using May 1-October 31, 2017-2021) at each site are shown in Figure 117.

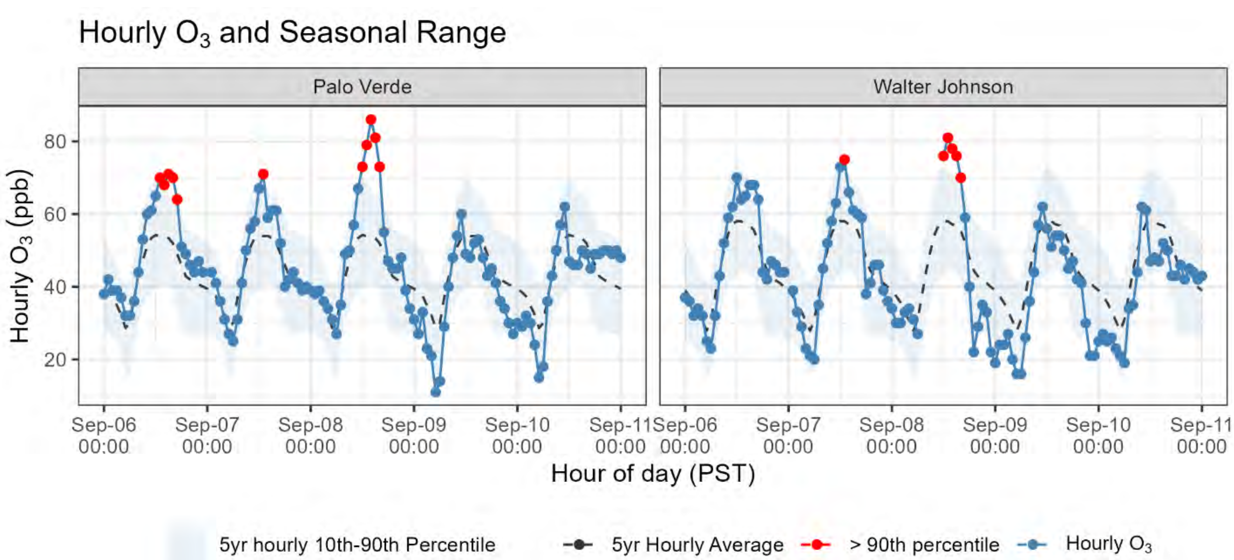

Figure 117. Hourly ozone concentrations (ppb) compared to 5-yr ozone season (May 1-October 31, 2017-2021) hourly means and 10th-90th percentiles.

Midday peaks began exceeding the 5-yr mean on September 5 and returned to normal values on September 9, 2021. On September 8, hourly ozone measurements exceeded the 5-yr 90th percentile at both sites from as early as 09:00 to 16:00 PST. Hourly ozone measurements were not available on September 8 from 07:00-11:00 PST at the Walter Johnson site.

Regional wildfire smoke likely influenced this event: in early September there were 13 active wildfires potentially contributing, with 150,000 acres actively burning in California alone. HYSPLIT back trajectories and dispersion modeling connect smoke plumes from these fires to surface conditions in Clark County. Additional evidence includes a reduction in visibility observed in ground-based images and elevated ground-based $PM_{2.5}$, CO, NO_2, and $PM_{2.5}$-to-PM_{10} ratio measurements. The combination of evidence indicates that this is an unrepresentative event for assessing base and future ozone design values.

4.7.2 Identification of Wildfires

Numerous active wildfires were identified throughout the western U.S. and Canada on September 8, 2021, the exclusion day (**Figure 118 and Figure 119**). Regional smoke from these fires was present during early September 2021 throughout the western U.S., and this was verified for the days of September 6-8 through visualization of smoke and wildfire detection geodata provided by the NOAA HMS (**Figure 120**). **Table 25** lists the state location, total acres within the fire perimeter, actively burning acres on the exclusion day, and the start and containment dates for each fire based on data from the WFIGS Current Interagency Fire Perimeters and the Satellite Fire Occurrence and Growth database.[19]

[19] McClure et al. (2023) Consistent, high-accuracy mapping of daily and sub-daily wildfire growth with satellite observations. International Journal of Wildland Fire 32, 694-708. Available at **https://www.publish.csiro.au/wf/ExportCitation/WF22048**.

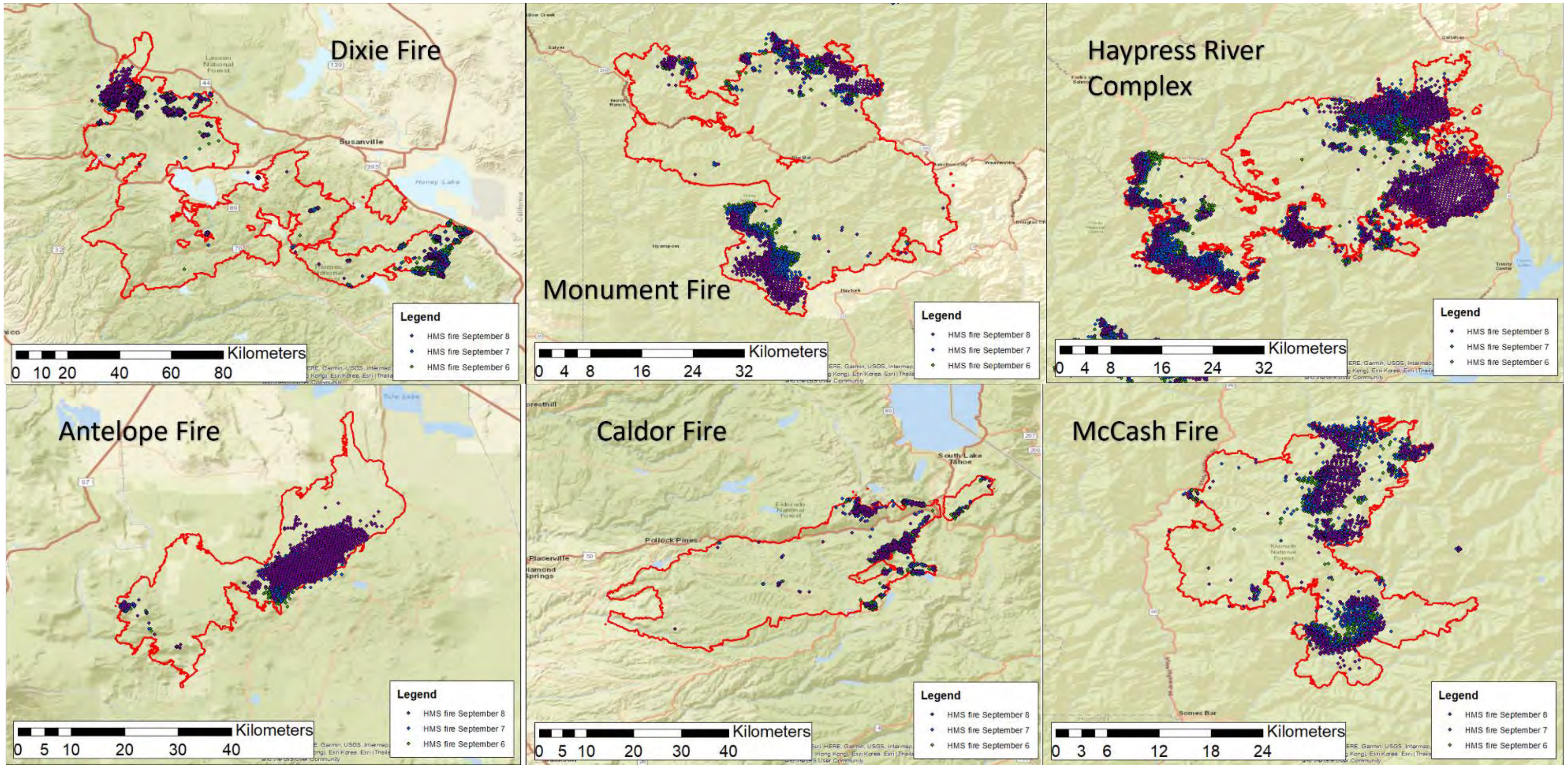

Figure 118. Final fire perimeters (red) and HMS fire detections for the Dixie, Monument, Haypress River Complex, Antelope, Caldor, and McCash Fires during September 6-8, 2021.

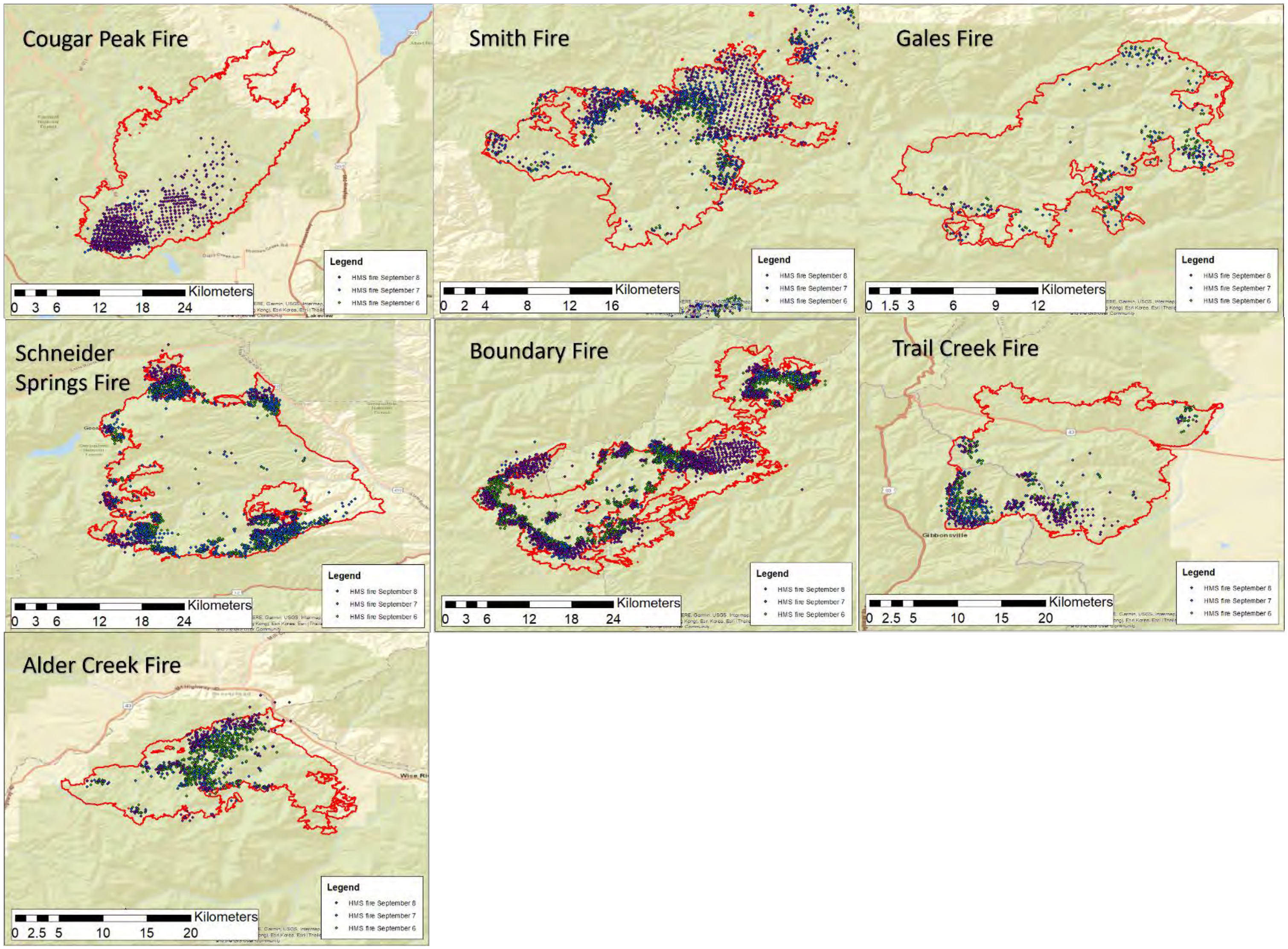

Figure 119. Final fire perimeters (red) and HMS fire detections for the Cougar Peak, Smith, Gales, Schneider Springs, Boundary, Trail Creek, and Alder Creek Fires during September 6-8, 2021.

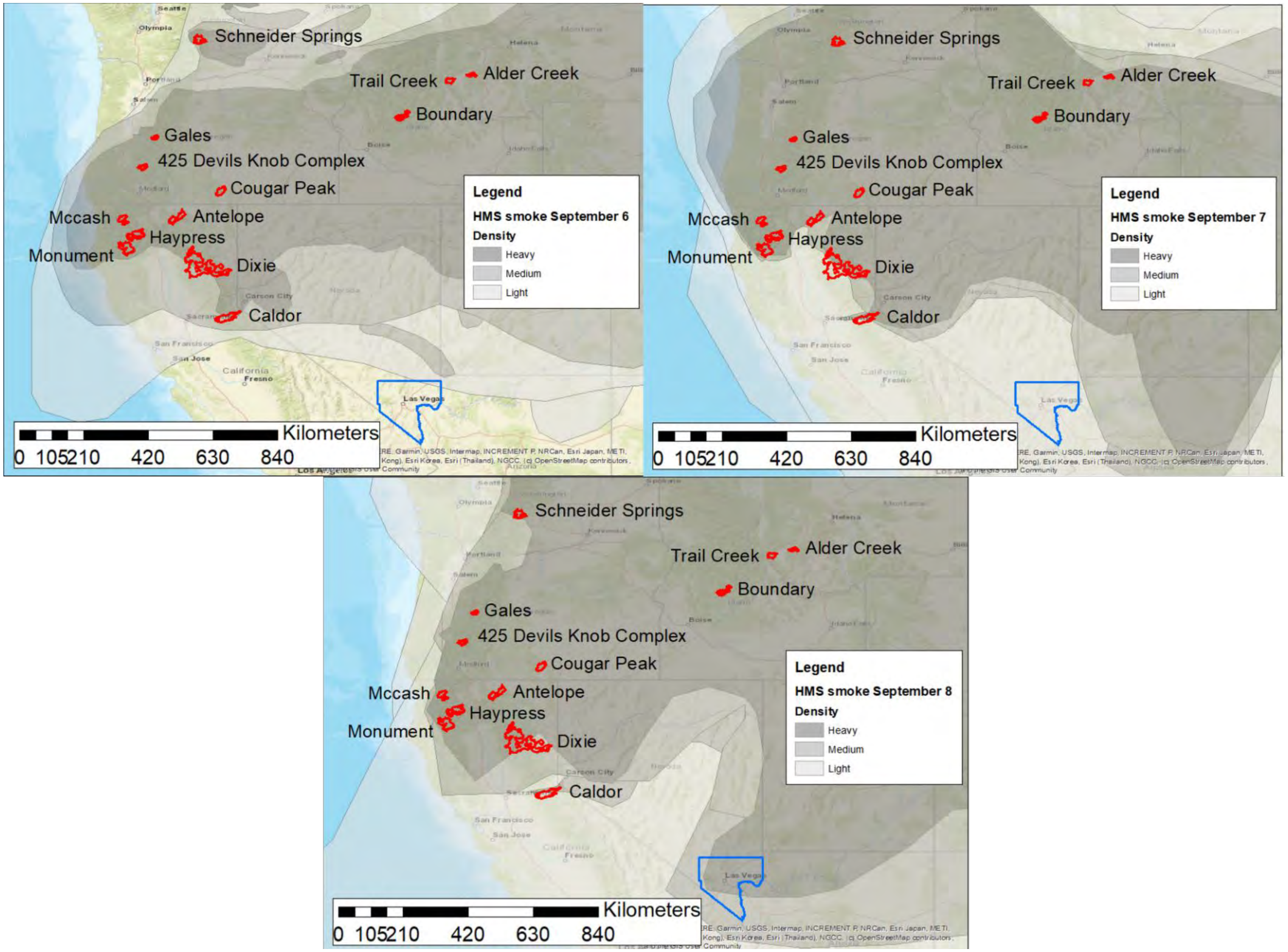

Figure 120. HMS smoke for September 6-8, 2021, is included with qualitative smoke density. Fire perimeters from the major fires contributing to the exclusion date are shown in red and the Clark County, NV, boundary is shown in blue.

Table 25. Wildfires affecting Clark County on the exclusion day. The fire name, state location, total acreage, active acreage burning on the exclusion day, and the start and containment date are included. Where active areas are not available, cumulative acres burned are listed in italics.

Wildfire Name	State	Total Acres	Active Acres as of September 8	Start Date	Containment Date
Dixie	California	963,405	20,988	July 14	October 15
Monument	California	223,124	19,710	July 31	October 20
Haypress River Complex	California	199,343	54,374	July 31	October 25
Antelope	California	145,632	27,608	August 1	October 14
Caldor	California	221,835	8,688	August 15	NA
McCash	California	94,962	17,519	August 1	October 27
Cougar Peak	Oregon	91,701	20,000[20]	September 7	October 21
425-Smith (Devils Knob Cpx)	Oregon	49,238	39,579[21]	August 2	N/A
Gales (Middle Fork Complex)	Oregon	24,894	*26,031[22] (whole complex)*	July 27	N/A
Schneider Springs	Washington	107,353	*97,288[23]*	August 4	November 3
Boundary	Idaho	79,721	*49,784[24] (September 10)*	August 10	November 23
Trail Creek	Idaho	61,992	*42,042[25] (as of September 7)*	July 8	November 4
Alder Creek	Idaho	36,968	*28,377[25] (as of September 7)*	July 8	November 3

[20] https://www.oregonlive.com/pacific-northwest-news/2021/09/cougar-peak-fire-in-lake-county-grows-to-1500-acres-prompts-evacuations.html
[21] https://www.nrtoday.com/news/environment/wildfires/level-3-go-evacuation-ordered-for-residents-near-smith-fire-on-devils-knob-complex/article_7e12117e-ce12-5266-a224-53db9fe790a7.html
[22] https://www.nwfirescience.org/aggregator/sources/21?page=49
[23] https://m.facebook.com/SchneiderSpringsFire/posts/169202121972001/
[24] https://localnews8.com/news/idaho/2021/09/10/boundary-fire-grows-to-49784-acres/
[25] https://opi.mt.gov/Portals/182/Superintendent-Docs-Images/SEPTEMBER%207%20DNRC%20WILDFIRE%20SITUATION%20REPORT.pdf

4.7.3 Dispersion Modeling and Regional Analysis

HYSPLIT dispersion modelling was performed for September 5 through 9, 2021. Dispersion was initiated at 06:00 PST to simulate regional smoke from the 13 identified active fires impacting the exclusion date. GDAS data at 1.0° horizontal resolution was used for meteorological input. Output from the dispersion modeling was integrated over a 24-hr period starting September 8 at 06:00 PST through September 9 at 06:00 PST. 06:00 PST was chosen to correspond with the initial increase of observed $PM_{2.5}$ concentrations in Clark County. The accumulation of smoke at 0-100 m for the 24-hr period is shown in **Figure 121**.

The HYSPLIT dispersion modeling results show that multiple fires produced a dense layer of smoke that blanketed the western U.S. region, including Clark County, NV. The modeling results are consistent with the HMS smoke plume (shown in gray in Figure 121); HMS is an independent smoke identification database. The dispersion results show smoke from multiple fires reached Clark County, Nevada, on September 8, 2021, and the smoke was present in the lower mixed layer of the atmosphere, impacting ground-level air quality conditions.

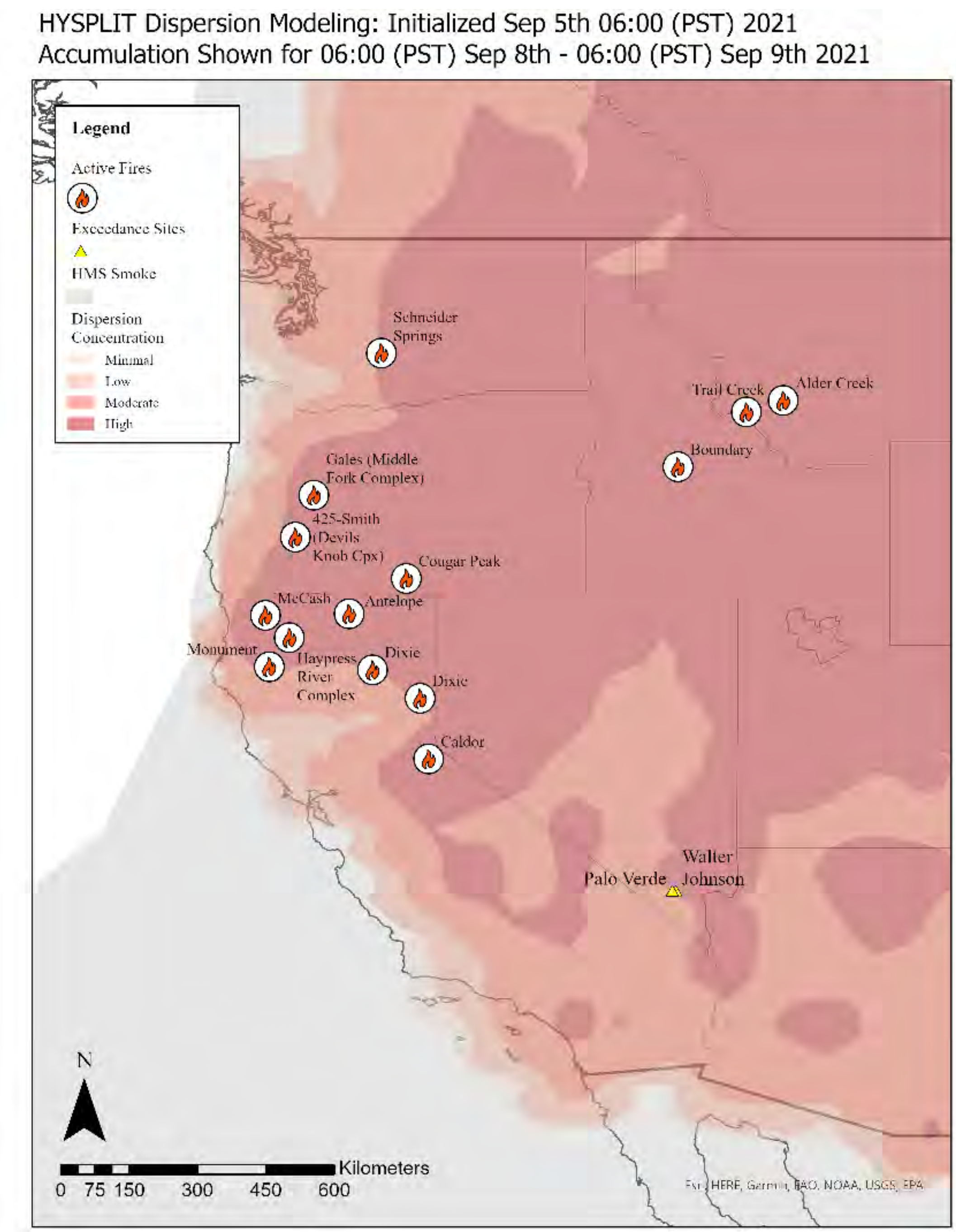

Figure 121. HYSPLIT dispersion modeling for 13 large fires (labeled as "Active Fires") throughout the western U.S. GDAS 1.0° meteorological data was used, and dispersion was initiated on September 5 at 06:00 PST to model the regional smoke observed in satellite and HMS products. HMS smoke is shown in gray and qualitative concentrations of particulate matter are shown in shades of red. Accumulation of particulate matter is shown at 0-100 m for 06:00 PST on September 8 through 06:00 PST on September 9, 2021. Note: the Dixie Fire is labeled twice because there was a significant distance between the active burning edges of the fire on these dates.

Back trajectories (Figure 122) were consistent with the results of the dispersion modeling and show transport from active fire areas and locations where dense smoke was observed by MODIS satellite imagery (Figure 123). Additionally, Figure 124 shows an upper-level high pressure system over central and eastern Nevada, which allowed wildfire smoke to be transported into Clark County and is consistent with the results of the dispersion modeling, back trajectories, and satellite imagery.

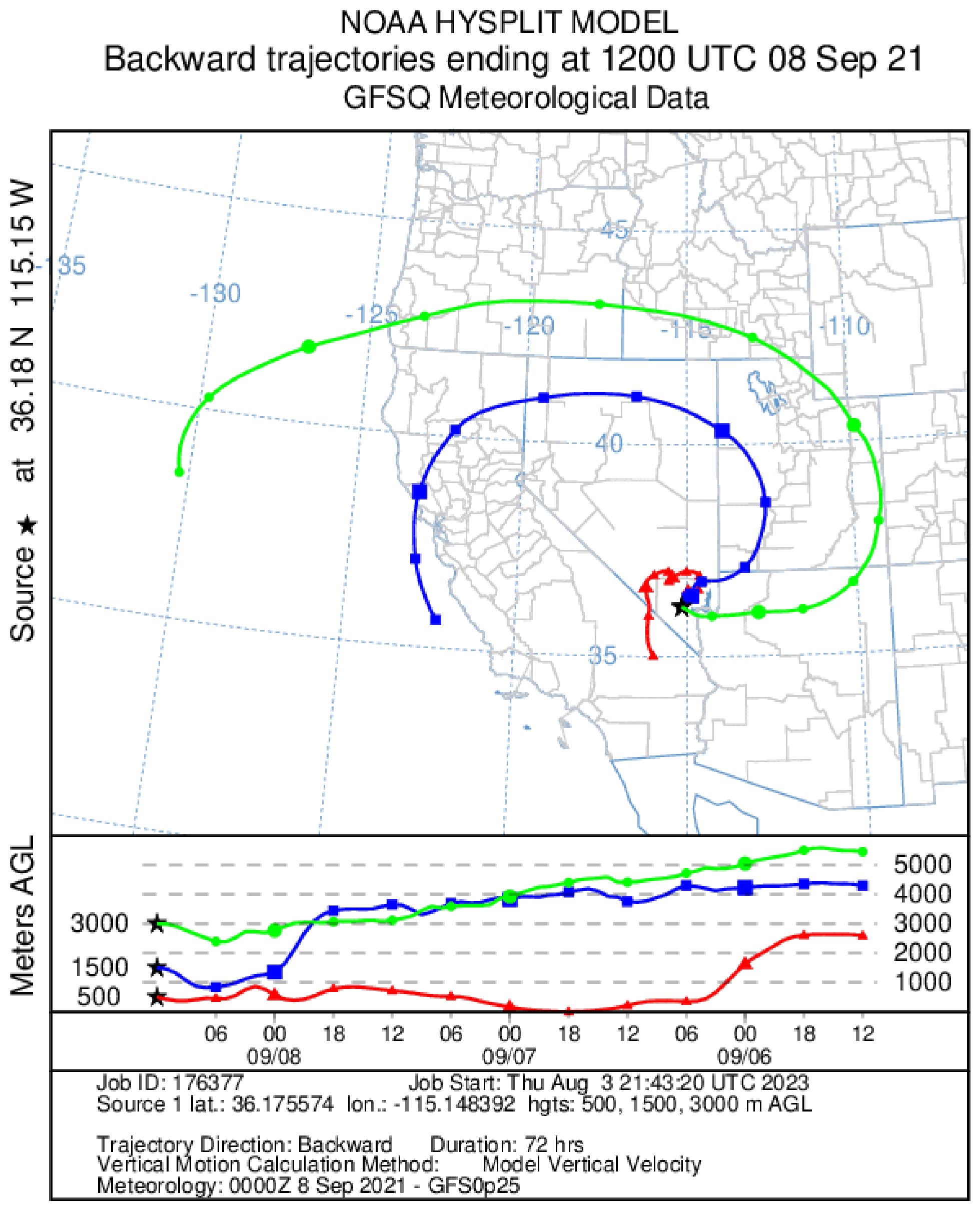

Figure 122. NOAA GFS HYSPLIT 72-hr back trajectory analysis ending at 12:00 UTC (04:00 PST) on September 8, 2021, shows smoke from fires in northern California and Oregon was likely transported into Clark County, NV, contributing to atypical ozone levels.

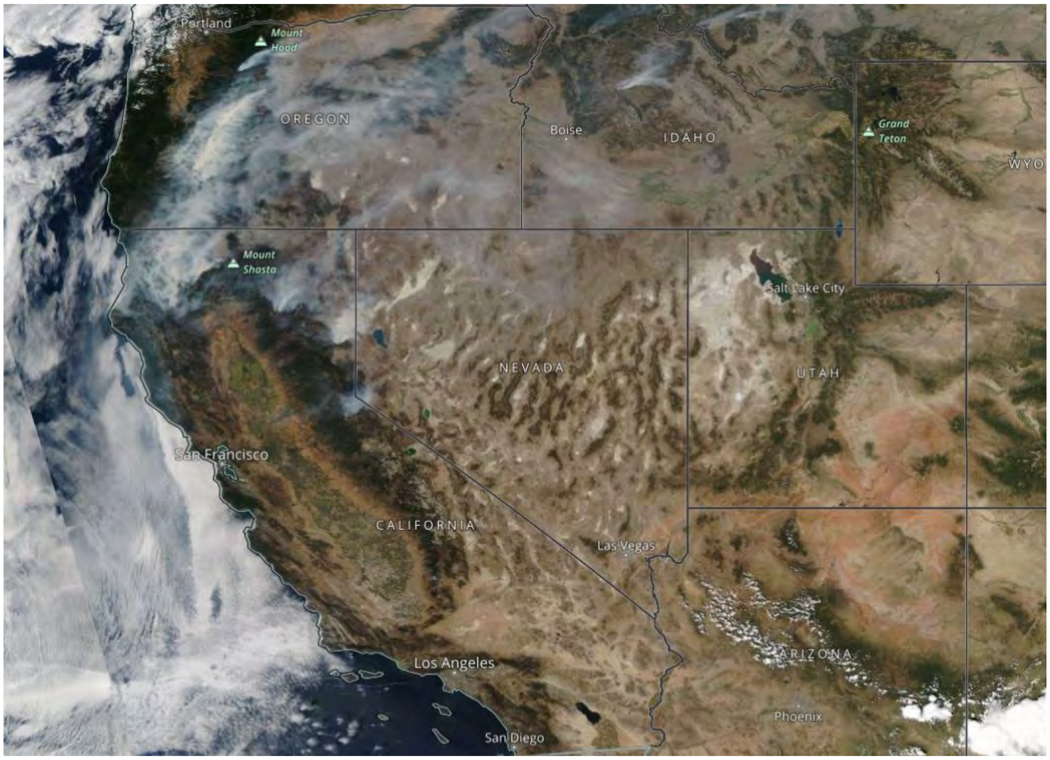

Figure 123. MODIS Aqua satellite image on September 5, 2021. Based on surface observations of haze and 72-hr back trajectory analysis on September 8, smoke from fires in northern California and Oregon impacted air quality in Clark County, NV.

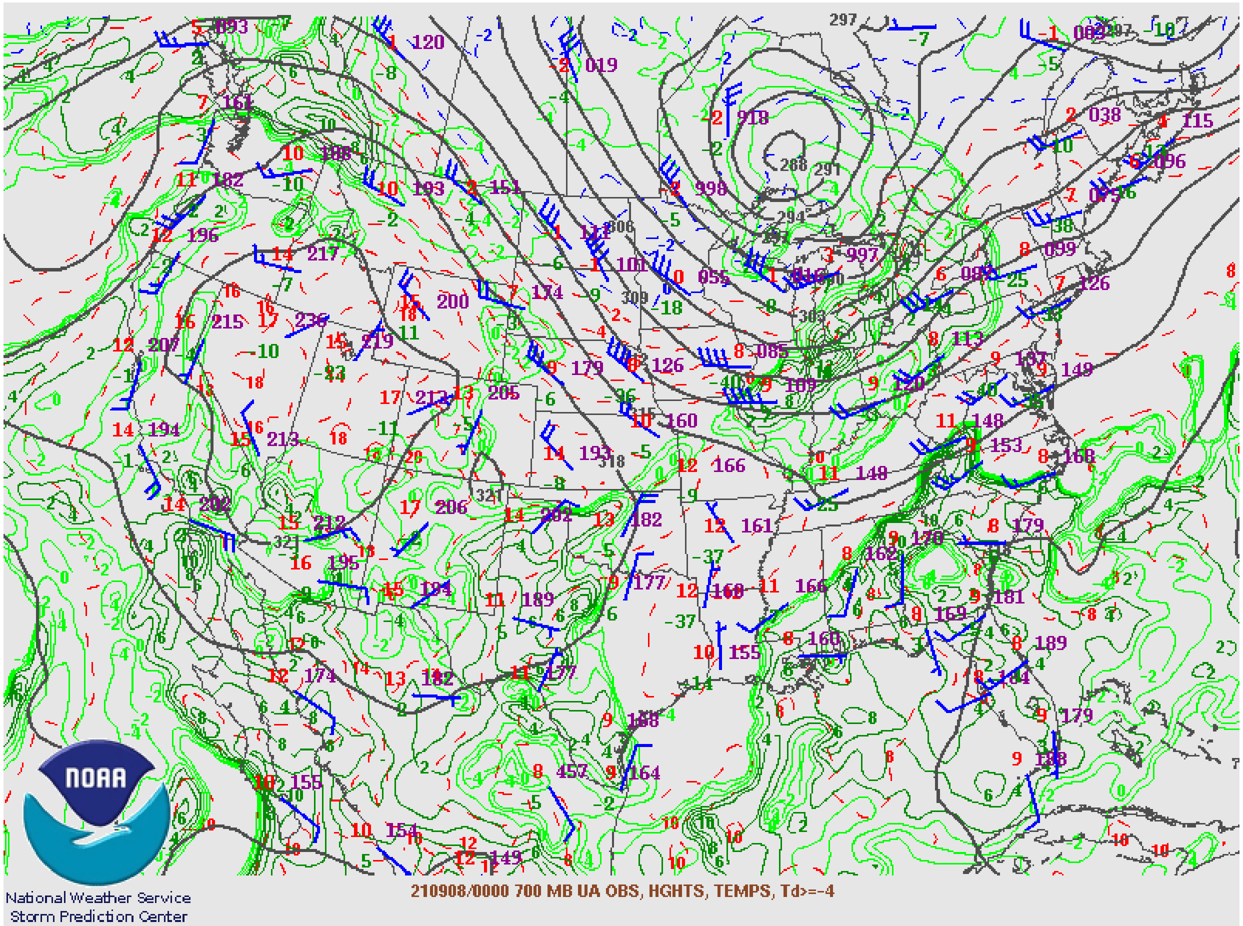

Figure 124. 700-mb map valid at 00:00 UTC on September 8, 2021 (16:00 PST on September 7, 2021). High pressure aloft over central and eastern Nevada allowed wildfire smoke to be transported into Clark County, NV.

4.7.4 Surface Impacts

The presence of surface-level wildfire smoke during the exclusion date is supported by the visibility-reduction observed when comparing the visibility conditions on September 7 (Figure 125) to the conditions on the exclusion date of September 8 (Figure 126). Local and regional smoke from the actively burning fires was visible in Clark County on September 8 at 09:00 LST (09:00 PST), when ozone photochemical production typically starts to accelerate. This is consistent with the KLAS hourly METAR reports for September 8, 2021, (Table 26) which note conditions were 'HAZY' due in part to wildfire smoke impacting Clark County. The METAR reports also show that wind speeds were low at KLAS,[26] resulting in stagnant conditions favorable to smoke-induced ozone production.

[26] Available from Iowa Environmental Mesonet, accessed Sept 7, 2023. https://mesonet.agron.iastate.edu/request/download.phtml?network=NV_ASOS.

Figure 125. Camera images showing the north (top left), south (bottom left), northeast (top right), and northwest (bottom right) coordinal directions. taken from the M Resort Hotel in Clark County, NV, on September 7, 2021, at 09:00 LST.

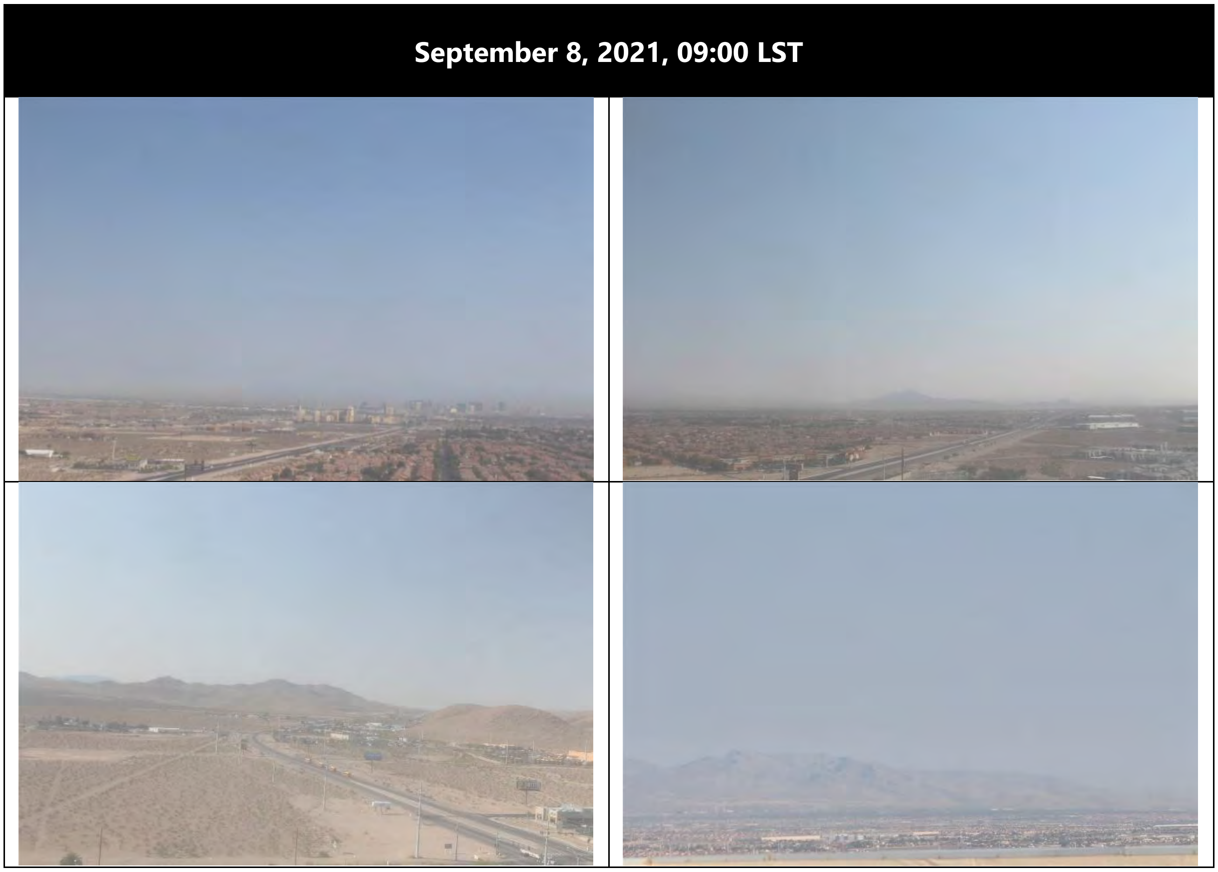

Figure 126. Camera images showing the north (top left), south (bottom left), northeast (top right), and northwest (bottom right) coordinal directions taken from the M Resort Hotel in Clark County, NV, on September 8, 2021, at 09:00 LST.

Table 26. KLAS hourly METAR reports for September 8, 2021, between approximately 21:00-23:00 UTC (13:00-15:00). During this period, the METAR remarks noted "HAZY" sky conditions.

September 8 Time (UTC)	September 8 Time (PST)	Wind Direction / Speed	Temp / Dew Point (C)	Sea Level Pressure (hPa)	Sky Conditions
20:56	12:56	VRB / 03 KT	41 / 06	1009.4	HAZY
21:56	13:56	VRB / 05 KT	41 / 06	1008.7	HAZY
22:56	14:56	000 / 00 KT	41 / 06	1008.1	HAZY

The presence of surface level wildfire smoke on September 8 is also indicated by enhanced ground-level $PM_{2.5}$, CO, and NO_2 concentrations. $PM_{2.5}$ concentrations compared to the diurnal 10th-90th percentile $PM_{2.5}$ concentration (Figure 127) shows hourly $PM_{2.5}$ concentrations exceeded the diurnal 90th percentile $PM_{2.5}$ concentrations at both sites on September 8.

Hourly CO concentrations are shown in Figure 128 with the 10th-90th percentile diurnal concentration, calculated from 2017-2021, at two nearby sites (Palo Verde and Walter Johnson sites do not have CO or NO_2 monitors). CO concentrations exceeded the 90th percentile concentration on September 7, the evening prior to the exclusion date and on the morning of September 8. Concurrently, NO_2 concentrations in Clark County were enhanced above the 90th percentile diurnal concentration on the night prior and morning of the exclusion date (Figure 129).

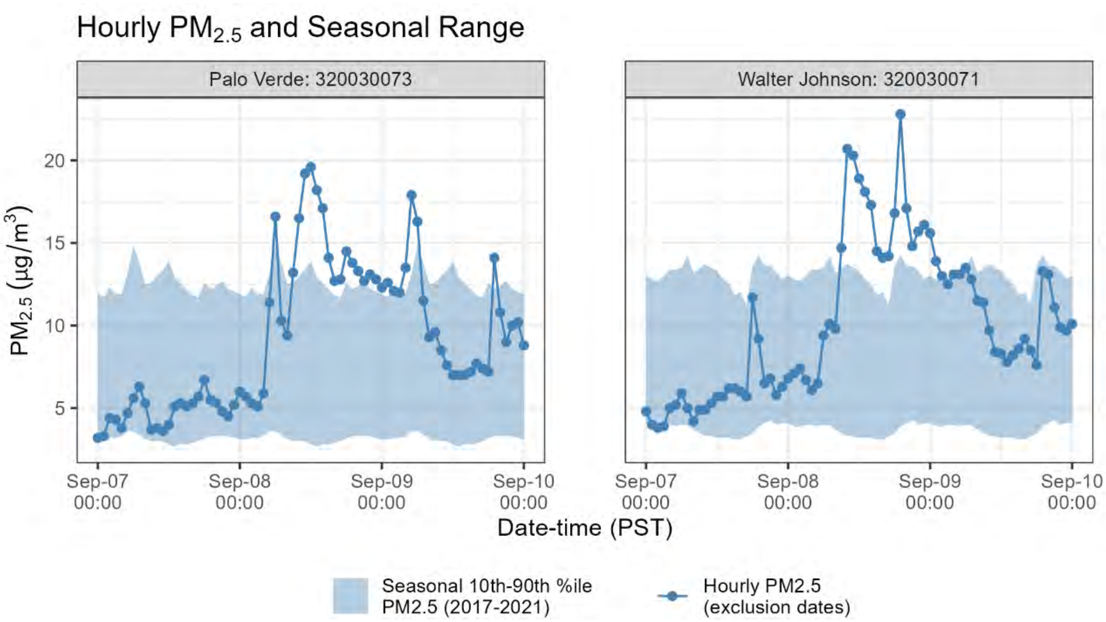

Figure 127. Hourly $PM_{2.5}$ measurements overlaid on the 10th-90th percentile diurnal concentration at a subset of event-affected measurement sites that measure $PM_{2.5}$ concentrations. The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021.

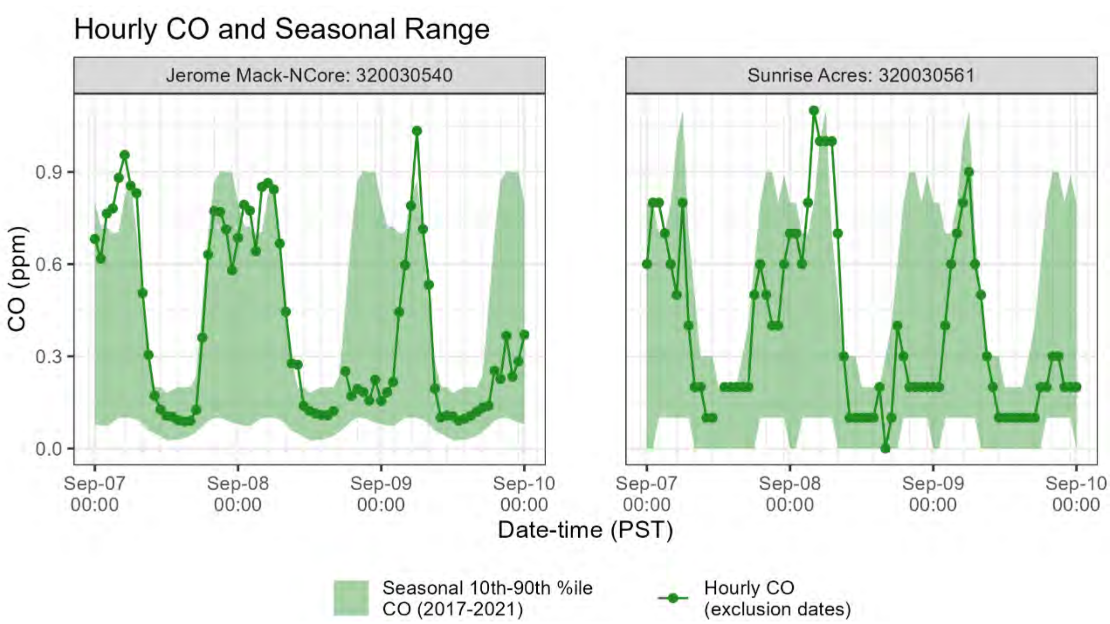

Figure 128. Hourly CO measurements overlaid on the 10th-90th percentile diurnal concentration at Clark County sites that measure CO. The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021.

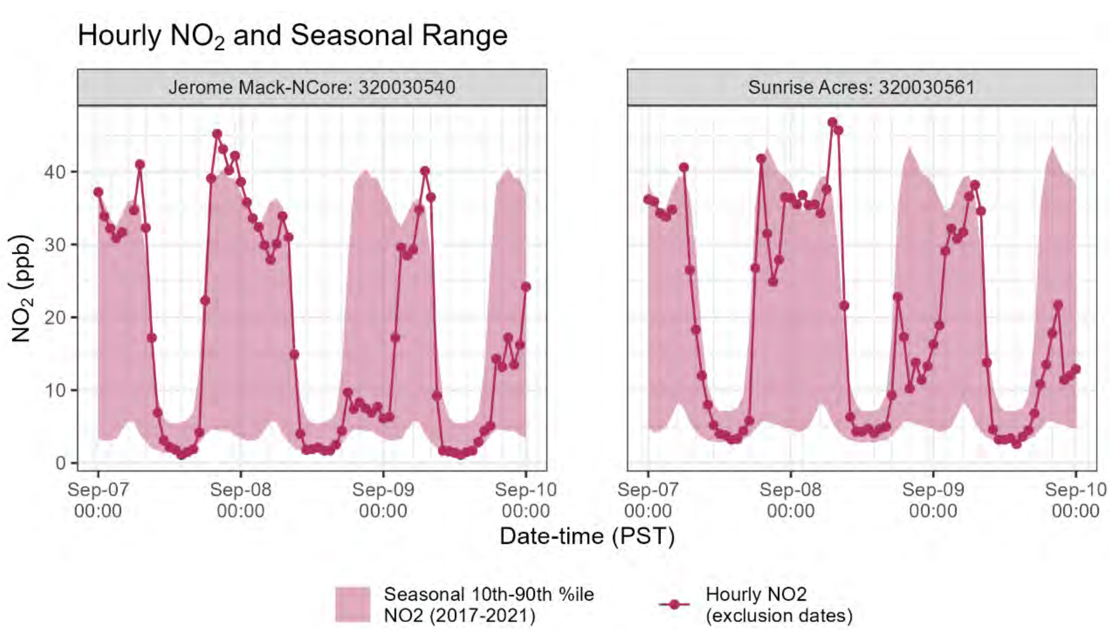

Figure 129. Hourly NO_2 measurements overlaid on the 10th-90th percentile diurnal concentration at Clark County sites that measure NO_2. The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021.

The ratio of $PM_{2.5}$-to-PM_{10} concentrations was also examined to determine if wildfire smoke entered Clark County on or before the exclusion dates. Increases in this ratio are indicative of wildfire smoke.

Figure 130 shows a time series of the ratio of $PM_{2.5}$-to-PM_{10} concentrations from September 7 through September 10, compared to the ozone season mean and 5th-95th percentile range for available data between 2017-2021 at the Palo Verde and Walter Johnson monitoring sites. The ratios show a sharp increase to above the 95th percentile during the late morning and early afternoon of September 8. A similar pattern is present at many of the non-affected sites (Figure 131), indicating that $PM_{2.5}$ was enhanced throughout the Las Vegas Valley. These observations are consistent with the $PM_{2.5}$, CO, and NO_2 enhancements that occurred on September 7 and 8, again suggesting that wildfire smoke entered the Clark County area on September 7 and lingered through September 8, influencing the atypical ozone event that occurred on September 8.

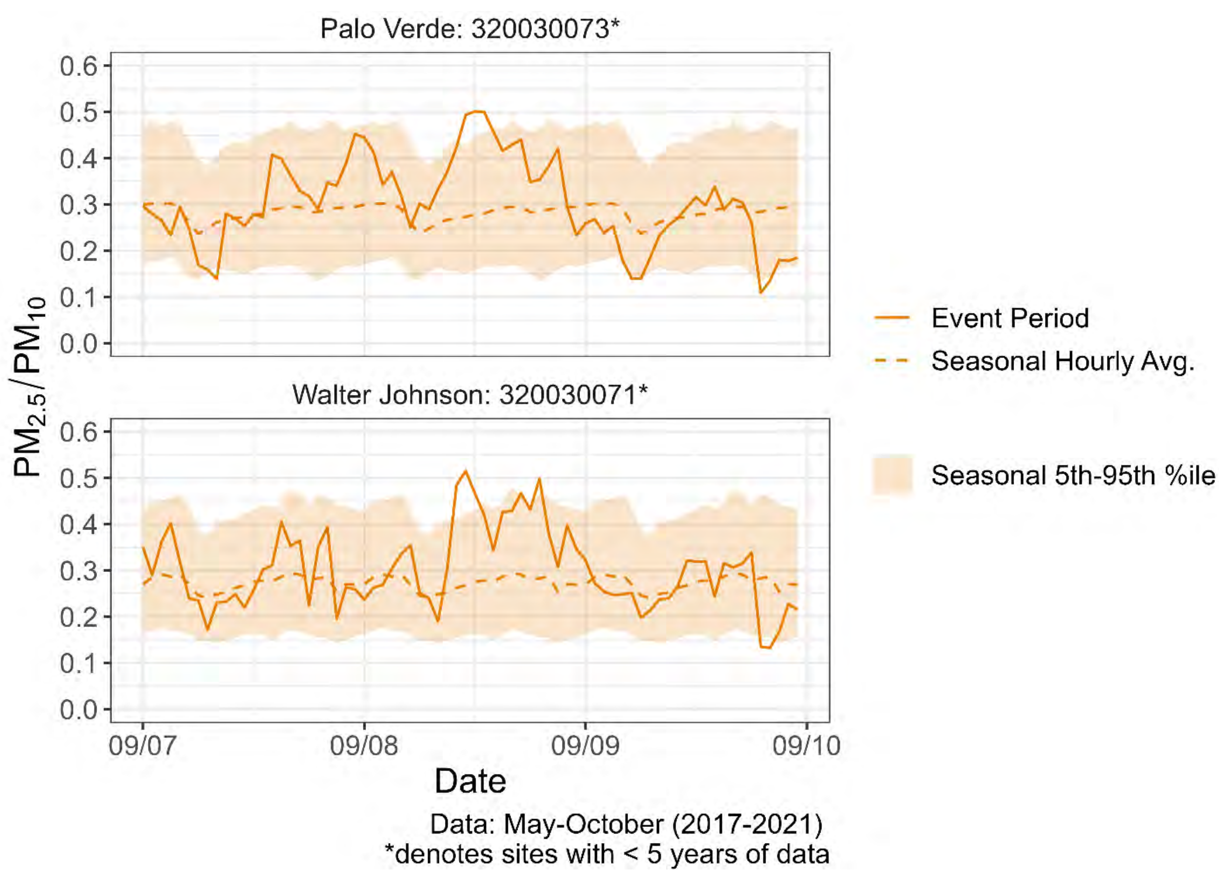

Figure 130. Ratio of $PM_{2.5}$-to-PM_{10} concentrations at the Palo Verde (top) and Walter Johnson (bottom) sites before and during the September 9 event period. The 5-yr average $PM_{2.5}$-to-PM_{10} diurnal ratio is displayed as a dotted line, and the 5th-95th percentile range is shown as a shaded ribbon. The 5th-95th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021.

Figure 131. Ratio of $PM_{2.5}$-to-PM_{10} concentrations at the non-affected sites before and during the September 9 event period. The 5-yr average $PM_{2.5}$-to-PM_{10} diurnal ratio is displayed as a dotted line, and the 5th-95th percentile range is shown as a shaded ribbon. The 5th-95th percentile concentration is calculated across the ozone production season (May-October) of 2017-2021.

4.7.5 Event Statistics

Table 27 summarizes the daily measurements of ozone, $PM_{2.5}$, CO, and NO_2 concentrations on the exclusion day, as well as the percentile rank of the observation compared to the previous five years of data (2017-2021). On September 8, 2021, ozone MDA8 measurements were above the 96th percentile, and 24-hr average $PM_{2.5}$ measurements were above the 90th percentile.

The 1-hr daily maximum CO and NO_2 concentrations measured at nearby sites show that both pollutants were somewhat higher than the typical ozone season values in Clark County, Nevada. CO 1-hr daily maximum measurements ranged from 864-1,100 ppb, or the 76th-83rd percentile. NO_2 1-hr daily maximum observations ranged from 38.6 to 46.8 ppb, or the 70th-87th percentile.

Table 27. Percentile of pollutant measurements on the exclusion day compared with most recent five years (2017-2021). The percentile rank is calculated across the ozone production season (May 1-October 31) of 2017-2021. Data from nearby sites that were not identified for the exclusion event are shown in italics.

Date	Site Name	Site Code	Ozone		$PM_{2.5}$		CO		NO_2	
			Ozone MDA8 (ppb)	Percent Rank	$PM_{2.5}$ 24-hr Avg (µg/m^3)	Percent Rank	CO 1-hr Daily Max (ppb)	Percent Rank	NO_2 1-hr Daily Max (ppb)	Percent Rank
9/8/2021	Walter Johnson	320030071	73	96	13.5	91.5*	--	--	--	--
9/8/2021	Palo Verde	320030073	71	97.3	12.4	90*	--	--	--	--
9/8/2021	*Jerome Mack-NCore*	*320030540*	--	--	--	--	*864*	*76.4*	*38.6*	*70.5*
9/8/2021	*Sunrise Acres*	*320030561*	--	--	--	--	*1100*	*83.6*	*46.8*	*87.1*

*Sites that have less than five years of data available for a given parameter: $PM_{2.5}$ measurements at the Walter Johnson and Palo Verde sites began in January 2020.

4.8 Request for Exclusion

The wildfire smoke events resulted in ozone measurements that are atypical, extreme, and nonrepresentative of past and future days for Clark County, NV. Appendix W to Part 51 states "control agencies have long expressed a need for consistency in the application of air quality models for regulatory purposes…the expanded requirements for models to cover even more complex problems have emphasized the need for period review and update of guidance on these techniques." Wildfire smoke events are one such complex problem, as wildfire season has extended and encompasses the summer months, which are also considered to be the ozone production season. Wildfire occurrence is wildly considered to be a stochastic natural phenomenon and is therefore inconsistent year-to-year. Downstream smoke impacts, including ozone formation, are not typical nor representative of the ambient conditions of Clark County, NV. The seven wildfire smoke events identified in this report are inconsistent with previous records and determined to be extreme, as indicated by:

- All site exceedances are above the 93rd percentile of historical ozone measurements.
- Multiple sites were affected during each event, including those that did not exceed regulatory standards.
- Significant smoke was identified from local or regional wildfire incidents.

Table 28 provides the evidence and exclusion narrative for each date.

Table 28. Evidence provided for each exclusion date.

Exclusion Date(s)	Event Summary
June 11-12, 2021	Local transport from the Sandy Valley Fire provided enhanced $PM_{2.5}$ concentrations during the flaming portion of the fire and enhanced gaseous pollutants during the smoldering portion of the fire. Transport is confirmed through dispersion modeling, meteorological analysis, and the timing of pollutant enhancements. Statistics show pollutant concentrations, including ozone, were atypical due to this event.
June 16-17, 2021	Regional transport of smoke from large wildfires in Arizona and New Mexico significantly enhanced $PM_{2.5}$ concentrations overnight prior to the exclusion days. Enhancements of co-emitted pollutants, camera images, and meteorological reports confirm the presence of smoke from these fires at the surface in Las Vegas. Dispersion modeling provides additional evidence that smoke was at the surface on the exclusion days. Statistics show pollutant concentrations, including ozone, were atypical due to this event.

Exclusion Date(s)	Event Summary
July 20, 2021	Regional transport of smoke from large wildfires in northern California and Oregon entered the Las Vegas area overnight on July 18 and 19 and coincided with an enhancement in $PM_{2.5}$ concentrations. Winds were calm-to-light and variable through July 20, allowing a build-up of pollutants and, therefore, atypical ozone production. Statistics show ozone concentrations were atypical and dispersion modeling confirms transport.
August 2-3, 2021	Regional transport of smoke from large fires in northern California was carried along a high-pressure system and caused increasingly hazy and smoky conditions over the course of the exclusion days. $PM_{2.5}$ concentrations increased above the 90th percentile, along with co-emitted pollutants and the $PM_{2.5}$-to-PM_{10} ratio, all of which are indicative of smoke impacts. Surface observations and camera images confirm the dispersion modeling showing smoke reaching the surface. Statistics show pollutant concentrations, including ozone, were atypical due to this event.
August 7, 2021	Regional transport of smoke from large wildfires in northern California showed an extreme enhancement in $PM_{2.5}$ concentrations on the exclusion day. Dispersion modeling confirms transport and enhancement in surface pollutants, and camera images and satellite imagery provide additional evidence that smoke was transported into the Clark County area. Statistics show pollutant concentrations, including ozone, were atypical due to this event.
August 19, 2021	Regional transport of smoke from multiple large wildfires across the western U.S. showed an extreme enhancement in $PM_{2.5}$ concentrations overnight on August 18-19. Dispersion modeling confirms transport, and meteorological data plus enhanced coincident pollutant concentrations confirm smoke in the Clark County area. Statistics show pollutant concentrations, including ozone, were atypical due to this event.
September 8, 2021	Regional transport of smoke from multiple large wildfires across the western U.S. coincides with enhanced $PM_{2.5}$ concentrations above the 90th percentile on the exclusion day, along with CO concentrations. Camera images confirm smoke at the surface, and dispersion modeling confirms transport of smoke from wildfires throughout the western U.S. Statistics show pollutant concentrations, including ozone, were atypical due to this event.

Based on the evidence provided, we formally request exclusion of the following dates in the base and projected ozone design values.

5. 2022 Ozone Technical Supporting Documents

The U.S. Environmental Protection Agency (EPA) published the memo "Clarification Memo on Additional Methods, Determinations, and Analyses to Modify Air Quality Data Beyond Exceptional Events," which illustrates cases where air quality data may be modified for certain regulatory determinations, actions, and analysis. The document defines cases where a request to exclude data can be made through the Exceptional Events Rule, such as when a National Ambient Air Quality Standard (NAAQS) design value is recalculated in EPA's Air Quality System (AQS) using modified data to determine attainment. The document also defines additional analyses that are not covered in the Exceptional Events Rule, where submitting modified data may be appropriate. These additional cases are defined as conditions where ambient air quality data may have been "influenced by an atypical, extreme or unrepresentative event." The Clark County Department of Environment & Sustainability (DES) is submitting a request to exclude data on this basis for the following case explicitly defined in the document: "Estimating base and future-year design values ozone SIP attainment demonstrations," as a part of DES' State Implementation Plan (SIP).

The EPA document states that monitoring data could qualify for exclusion if "[A]mbient data are not representative to characterize background or base period concentrations in accordance with the *Guideline,*" in reference to *Guideline on Air Quality Models* (40 CFR Part 51, Appendix W). Extreme wildfire events are increasingly prevalent in the western U.S., resulting in increased smoke impacts. Clark County, Nevada, was impacted by smoke from regional wildfires in the western U.S. in the summer of 2022 (**Table 29**). Following atypical smoke intrusions, high ozone concentrations were measured as a result of direct transport and secondary photochemical processes.

As stated in the memo, EPA or the appropriate reviewing authority will determine whether the air agency—in this case, Clark County DES—has appropriately documented and justified the data exclusion and/or adjustment when it acts on a SIP submission. The following documentation is provided to demonstrate that four local and regional wildfire smoke events in the period of June-September 2022 meet the criteria as defined in the document and guidance. This evidence is included as part of Clark County's request to exclude these data from base and future-year design values as a part of their SIP.

Table 29. Summary of events requested for exclusion from ozone SIP base and future-year design values.

Event Date	Event Ozone Concentration Percentile	Sites Exceeded During Event	Type of Event
June 16, 2022	95th – 97th	*(2)* Joe Neal and Paul Meyer	Regional Smoke
July 17, 2022	98th – 99.7th	*(5)* Green Valley, Garrett Jr. High, Jerome Mack, and Liberty High School	Regional Smoke
July 28-29, 2022	98th – 99.9th	*(6)* Joe Neal, Liberty High School, Mountains Edge Park, Palo Verde, Paul Meyer, and Walter Johnson	Regional Smoke
September 1-2, 2022	97th – 98th	*(1)* Paul Meyer	Regional Smoke

For each requested exclusion date(s), we present evidence that the ozone exceedance at each affected site in Clark County was impacted by regional wildfire smoke. Each subsequent section for the 2022 requested exclusion date(s) includes the following details:

- Ozone concentrations on, before, and after the exceedance date;
- A list of all wildfires that produced substantial smoke and impacted Clark County;
- Descriptions of transport of that smoke into Clark County, via meteorological analysis, dispersion modeling, and satellite data;
- Other air quality observations and associated statistics that coincide with the high ozone events.

5.1 June 16, 2022

5.1.1 Event Summary

An ozone event took place on June 16, 2022, in Clark County, Nevada, where the maximum daily 8-hr average (MDA8) ozone concentration was greater than 70 ppb at two monitoring site locations: 72 ppb at the Joe Neal site, and 71 ppb at the Paul Meyer site. The Spring Mountain (SM) Youth Camp monitoring site also experienced an MDA8 value of 72 ppb; it is outside of the Las Vegas Valley and not significant for the design value assessments, however, is indicative of a wide-spread regional ozone event. All sites within the Las Vegas Valley experienced MDA8 values on June 16 between 64 and 70 ppb, with an average MDA8 of 68 ppb. Regional wildfire smoke from eight fires within the U.S. and a fire in Baja, Mexico is suspected to have contributed to the NAAQS exceedances on this day. Major evidence includes ozone enhancement at background measurement sites such as SM, HMS smoke detection, enhanced ground-level acetaldehyde concentrations, and back trajectory analysis. This combination of evidence suggests that this is an unrepresentative event for base and future design value ozone assessments.

Time series graphs showing hourly ozone concentrations on June 15-19, the points that exceeded the seasonal means (calculated using data from May 1-October 31, 2017-2021), and the 10th-90th percentiles at each affected site are shown in **Figure 132**. After the typical diurnal peak near 12:00 PST, hourly ozone concentrations remained enhanced during the typical diurnal minimum, exceeding the 90th percentile between 14:00 to 20:00 PST and not returning to typical concentrations overnight. This enhancement of ozone concentrations later in the day than usual impacted the MDA8 concentrations by keeping ozone concentrations high and increasing the maximum 8-hr average value. The MDA8 value for each exceedance site was between 11:00 to 18:00 PST at each exceedance site.

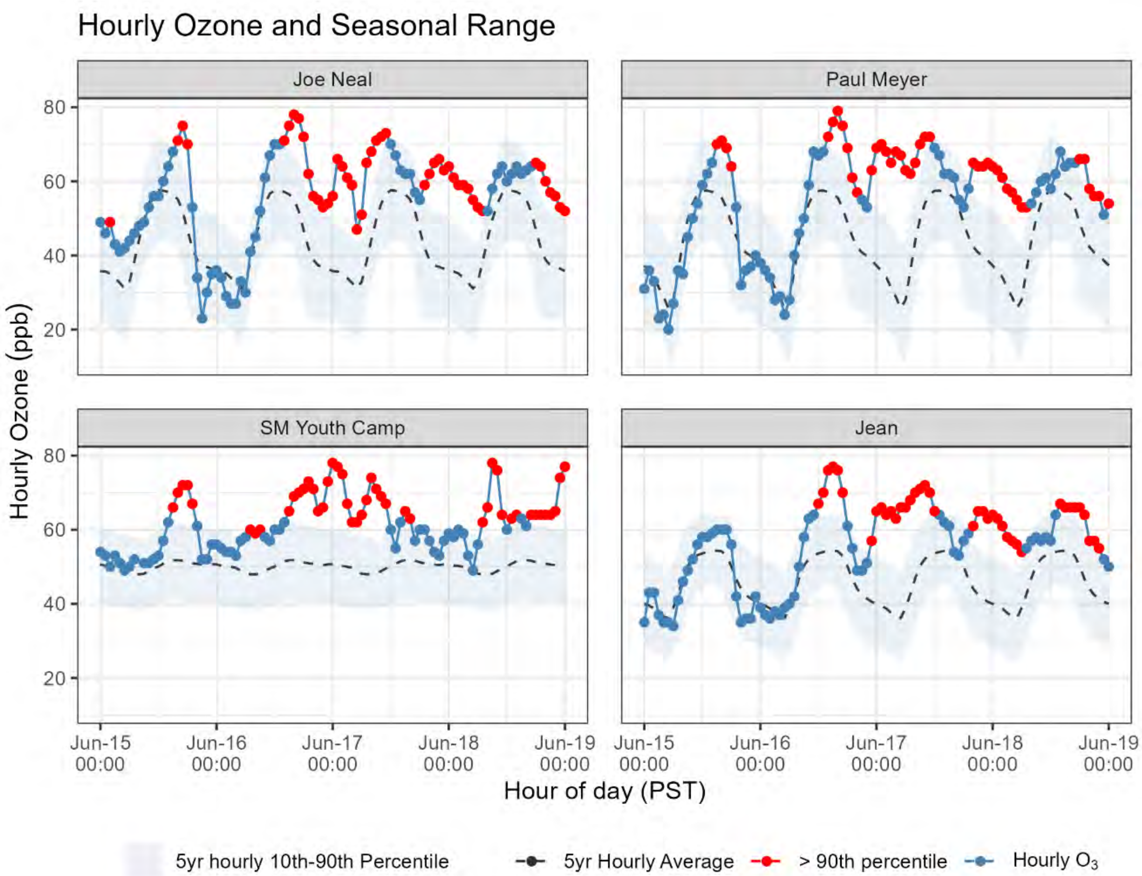

Figure 132. Hourly ozone concentrations (ppb) across June 15-19, 2022, compared to 5-yr ozone season (May 1-October 31) hourly means and 10th-90th percentiles. Note: data collection at the SM Youth Camp did not begin until 2019.

The Joe Neal and Paul Meyer sites are located near the Las Vegas city center, with Joe Neal to the northwest and Paul Meyer to the southwest. The SM Youth Camp and Jean sites, also included in Figure 132, are located far from the city center and thus give insight into regional background levels. The SM Youth Camp site is far northwest of the city center in the Spring Mountain range at a high elevation, and the Jean site is far southwest of the city at a low elevation near the Mojave Desert and California border. The similarities in the trends between the city sites (Joe Neal and Paul Meyer) compared to the background sites (SM Youth Camp and Jean) provide evidence that this event was more likely due to regional influences such as wildfire smoke, rather than only from locally generated emissions.

5.1.2 Identification of Wildfires

Figure 133 shows HMS maps that display the progression of smoke across the United States between June 14 and June 17, 2022, including the event date of June 16. On June 14, distinct eastward transport of smoke from fires in Arizona and New Mexico is visible. Beginning on June 15, this eastward transport stagnates and smoke spreads westward and drifts over Clark County, as shown between the June 16 and 17 HMS images. HMS smoke maps are created using visible satellite imagery from Geostationary Operational Environmental Satellites (GOES). Visible imagery is only available during the sunlit part of the GOES orbit; therefore, smoke movement during nighttime hours is inferred between the daylight-generated smoke maps. Additionally, a fire in north-central Baja Mexico is shown on the maps for June 14 and 15; the smoke from this fire was then mixed into the overall regional smoke on later dates. There is a clear progression of smoke into Las Vegas from the south and east between June 16 and June 17, coinciding with the unusually high ozone concentrations in the late afternoon and evening on June 16 at both urban and background sites in the Las Vegas area.

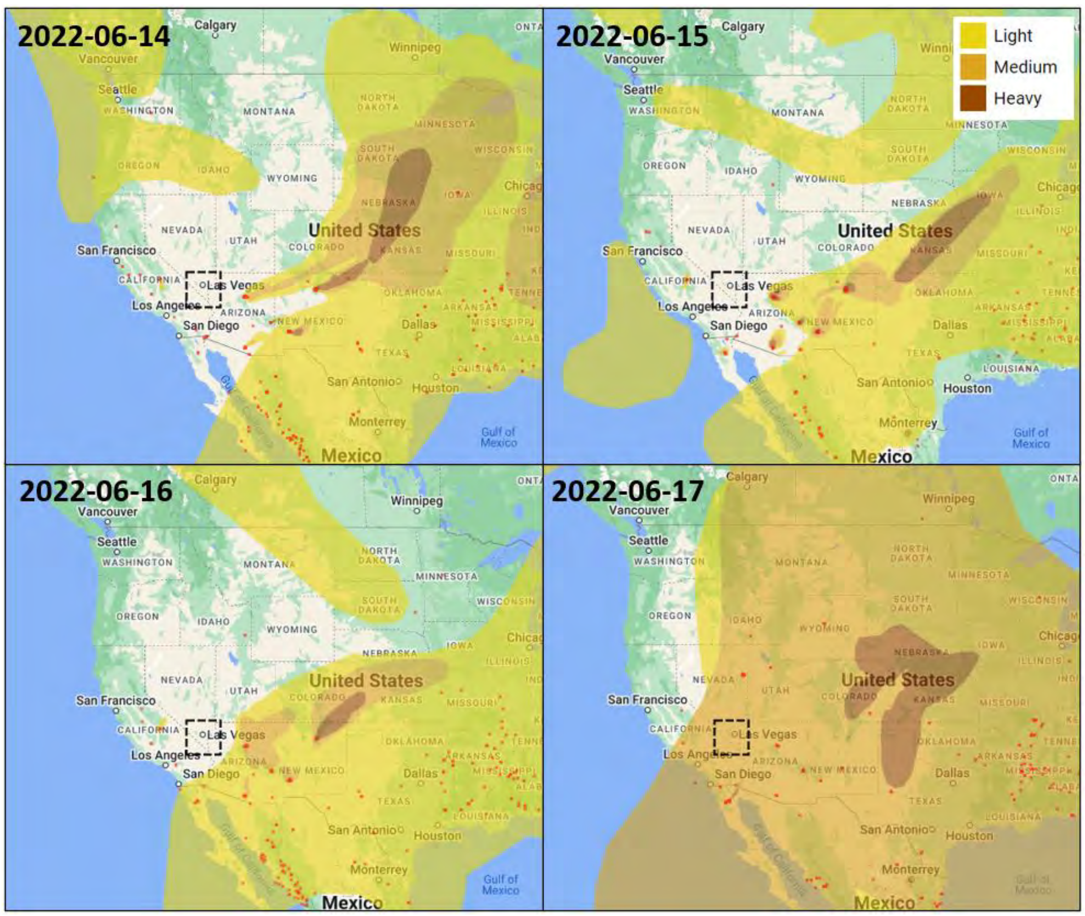

Figure 133. HMS smoke maps for June 14-17, 2022, showing smoke transport and qualitative smoke density. Clark County, NV, is enclosed by a dashed, black box on each map.

Numerous wildfires in Arizona, New Mexico, and Baja Mexico were active on and before June 16, 2022, the exclusion day, which contributed to regional smoke as shown in the HMS images from Figure 133. Eight major wildfires in the U.S. with significant emissions that contributed to the regional smoke were identified: the Hermits Peak, Calf Canyon, Black, Tonto Canyon, Contreras, Haywire, Pipeline, and Fish Fires. Another fire in north-central Baja Mexico was identified as a likely contributor of wildfire smoke to the area. We were unable to find details on this fire, but have provided general information based on HMS smoke and fire records.

Table 30 presents the state location, total acres within the fire perimeter, actively burning acres on the exclusion day, and the start and containment dates for each fire based on data from InciWeb and Wikipedia. For the Baja fire in Mexico, we estimated the start and containment dates, as well as the first size based on HMS fire hotspot data. For fires in the U.S., perimeters for each fire in relation to Clark County are shown in Figure 134. A zoomed in view of each fire is shown in Figure 135.

Table 30. Wildfires affecting Clark County on the exclusion day of June 16, 2022. The fire name, state location, total acreage, acres burned on or before the exclusion day, and the start and containment dates are included. Italicized data for the Baja fire in Mexico are estimated using HMS fire and smoke data.

Wildfire Name	State	Total Acres	Acres Burned on or Before June 16	Start Date	Containment Date
Hermits Peak	New Mexico	341,735	336,638 (June 16)[27]	April 6	Aug. 21
Calf Canyon	New Mexico	341,735	336,638 (June 16)[27]	April 9	Aug. 21
Black	New Mexico	325,136	320,971 (June 16)[28]	May 14	Nov. 18
Tonto Canyon	Arizona	9,264	8,884 (June 15)[29]	June 12	June 22
Contreras	Arizona	29,482	11,489 (June 15)[30]	June 11	July 4
Haywire	Arizona	5,575	5,372 (June 16)[31]	June 13	July 4
Pipeline	Arizona	26,532	24,815 (June 16)[32]	June 12	July 4
Fish	Arizona	3,704	1,900 (June 16)[33]	June 10	July 13
Baja Fire	*Baja, MX*	*1,000*	*7,000 (June 17)*	*June 11*	*June 21*

[27] https://en.wikipedia.org/wiki/Calf_Canyon/Hermits_Peak_Fire
[28] https://en.wikipedia.org/wiki/Black_Fire_(2022)
[29] https://inciweb.nwcg.gov/incident-maps-gallery/azcnf-tonto-canyon-fire
[30] https://inciweb.nwcg.gov/incident-maps-gallery/azppa-contreras-fire
[31] https://inciweb.nwcg.gov/incident-information/azcof-haywire-fire
[32] https://inciweb.nwcg.gov/incident-information/azcof-pipeline-fire
[33] https://inciweb.nwcg.gov/incident-publication/azasf-fish-fire/apachesitgreaves-national-forests-continue-responding-to-the-fish-fire

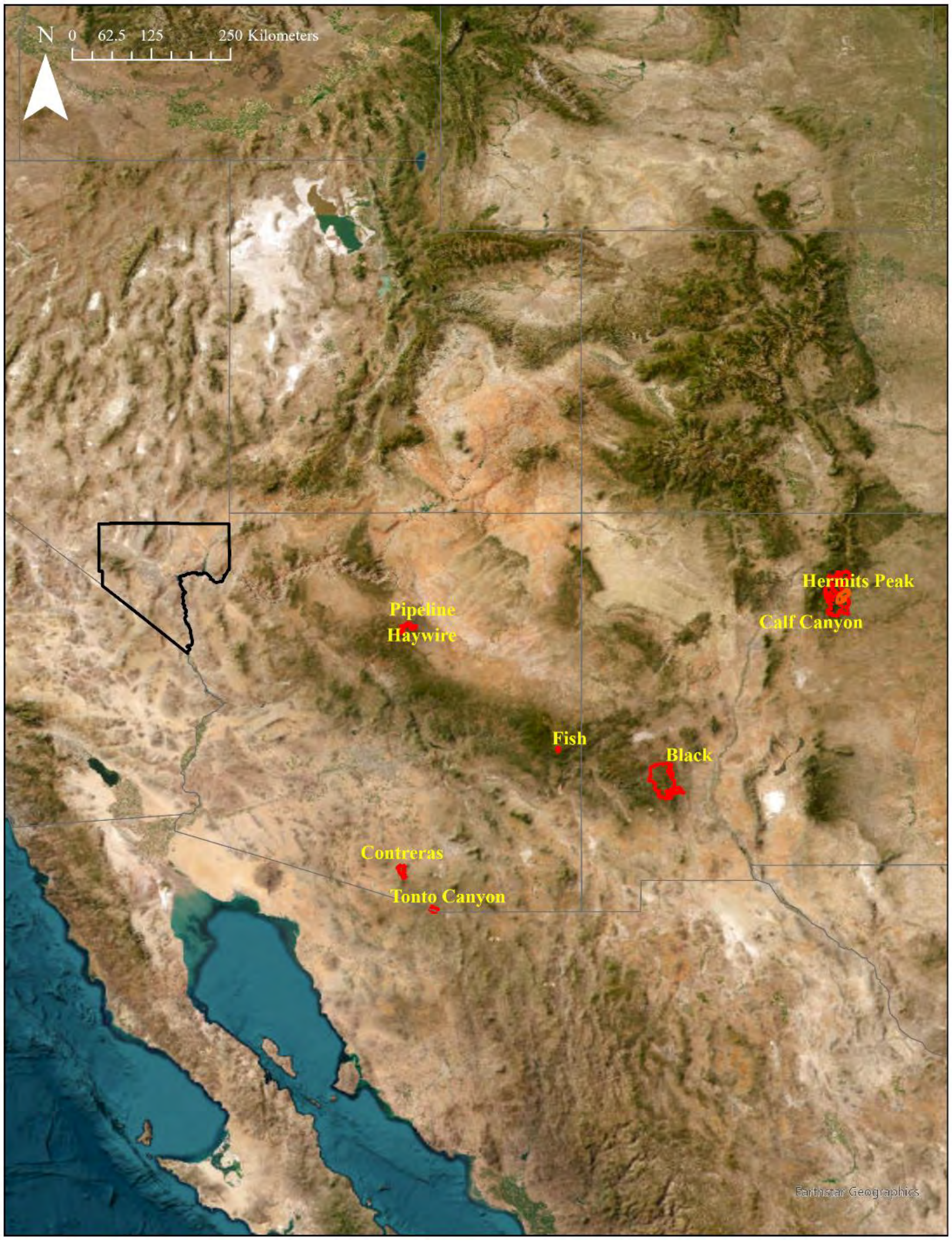

Figure 134. Final fire perimeters (red) for the eight active fire regions in the U.S. during the June 16, 2022, exclusion date in relation to Clark County (black perimeter).

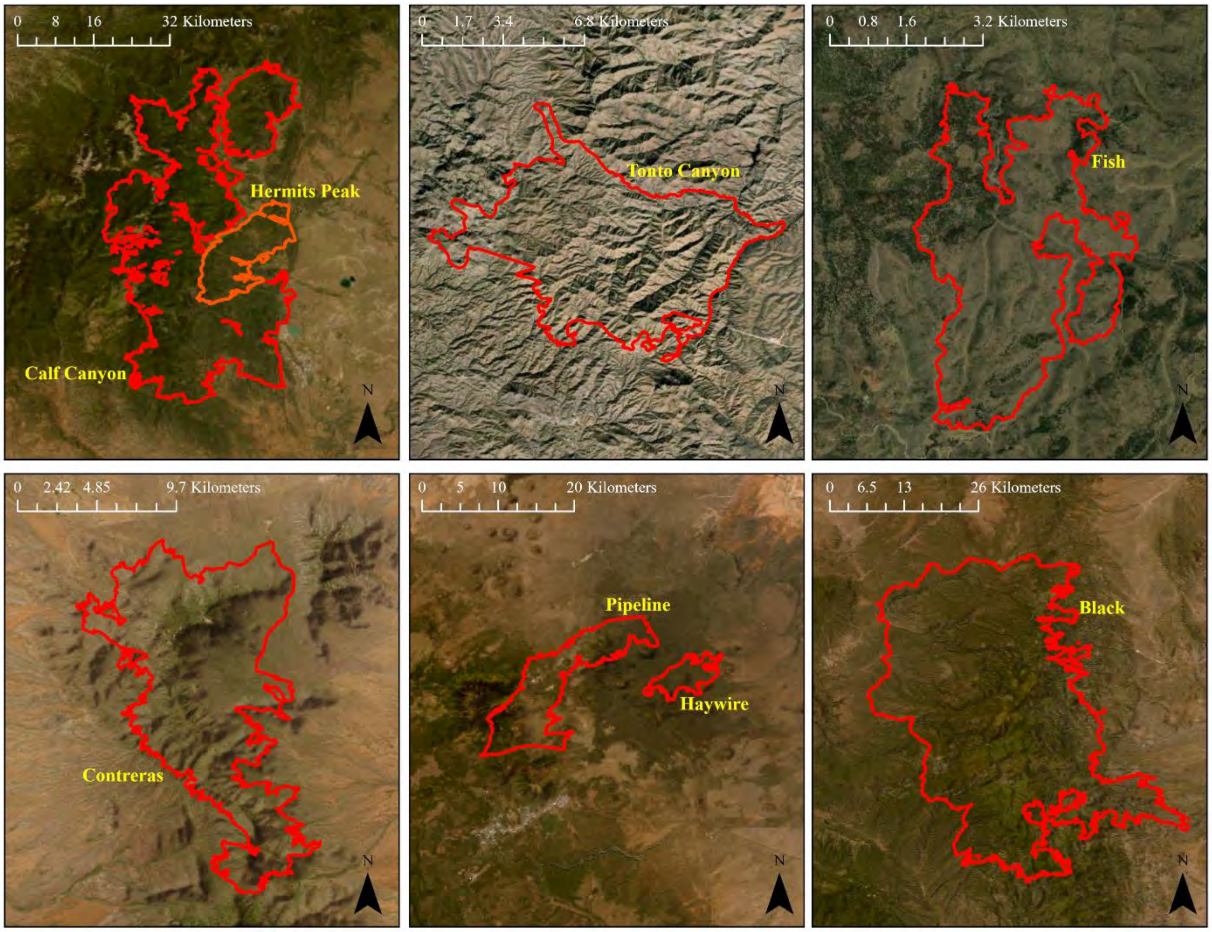

Figure 135. Final fire perimeters (red) for the eight active fire regions in the U.S. during the June 16, 2022, exclusion date.

5.1.3 Dispersion Modeling and Regional Analysis

To examine the effect of wildfire smoke in Clark County (as indicated by the HMS smoke maps shown in Section 5.1.2), we first determined the meteorological conditions on and before the June 16 event. We specifically focused on boundary layer dynamics to determine the depth of mixing and possibility of smoke mixing to the surface. We then used this information to model smoke via the Hybrid Single-Particle Lagrangian Integrated Trajectory (HYSPLIT) model and compare the results with independent data sources, including HMS and High-Resolution Rapid Refresh (HRRR) model data.

The planetary boundary layer (PBL) denotes the atmospheric layer closest to the surface, and the height of the PBL describes the vertical extent of surface air characteristics. Atmospheric soundings and PBL maps provide visualizations of the extent of vertical mixing in the lower troposphere. The two skew-T diagrams in Figure 136 show the vertical profile of the atmosphere on June 16 at 12:00 UTC (04:00 PST) and on June 17 at 00:00 UTC (June 16 at 16:00 PST). The two skew-T diagrams are characterized primarily by the removal of the near-surface temperature inversion from the 04:00 PST sounding to the 16:00 PST sounding on June 16, and the large mixing layer above the surface after the near-surface inversion had dissipated. The early morning near-surface temperature inversion, observed by the 04:00 PST sounding, likely prevented air aloft from mixing down into the lower troposphere. During the afternoon (16:00 PST) sounding, the temperature inversion was no longer active, allowing the air to be mixed down into the lower troposphere, as indicated by the temperature line following near the dry adiabatic lapse rate lines. This indicates that the lower PBL was well-mixed up to approximately 3,100 m above ground level (agl), at the same time ozone concentrations were remaining unusually high and smoke was likely being transported into the area. The North American Mesoscale Forecast System (NAM)-modeled PBL heights over Clark County on June 17 at 00:00 UTC (June 16 at 16:00 PST) roughly corresponds to the PBL heights shown by the sounding of the same time (Figure 137), providing independent verification. The NAM-modeled data map in Figure 137 shows PBL heights above 2 km in altitude in 1 km increments, with color contours starting at 1 km.

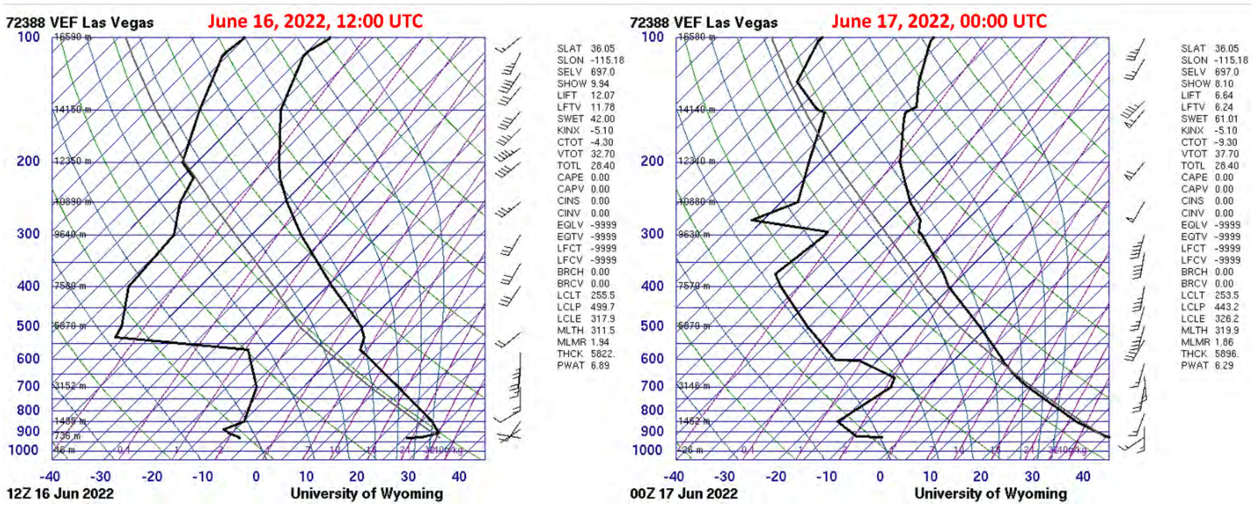

Figure 136. Skew-T soundings launched from the Las Vegas National Weather Service office on June 16, 2022, at 12:00 UTC (04:00 PST) (left), and June 17 at 00:00 UTC (June 16 at 16:00 PST) (right).

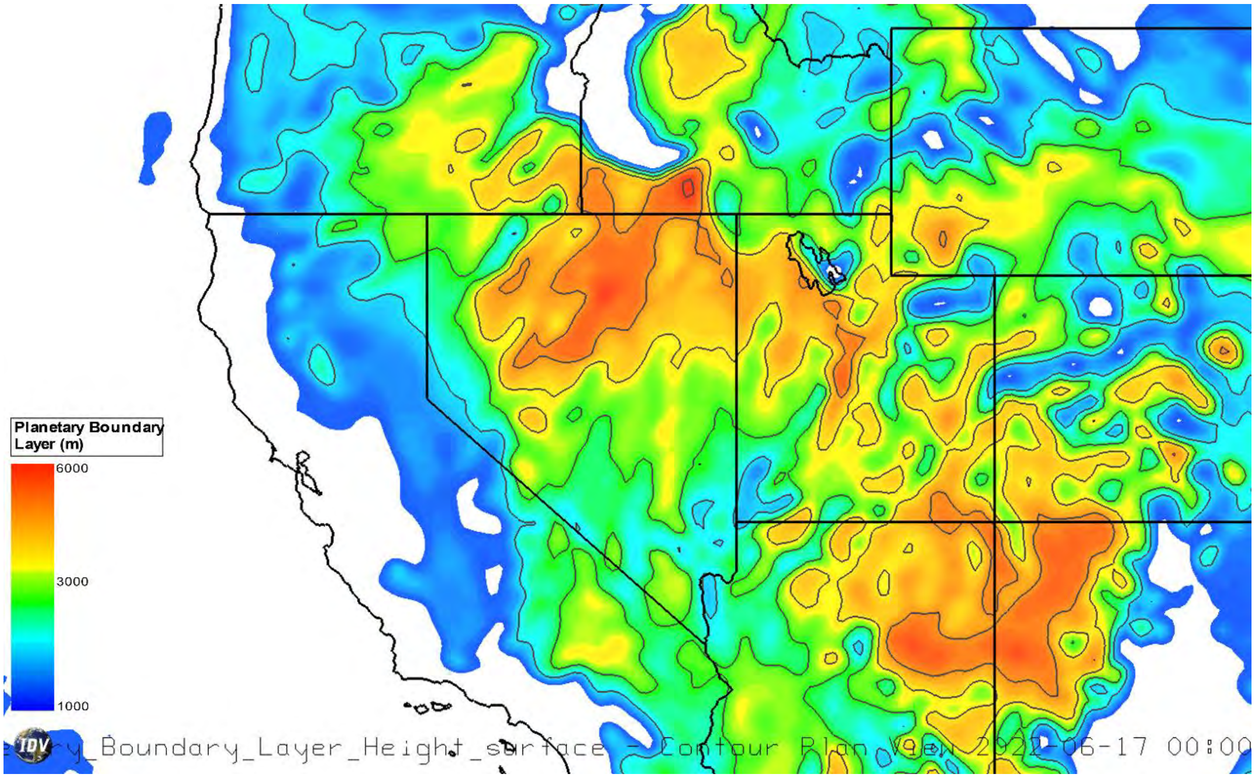

Figure 137. PBL height contour map based on the NAM model for June 17, 2022, at 00:00 UTC (June 16 at 16:00 PST). The gray lines denote PBL heights above 2 km in altitude in 1 km increments. Color contours begin at 1 km.

HYSPLIT dispersion modeling was performed from June 13 through June 16, 2022. Dispersion was initiated for June 13 at 19:00 PST from the eight identified active fires in the U.S. impacting the exclusion date and modeled through the exclusion date to simulate the smoke patterns seen in satellite imagery and HMS smoke data. We were not able to model smoke dispersion from the Baja fire in Mexico due to a lack of daily fire information (i.e., fire perimeters). Global Data Assimilation System (GDAS) data at 1.0° horizontal resolution was used for meteorological input. Output from the dispersion modeling has been integrated for 8-hr intervals over the period starting at 19:00 PST on June 15 and ending at 19:00 PST on June 16, including the afternoon and evening of June 16, when ozone concentrations were abnormally high and smoke intruded into the area. Smoke accumulation throughout the boundary layer at 0-3,700 m for this period is shown in Figure 138.

The HYSPLIT dispersion modeling shows that smoke from multiple fires in the U.S. produced a dense layer of smoke that blanketed the region east of Clark County, NV. The modeling results are consistent with the HMS smoke plume (shown in gray in Figure 138); HMS is an independent smoke identification database.

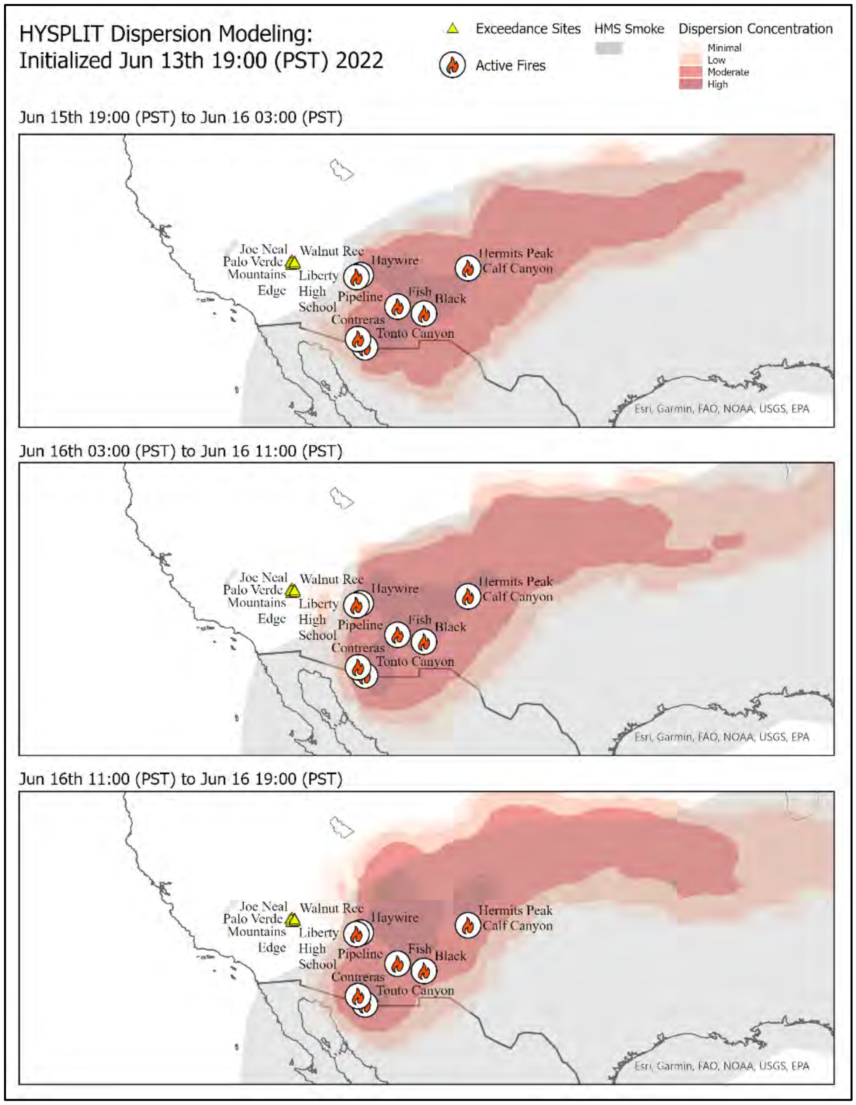

Figure 138. HYSPLIT dispersion modeling for seven large fires (labeled as "Active Fires") in New Mexico and Arizona on or before the exclusion date of July 16, 2022. GDAS 1.0° meteorological data was used, and dispersion was initiated on June 13, 2022, at 19:00 PST to model the regional smoke observed in satellite and HMS products. HMS smoke is shown in gray and qualitative concentrations of particulate matter are shown in shades of red. Accumulation of particulate matter is shown at 0-3,700 m for 8-hr periods between 19:00 PST on June 15 through 19:00 PST on June 16, 2022.

While the smoke plume was not directly over Clark County in the late afternoon on June 16, back trajectories shown in Figure 139 indicate that air was advected from the southwest and from the area of regional smoke in the afternoon on June 16, 2022. These HYSPLIT back trajectories were initialized on June 16 at 16:00 PST (00:00 UTC); i.e., during the middle of the MDA8 ozone period. Lower level (500 and 1,000 m) back trajectories show surface level transport from the direction of the regional smoke. Upper level (2,500 m) back trajectories show longer ranger transport from the Baja, Mexico fire direction. The upper-level trajectory would still be within a well-mixed boundary layer in Clark

County according to PBL height estimates. Back trajectories and dispersion modeling indicate that although the main plume remained to the east of Clark County, smokey air was likely advected into the region in the afternoon on June 16 from both the Arizona/New Mexico fires and the Baja fire in Mexico, which impacted ozone concentrations and kept them high outside of the typical diurnal profile. These results are consistent with the previous HMS evidence that shows the overall smoke plume was moving westward toward Clark County between June 16 and 17. Additionally, based on the boundary layer analysis, we suggest that smoke entering the area would have been well mixed with the surface.

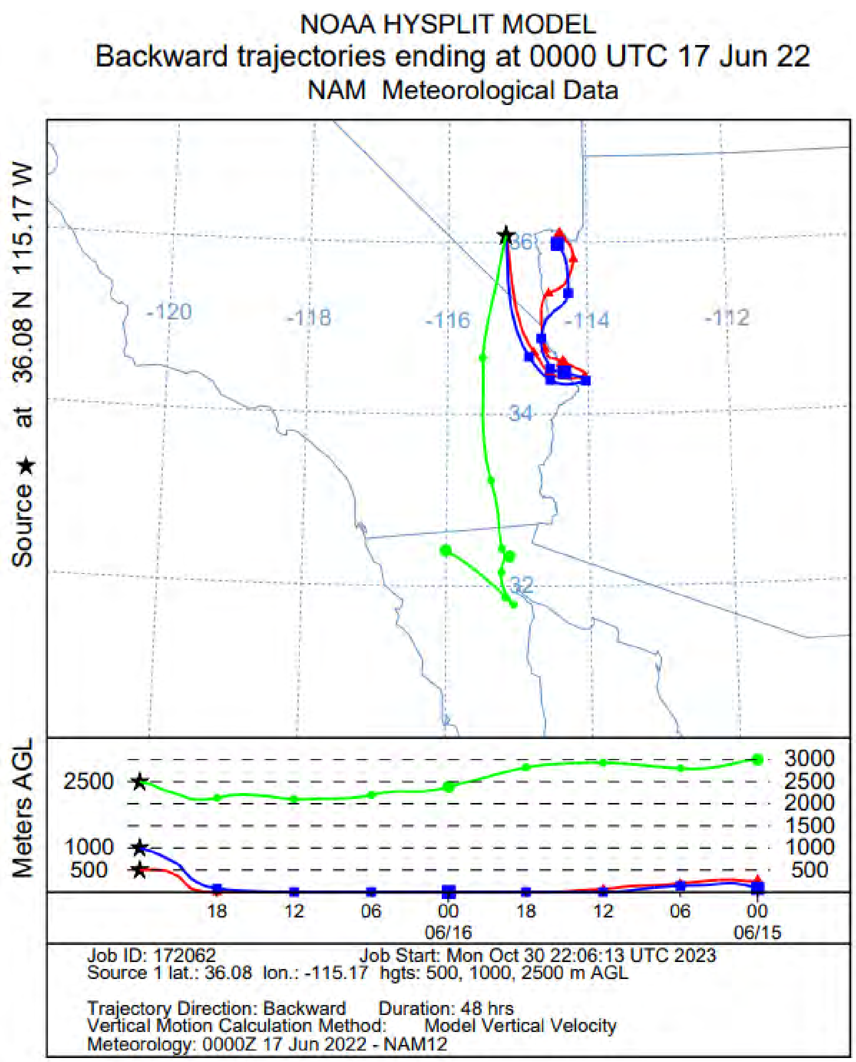

Figure 139. HYSPLIT back trajectory analysis initiated on June 16, 2022, at 16:00 PST (00:00 UTC) showing air advection into Clark County in the afternoon using NAM 12 km meteorological data. Back trajectory heights were modeled at 500, 1,000, and 2,500 m to show near-surface and synoptic flow.

Confirmation of this analysis is shown by the HRRR forecasts in Figure 140. The HRRR data is shown for June 16, 2022, at 11:00 and 15:00 PST. The HRRR data shows heavy levels of smoke being emitted from the New Mexico, Arizona, and Baja Mexico fires that were mixed into a regional plume of smoke. The plume of smoke over southern California can be traced back to the Baja fire in Mexico, which is shown to be directly impacting Clark County on June 16 during the MDA8 ozone period. The back trajectories shown previously also indicate nearly direct transport from the Baja fire area in Mexico to Clark County, similar to the HRRR results. Overall, the HRRR product shows low to medium levels of vertically integrated smoke from the fires in Baja, Mexico, Arizona, and New Mexico over the Clark County region in the afternoon on June 16.

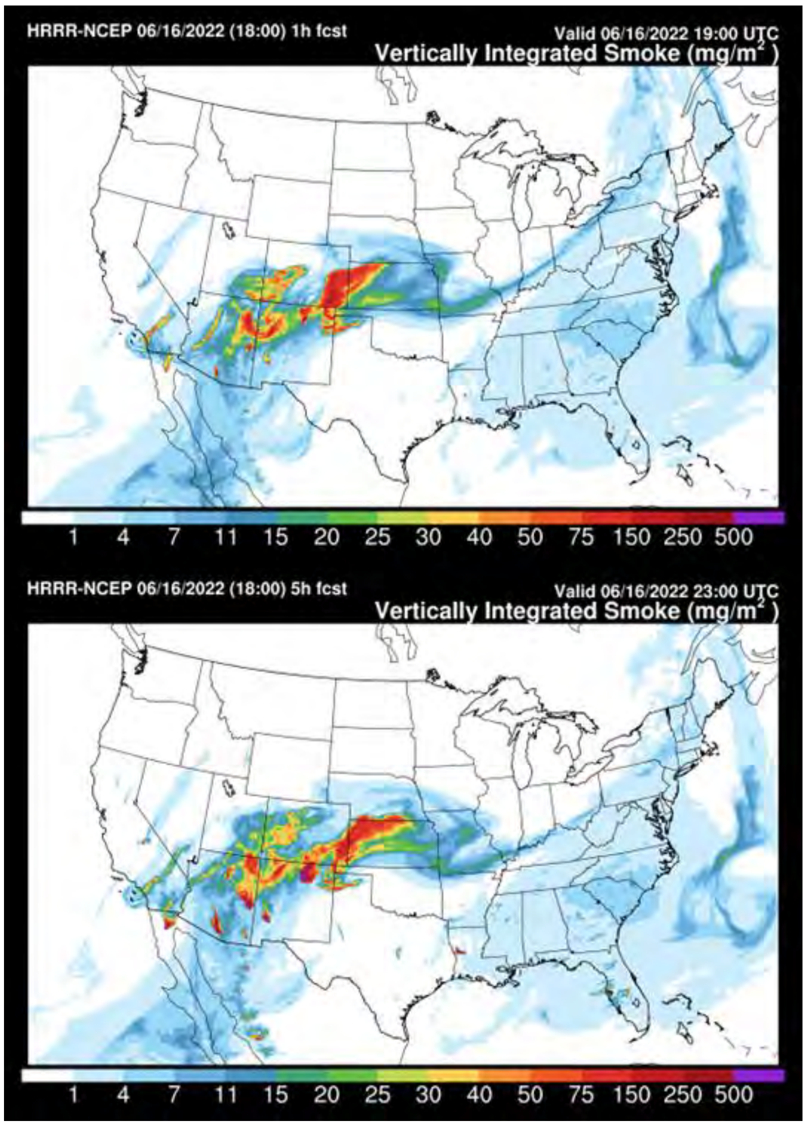

Figure 140. HRRR vertically integrated smoke forecast for June 16, 2022, at 11:00 PST and 15:00 PST.

5.1.4 Surface Impacts

Figure 141 and Figure 142 compare visibility conditions in the Las Vegas Valley before and during the exclusion date. Figure 141 shows visibility conditions at 15:00 PST on June 15, 2022, the day before the event. While the images captured on June 15 do show some reduction in visibility, the images captured at 15:00 PST on June 16 (Figure 142) do show more brown-tinted skies compared with June 15. This is consistent with a well-mixed boundary layer with smoke. Both Figure 141 and Figure 142 show the Sheep Mountain Range in the top left image and the La Madre Mountain in the bottom right image; both mountain ranges are less visible on June 16 than on June 15. The brown-tinted haze throughout the column, shown in the afternoon June 16 images compared to the afternoon June 15 images, is consistent with the narrative that smoke from the Arizona and New Mexico fires entered the Las Vegas area in the afternoon on June 16 and was well mixed in the column.

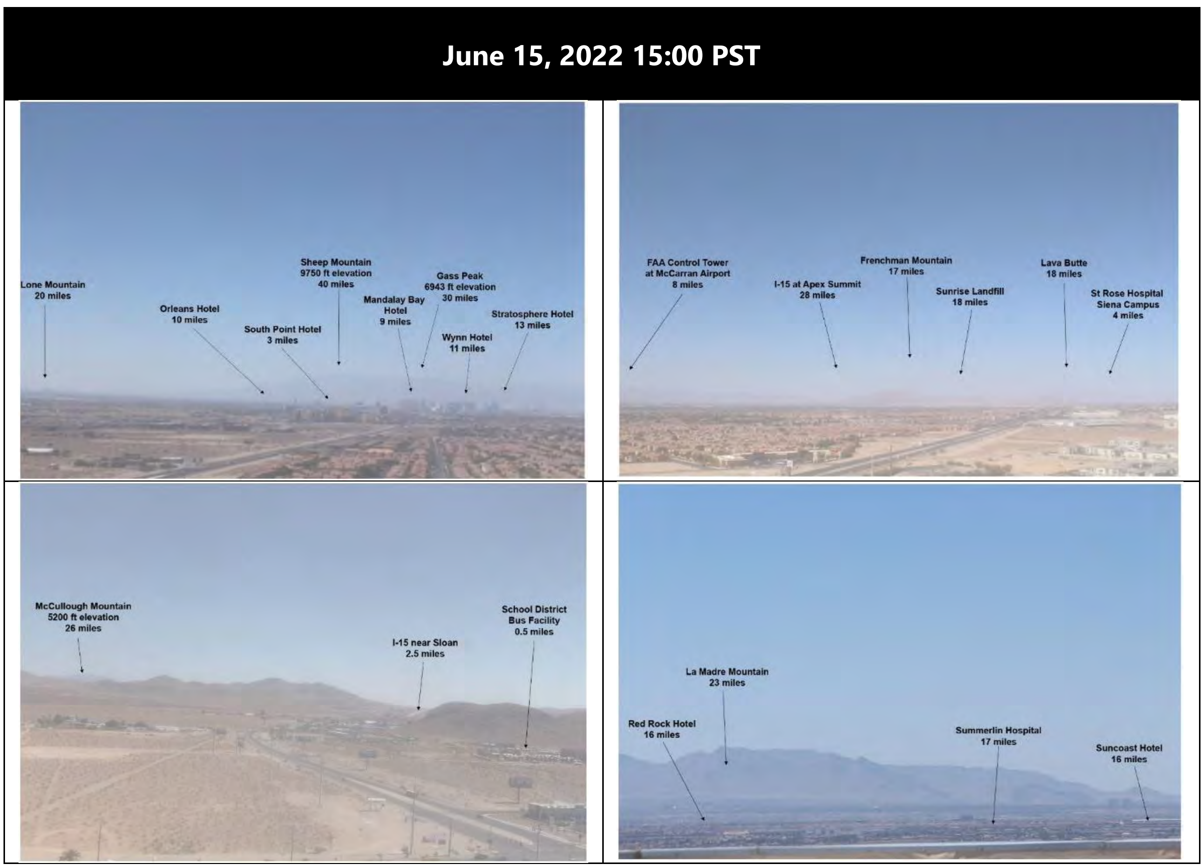

Figure 141. Camera images showing the north (top left), south (bottom left), northeast (top right), and northwest (bottom right) coordinal directions, taken from the M Resort Hotel in Clark County, NV, on June 15, 2022, at 15:00 PST.

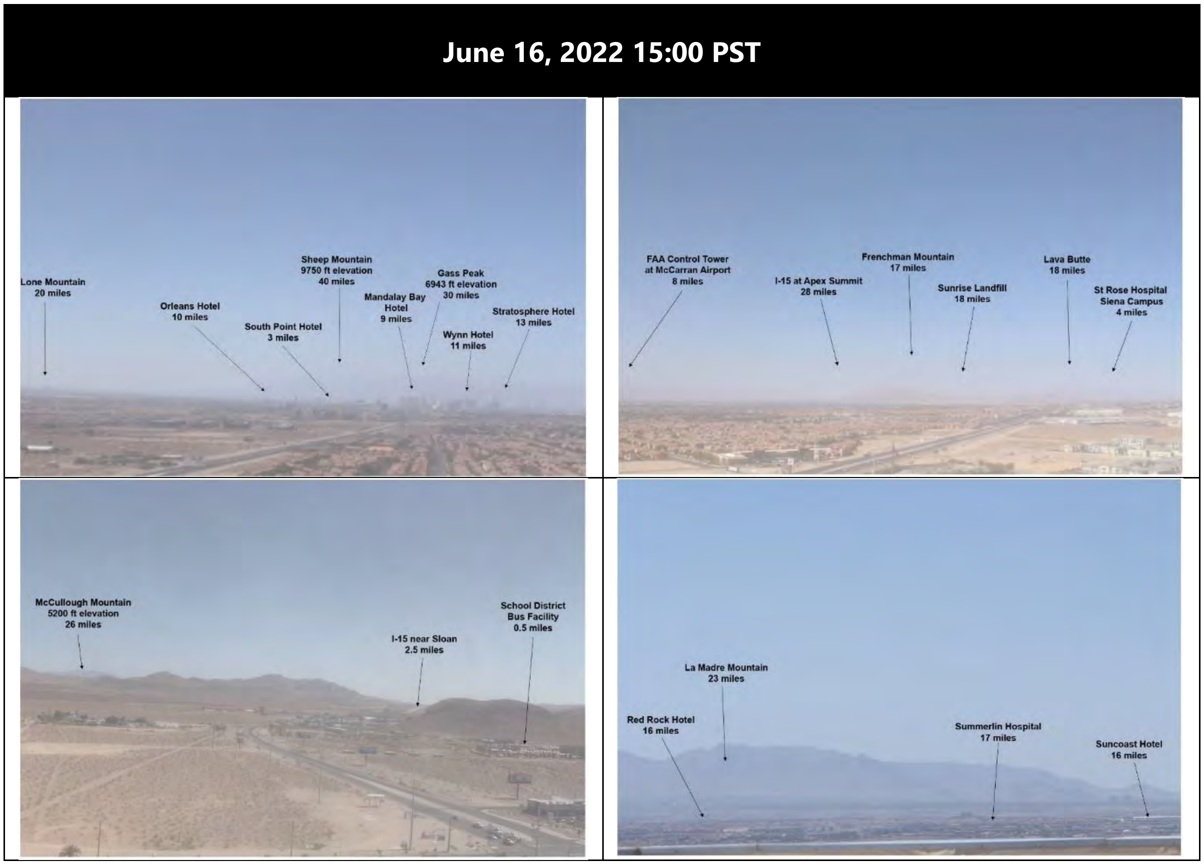

Figure 142. Camera images showing the north (top left), south (bottom left), northeast (top right), and northwest (bottom right) coordinal directions, taken from the M Resort Hotel in Clark County, NV, on June 16, 2022, at 15:00 LST.

Figure 143 through Figure 145 show the hourly $PM_{2.5}$, CO, and NO_2 concentrations for June 16, 2022. Figure 143**Figure 98** shows $PM_{2.5}$ concentrations compared to the diurnal 10th-90th percentile $PM_{2.5}$ concentration, calculated from 2017-2022, for each event-affected site and supporting sites in Clark County. On June 16, hourly $PM_{2.5}$ concentrations are not enhanced above the diurnal 90th percentile for most hours and monitoring sites. By June 17, the smoke plume was over Clark County, shown via HMS, meaning smoke was transported into the area between June 16 and 17. The bulk of smoke likely was transported into the area around midnight on June 17, as shown by the quick rate of change in $PM_{2.5}$ concentrations around midnight at all sites. This suggests the main smoke plume was pushing westward and finally reached the area late on June 16 and into early June 17. $PM_{2.5}$ concentrations were not extremely high during this period because this regional smoke plume was likely significantly dispersed by the time it reached Clark County. While the main plume of smoke reached Clark County after the MDA8 ozone period on June 16, back trajectories show transport from the Baja, Mexico, Arizona, and New Mexico fire plumes before they were directly overhead in Clark County.

Hourly CO and NO_2 concentrations are shown in **Figure 144** and Figure 145, alongside the 10th-90th percentile diurnal concentrations, calculated from 2017-2022, at each of the event-affected and supporting sites that measure CO and NO_2. There was not significant evidence for smoke impacts for either pollutant, but clearly another air mass influenced the area by the afternoon on June 16 when both typical diurnal cycles for CO and NO_2 are completely suppressed. Concentrations for both pollutants stayed nearly flat at most sites through June 17.

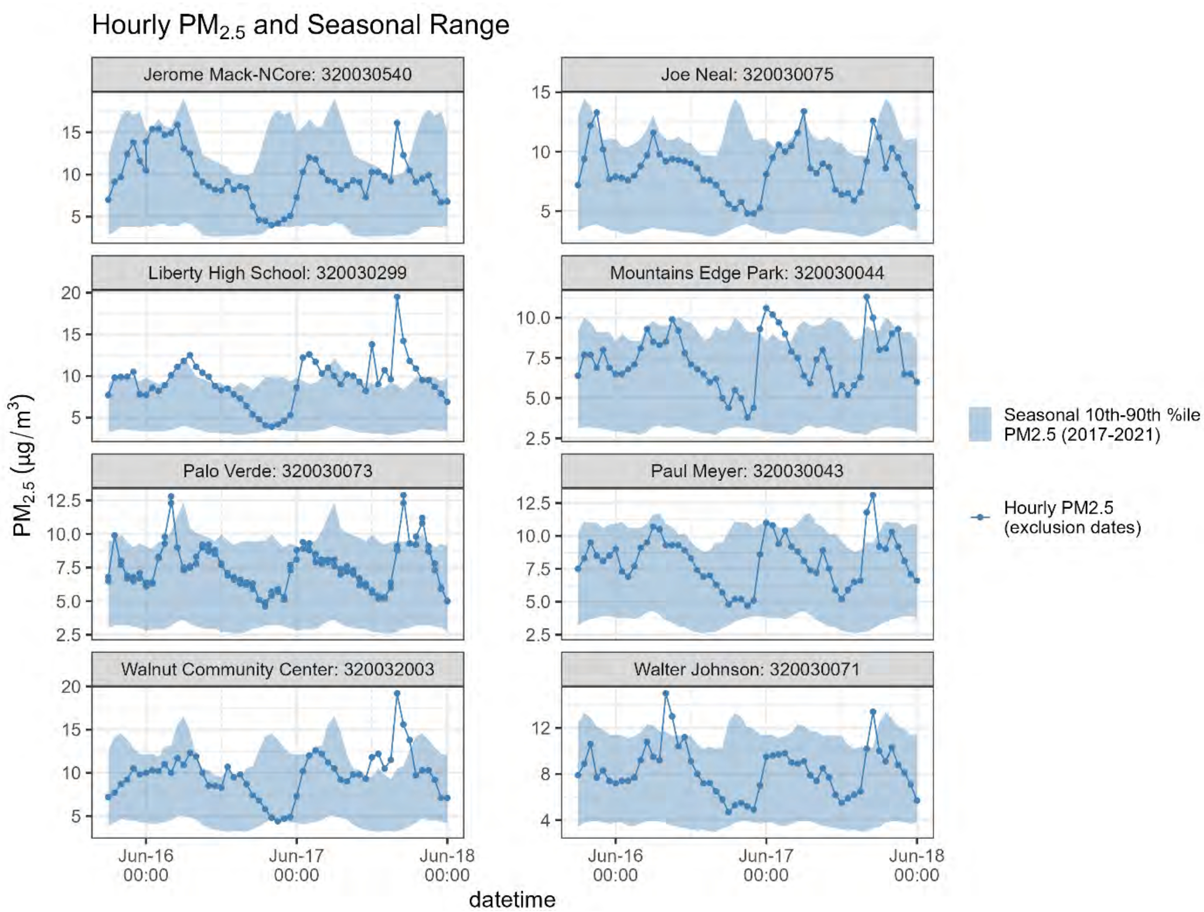

Figure 143. Hourly $PM_{2.5}$ measurements overlaid on the 10th-90th percentile diurnal concentration at the event-affected measurement sites and supporting sites that measure $PM_{2.5}$ concentrations. The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2022.

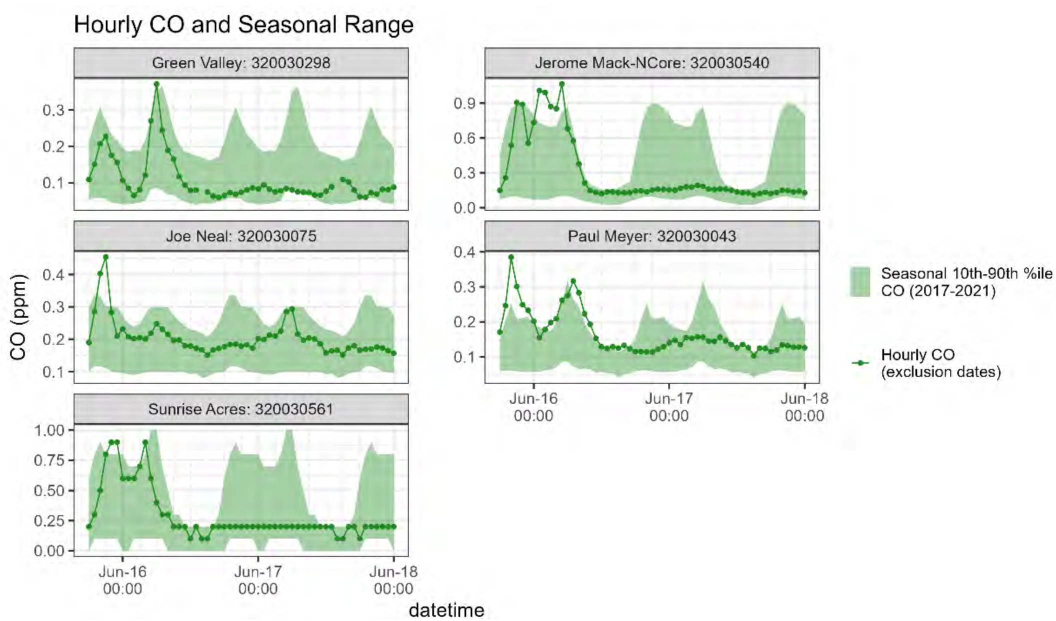

Figure 144. Hourly CO measurements overlaid on the 10th-90th percentile diurnal concentration at the event-affected sites and supporting sites that measure CO. The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2022.

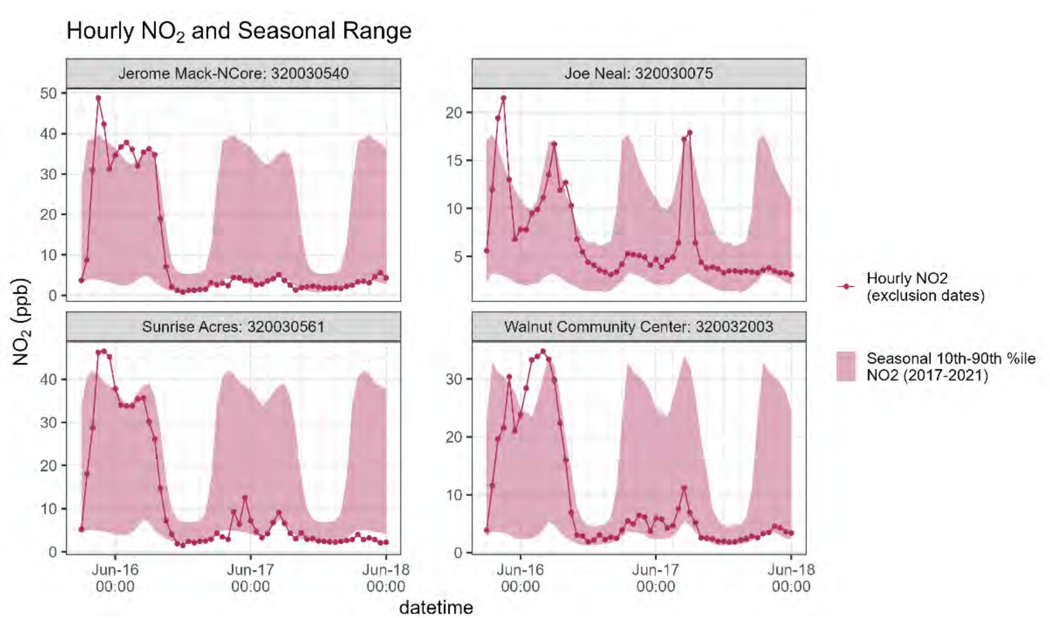

Figure 145. Hourly NO_2 measurements overlaid on the 10th-90th percentile diurnal concentration at the event-affected sites and supporting sites that measures NO_2. The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2022.

Three 8-hr acetaldehyde cannister measurements are taken every three days at the Jerome Mack-NCore site each year from June 1 through August 30. The resulting acetaldehyde data for before, after and on the exclusion date are in **Figure 146**. Enhanced acetaldehyde concentrations may be an indication of the presence of wildfire smoke, although this can also be due to other photochemical reactions and anthropogenic sources.[34,35,36] The measurement on June 16, 2022, from 04:00 – 12:00 PST was well above the 2022 90^{th} percentile and was the second highest measurement of acetaldehyde during 2022. The measurement on June 16 at 12:00-20:00 PST was also at the 90th percentile of data for 2022, indicating an unusual amount of acetaldehyde, coinciding with the transport of smoke into the area.

[34] Wentworth et al. (2018) Impacts of a large boreal wildfire on ground level atmospheric concentrations of PAHs, VOCs and ozone. Atmospheric Environment. https://www.sciencedirect.com/science/article/pii/S1352231018300190.
[35] Liang et al. (2022) Aging of Volatile Organic Compounds in October 2017 Northern California Wildfire Plumes. Environmental Science & Technology. https://pubs.acs.org/doi/full/10.1021/acs.est.1c05684.
[36] Vicente et al. (2011) Measurement of trace gases and organic compounds in the smoke plume from a wildfire in Penedono (central Portugal). Atmospheric Environment. https://www.sciencedirect.com/science/article/pii/S1352231011006145.

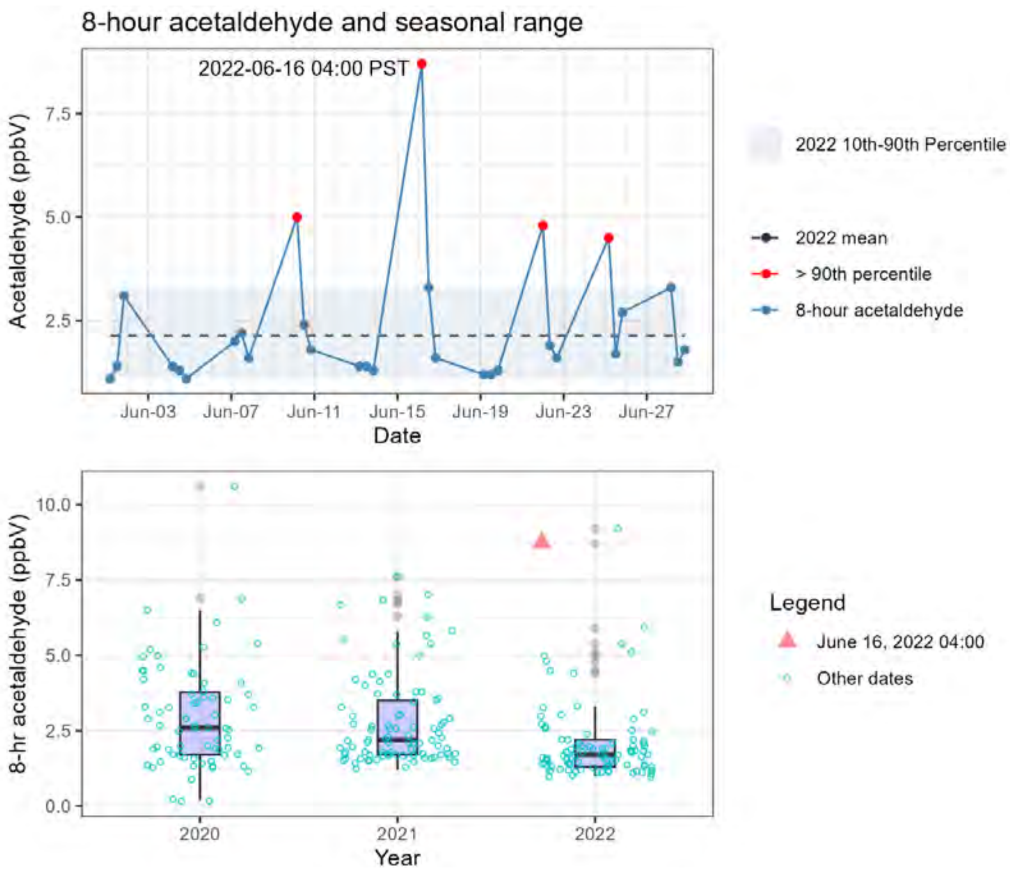

Figure 146. (Top) 8-hr acetaldehyde measurements before, on, and after the exclusion date overlaid on the 10th-90th percentile concentration in 2022. (Bottom) 8-hr acetaldehyde measurements grouped by year of measurement, where the box indicates the 25th-75th percentile of data, and the median is the solid line across the box. Individual datapoints have been overlaid across the boxplots.

5.1.5 Event Statistics

Table 31 summarizes the daily measurements of ozone, $PM_{2.5}$, CO, and NO_2 concentrations collected at the Joe Neal and Paul Meyer sites on the June 16, 2022, exclusion day, as well as the percentile rank of the observations compared to the previous five years of data (2018-2022) at both sites. On June 16, 2022, ozone MDA8 measurements at both sites were above the 94.9th percentile. The 24-hr average $PM_{2.5}$ concentrations were above the 76th percentile at both sites on June 16. The 1-hr daily maximum CO concentrations reached the 37th percentile at the Joe Neal site on June 16 and the 82nd percentile at the Paul Meyer site, and 1-hr daily maximum NO_2 measurements at the Joe Neal site reached the 65th percentile on June 16.

Table 31. Percentile of pollutant measurements on the June 16, 2022, exclusion day compared with most recent five years of pollutant concentration data (2018-2022).* The percentile rank is calculated across the ozone production season (May 1-October 31) of 2018-2022.

Date	Site Name	Site Code	Ozone		$PM_{2.5}$		CO		NO_2	
			Ozone MDA8 (ppb)	Percent Rank	$PM_{2.5}$ 24-hr Avg ($\mu g/m^3$)	Percent Rank	CO 1-hr Daily Max (ppb)	Percent Rank	NO_2 1-hr Daily Max (ppb)	Percent Rank
6/16/2022	Joe Neal	320030075	72	96.8	7.7	76.8	248	37*	16.7	65.7
6/16/2022	Paul Meyer	320030043	71	94.9	7.6	78.3	317	82.4*		

*Sites that have less than five years of data available for a given parameter.

5.2 July 17, 2022

5.2.1 Event Summary

An ozone event took place on July 17, 2022, and affected five sites in Clark County, Nevada. Regional wildfire smoke is suspected to have contributed to the NAAQS exceedances. The data presented in this document shows there was a large amount of smoke from wildfires in the western U.S. and Canada during the ozone event. Additionally, there is evidence of a large, well-mixed boundary layer above Clark County on July 17 that could mix smoke to the surface and affect ozone concentrations. This combination of evidence, which includes HMS smoke detection, PBL analysis, HYSPLIT back trajectories, and HRRR smoke data, suggests this may be an unrepresentative event for base and future design value ozone assessments.

Sites exceeding the NAAQS had MDA8 ozone concentrations ranging from 72-76 ppb (**Table 32**). Throughout the Las Vegas Valley, MDA8 ozone concentrations ranged from 64 to 76 ppb on July 17, with an average MDA8 concentration of 70 ppb. **Figure 147** shows time series graphs of hourly ozone concentrations that exceeded the seasonal means (calculated using May 1 – October 31, 2017-2021) and 10th-90th percentiles at each affected site. Ozone levels exceeded 90th percentiles on July 17 during peak midday ozone hours and remained above the 90th percentile at most sites during the expected overnight minimum.

Table 32. Sites with MDA8 ozone levels (ppb) exceeding the NAAQS on July 17, 2022.

Site Name	Site Code	Ozone MDA8 (ppb)
Garrett Jr. High	320030602	72
Green Valley	320030298	73
Jerome Mack-NCore	320030540	71
Liberty High School	320030299	72
Walnut Community Center	320032003	76

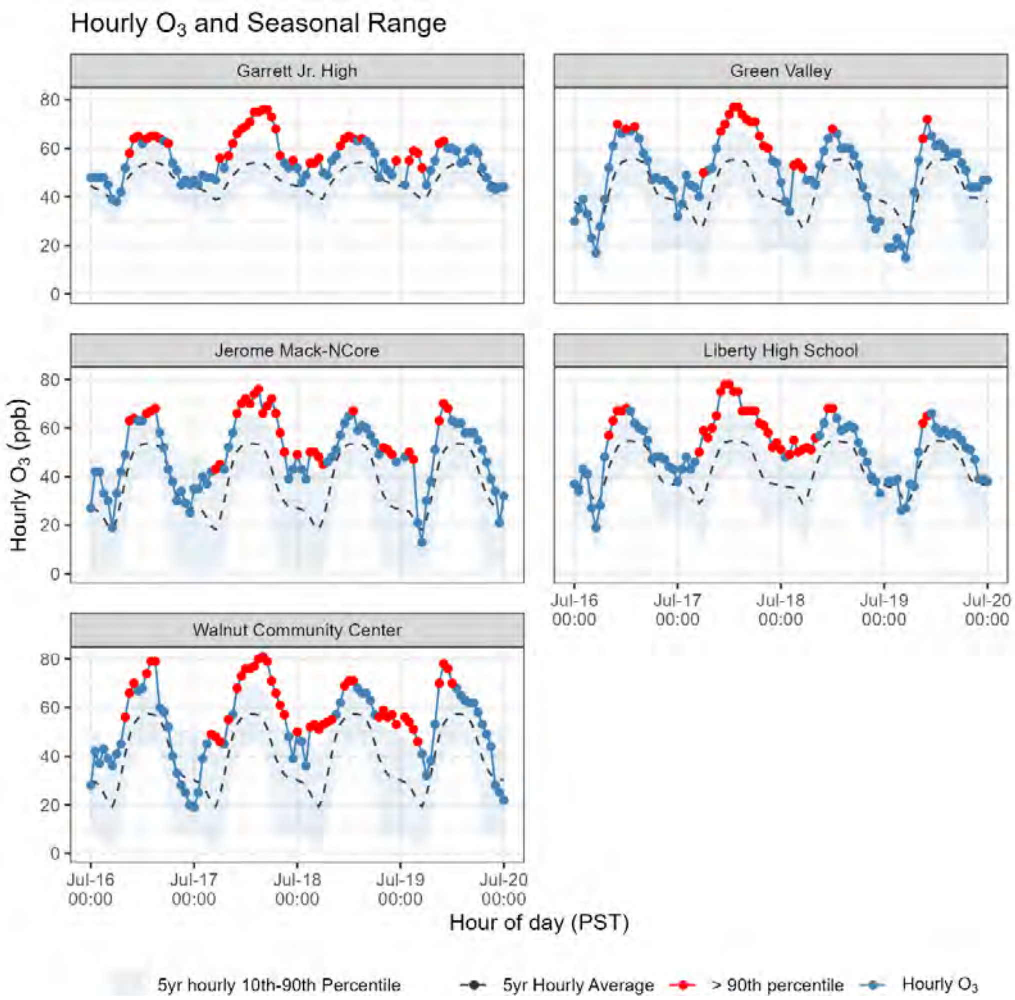

Figure 147. Hourly ozone concentrations (ppb) compared to 5-yr ozone season (May 1-October 31) hourly means and 10th-90th percentiles. Data collection did not begin until 2021 at Garrett Jr. High, Liberty High School, and Walnut Community Center, so data for these sites begins from the first available date in 2021.

5.2.2 Identification of Wildfires

Figure 148 shows the progression of smoke dispersion across the United States between July 14 and July 17, 2022. HMS smoke maps are created using visible satellite imagery from Geostationary Operational Environmental Satellites (GOES). Visible imagery is only available during the sunlit part of the GOES orbit. Therefore, smoke movement during nighttime hours is inferred between the daylight-generated smoke maps. Distinct northeasterly plumes from fires in northern Nevada and California are visible on July 14. In addition, significant smoke from extremely large Canadian wildfires is also visible. Over the next few days, this smoke was driven in a clockwise direction by a high-pressure system (as shown in Figure 149) over the southwestern United States, looping south across the center of the U.S., then through New Mexico and west towards southern Nevada. By July 17, 2022, HMS smoke was detected over Clark County, NV.

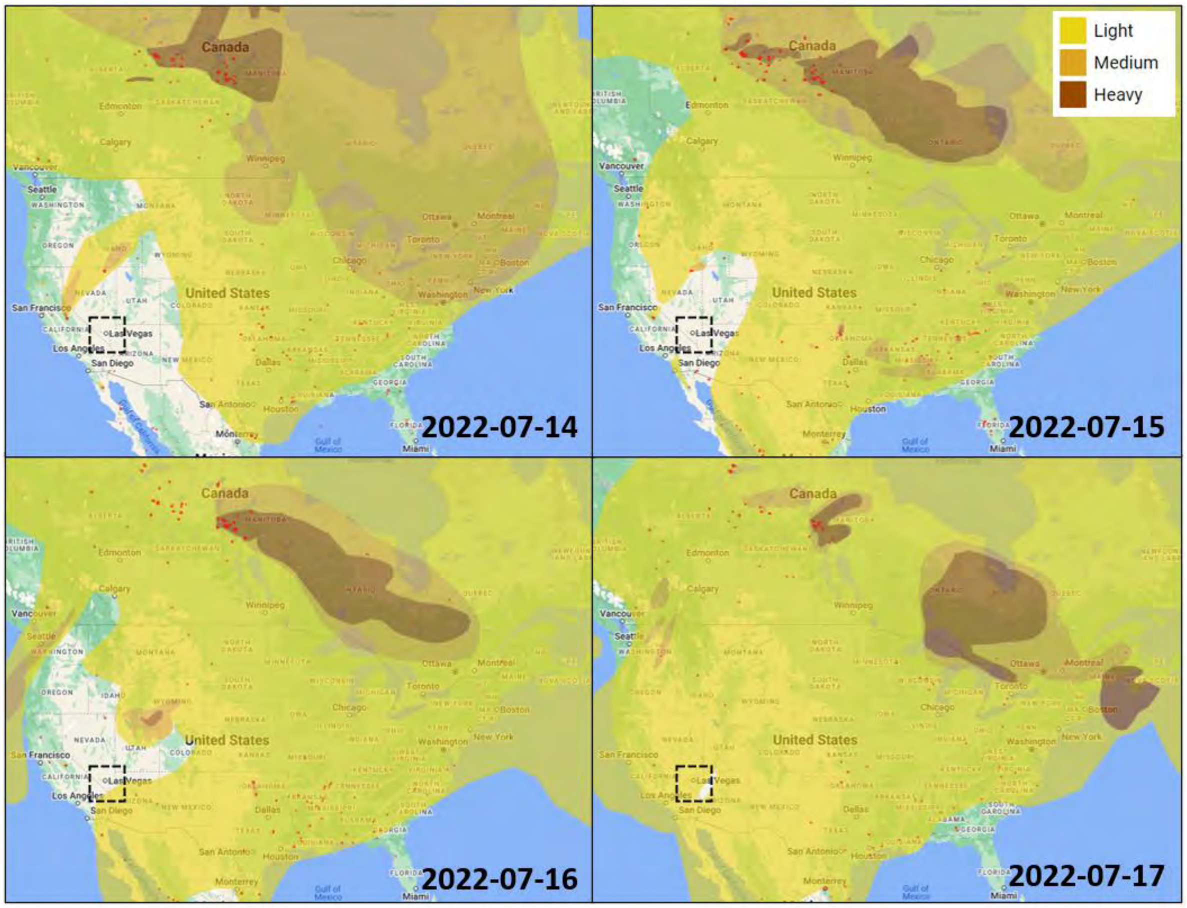

Figure 148. HMS smoke for July 14 - 17, 2022 is included with qualitative smoke density. Clark County, NV, is enclosed by black, dashed box.

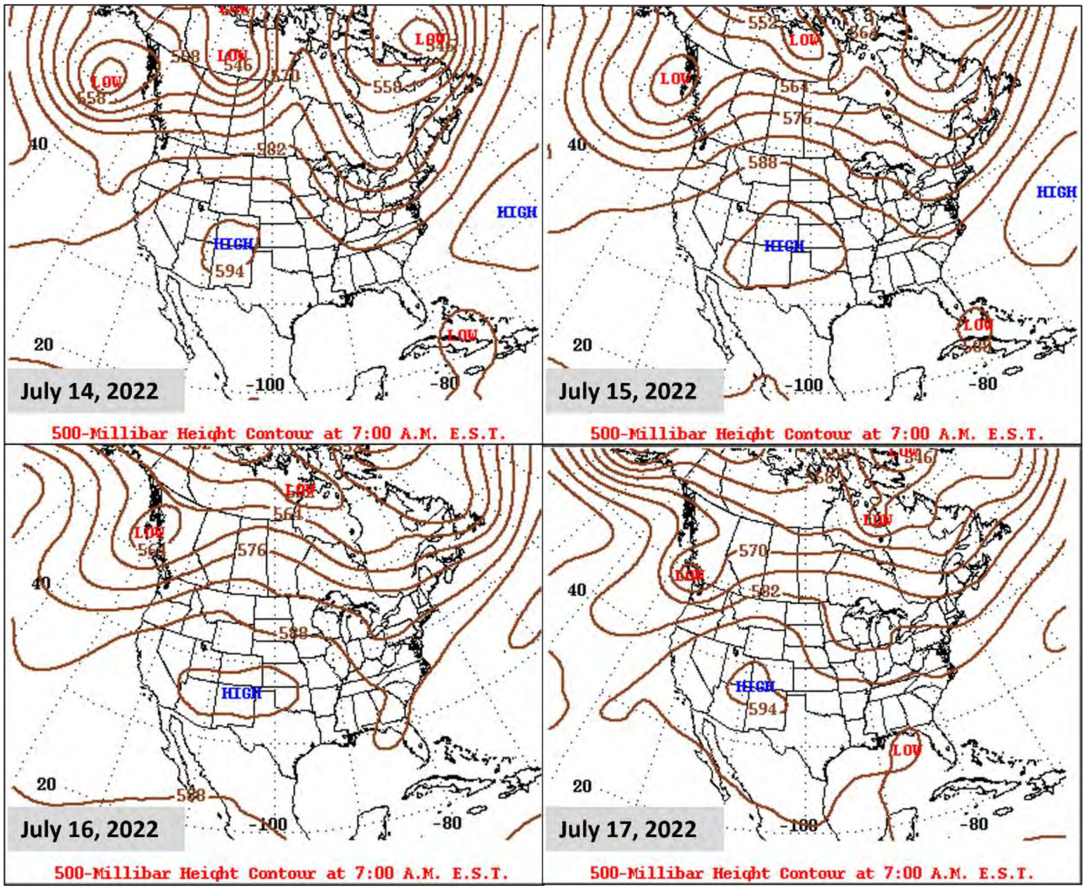

Figure 149. Daily 500-mb weather maps for July 14-17, 2022.

Two active wildfires in the United States, the Wildcat fire in Nevada and the Washburn fire in California, as well as three very large Canadian wildfires were active during the days leading up to and including the exclusion dates. All five fires had sizable growth leading up to July 17, as seen in Table 33, which presents the state, total acres within the fire perimeter, actively burning acres on the exclusion day, and the start date and containment date for each fire based on data from InciWeb.[37] Daily information on the Canadian wildfires is limited beyond satellite information. Fire perimeters for each fire identified in relation to Clark County are shown in Figure 150. A zoomed in view of each fire is shown in Figure 151.

[37] https://inciweb.nwcg.gov/

Table 33. Wildfires affecting Clark County on the exclusion days. Accurate daily fire sizes on or before the exclusion day for the Canadian fires are not available. Instead, these fires were chosen based on HMS fire points.

Wildfire Name	State	Total Acres	Acres Burned on or Before Exclusion Days	Start Date	Containment Date
Wildcat	Nevada	21,429	21,440 (Jul 16)[38]	Jul 13	Jul 23
Washburn	California	4,886	4,856 (Jul 17)[39]	Jul 7	Sep 30
Manitoba Complex	Manitoba-Canada	103,924[40]	--	Jul 13	Sep 5
Saskatchewan Fire	Saskatchewan - Canada	43,068[3]	--	Jun 29	Jul 27
Alberta Complex	Alberta-Canada	75,974[3]	--	Jun 15	Oct 9

[38] https://inciweb.nwcg.gov/incident-publication/nvhtf-wildcat/wildcat-fire-7162022-news-release. Note this number is larger than the total acres burned because it was an estimate. Total area burned can then be lower when the final burn perimeter is identified.

[39] https://inciweb.nwcg.gov/incident-publication/caynp-washburn-fire/washburn-fire-daily-update-for-july-22-2022

[40] https://cwfis.cfs.nrcan.gc.ca/datamart/download/nbac

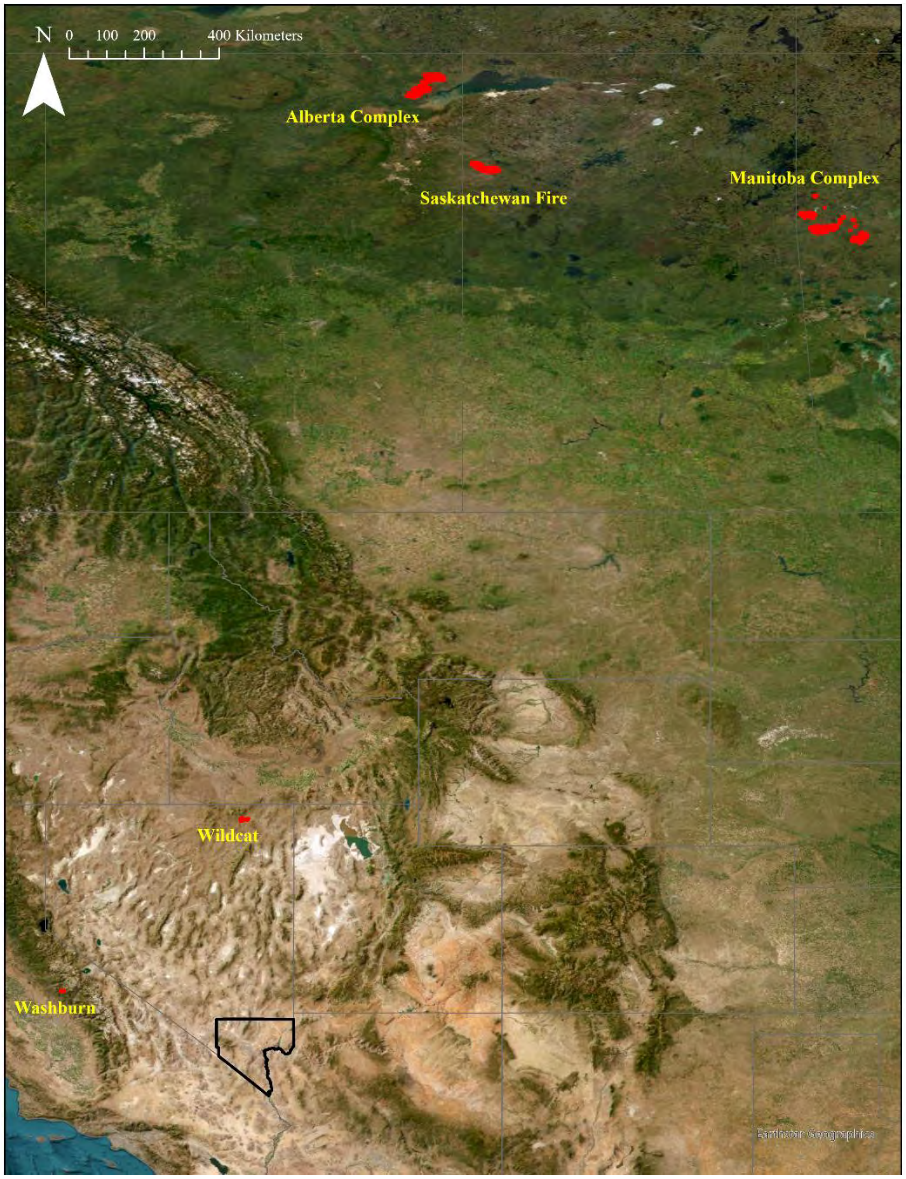

Figure 150. Final fire perimeters (red) for the five active fire regions during the July 17, 2022, exclusion date in relation to Clark County (black perimeter).

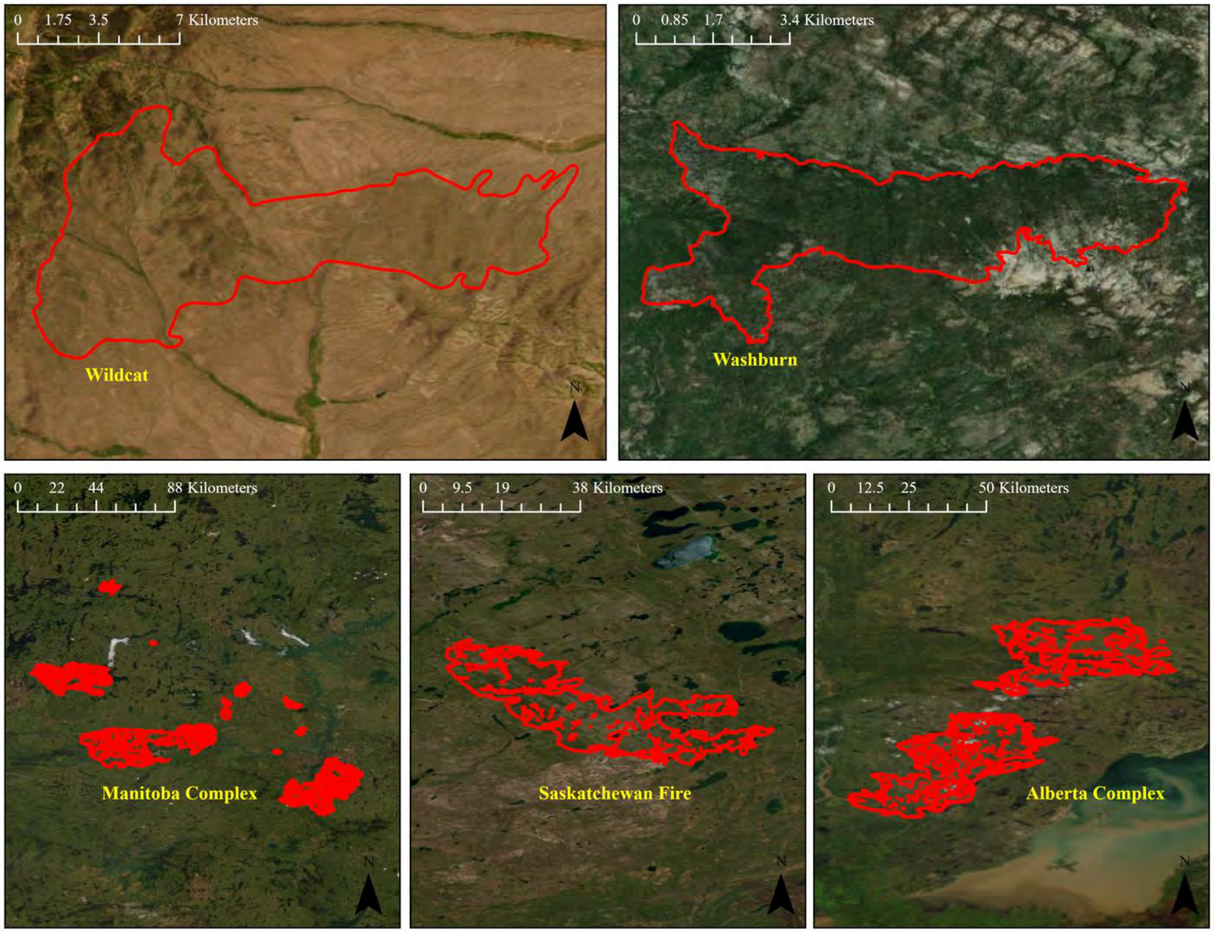

Figure 151. Final fire perimeters (red) for the five active fire regions during the July 17, 2022, exclusion date.

5.2.3 Regional Analysis

To examine the effect of wildfire smoke in Clark County (as indicated by HMS smoke in Section 5.2.2), we first determined the meteorological conditions on and before the July 17 event. We specifically focused on the boundary layer dynamics to determine the depth of mixing and possibility of smoke mixing to the surface. We then used this information to model smoke via HYSPLIT and compared the results with independent data sources (including HMS and HRRR data).

The planetary boundary layer (PBL) denotes the atmospheric layer closest to the surface, and the height of the PBL describes the vertical extent of surface air characteristics. Atmospheric soundings and PBL maps provide visualizations of the extent of vertical mixing in the lower troposphere. The three skew-T diagrams, shown in Figure 152, show the vertical profile of the atmosphere on July 17 at 00:00 UTC (July 16 at 16:00 PST), July 17 at 12:00 UTC (04:00 PST), and July 18 at 00:00 UTC (July 17 at 16:00 PST). The three skew-T diagrams are characterized primarily by large, well-mixed boundary layers above the surface with the temperature line following near the dry adiabatic lapse rate lines.

While the sounding on July 17 at 04:00 PST shows a small inversion near 900 mb (~745 m), this inversion is gone by the afternoon on July 17. By July 17 at 16:00 PST (July 18 at 00:00 UTC), the lower PBL was well-mixed up to approximately 4,000 m above ground level (agl). The NAM-modeled PBL heights over Clark County on July 17 at 16:00 PST also correspond to the PBL heights of approximately 3,000 to 4,000 m shown on the sounding of the same time (**Figure 153**; this map shows PBL heights above 2 km in altitude in 1 km increments, with colors starting at 1 km). Both the skew-T diagrams and NAM-modeled PBL heights over Clark County on July 17 indicate a deep well-mixed boundary layer. The PBL analysis shows a well-mixed boundary layer up to 4,000 m on July 17, which suggests smoke transported into the well-mixed layer would be available for mixing with the surface and would potentially impact ground-level ozone concentration.

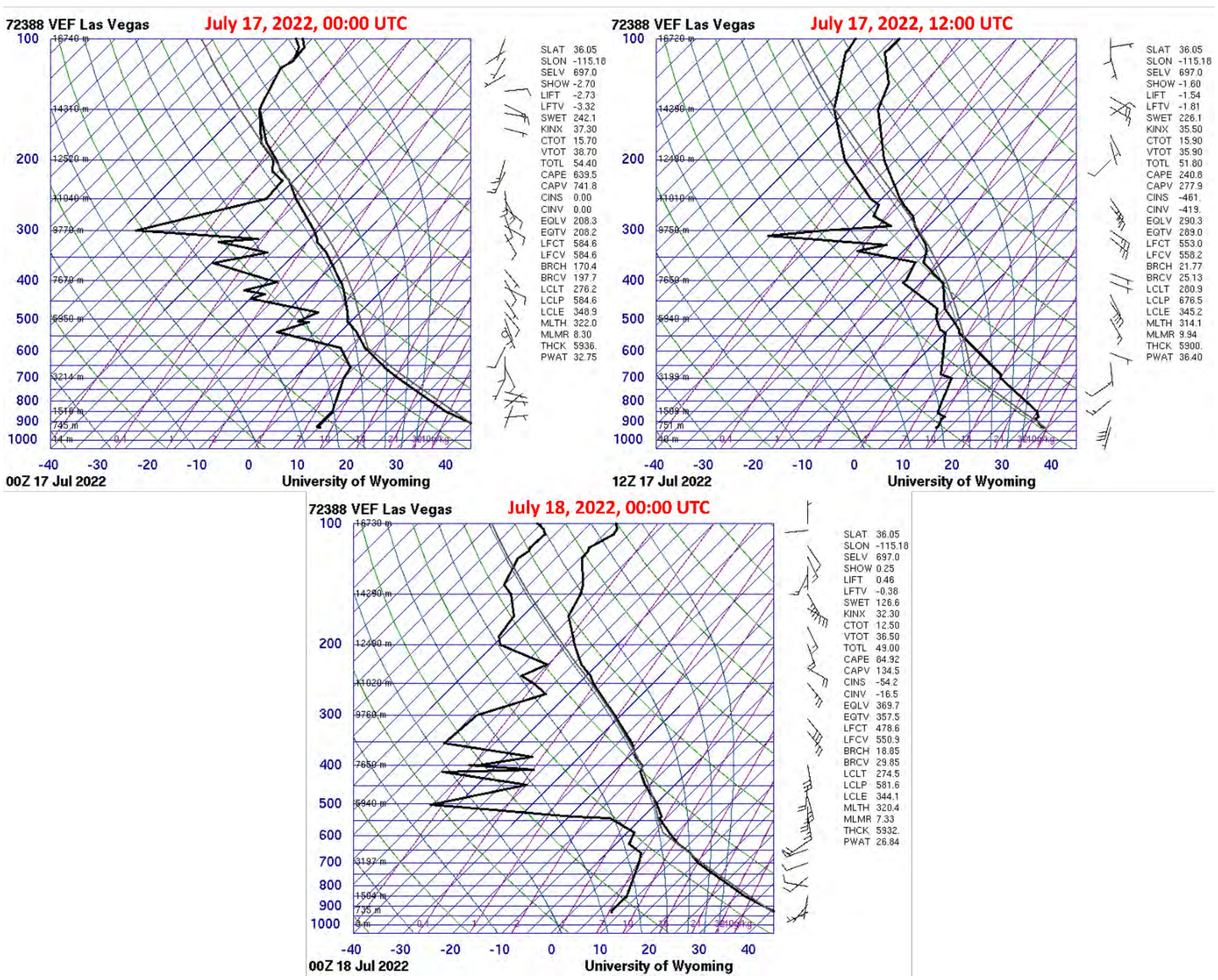

Figure 152. Skew-T soundings launched from the Las Vegas National Weather Service Office from July 17 at 00:00 UTC (July 16 at 16:00 PST) (top left) to July 18 at 00:00 UTC (July 17 at 16:00 PST) (bottom right).

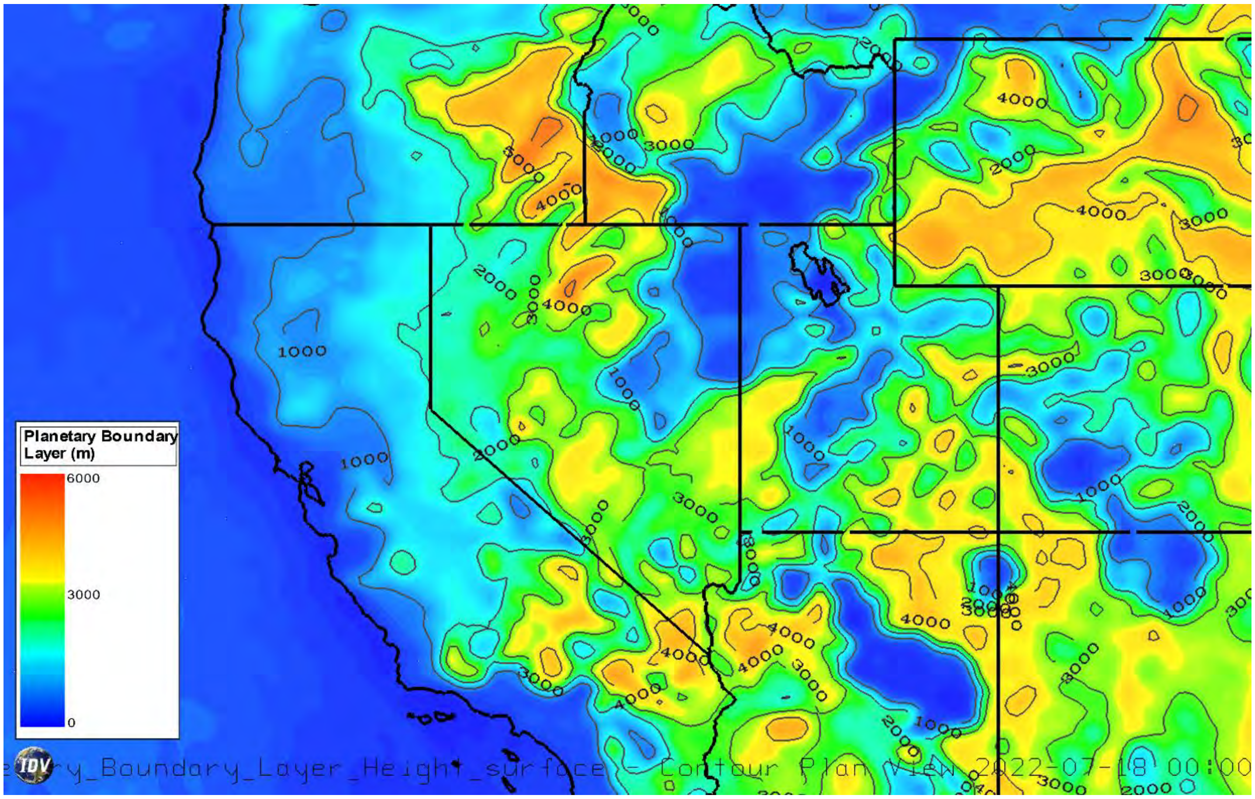

Figure 153. PBL height contour map based on the NAM model for July 18 at 00:00 UTC (July 17 at 16:00 PST). The gray lines denote PBL heights above 1 km in altitude in 1 km increments. Color contouring starts at 0 km.

HYSPLIT dispersion modeling could not be accurately performed for this exclusion date due to the large contributions from Canadian wildfires. Daily fire sizes of the Canadian fires could not be obtained and, therefore, these fires could not be modeled accurately. A HYSPLIT back trajectory was performed for 16:00 UTC (08:00 PST) on July 17, 2022 (**Figure 154**). The back trajectory shows the general pattern of air from the California and Nevada fires, through the Canadian smoke plumes, and finally, descent of air into the boundary layer in the Las Vegas area from high altitude in the morning on July 17, providing smoke products and ozone precursors, setting up a day for enhanced ozone production. This is consistent with the HMS and meteorological narrative from Section 5.2.2 and shows air descending from 4,000 – 8,000 m into a well-mixed boundary layer.

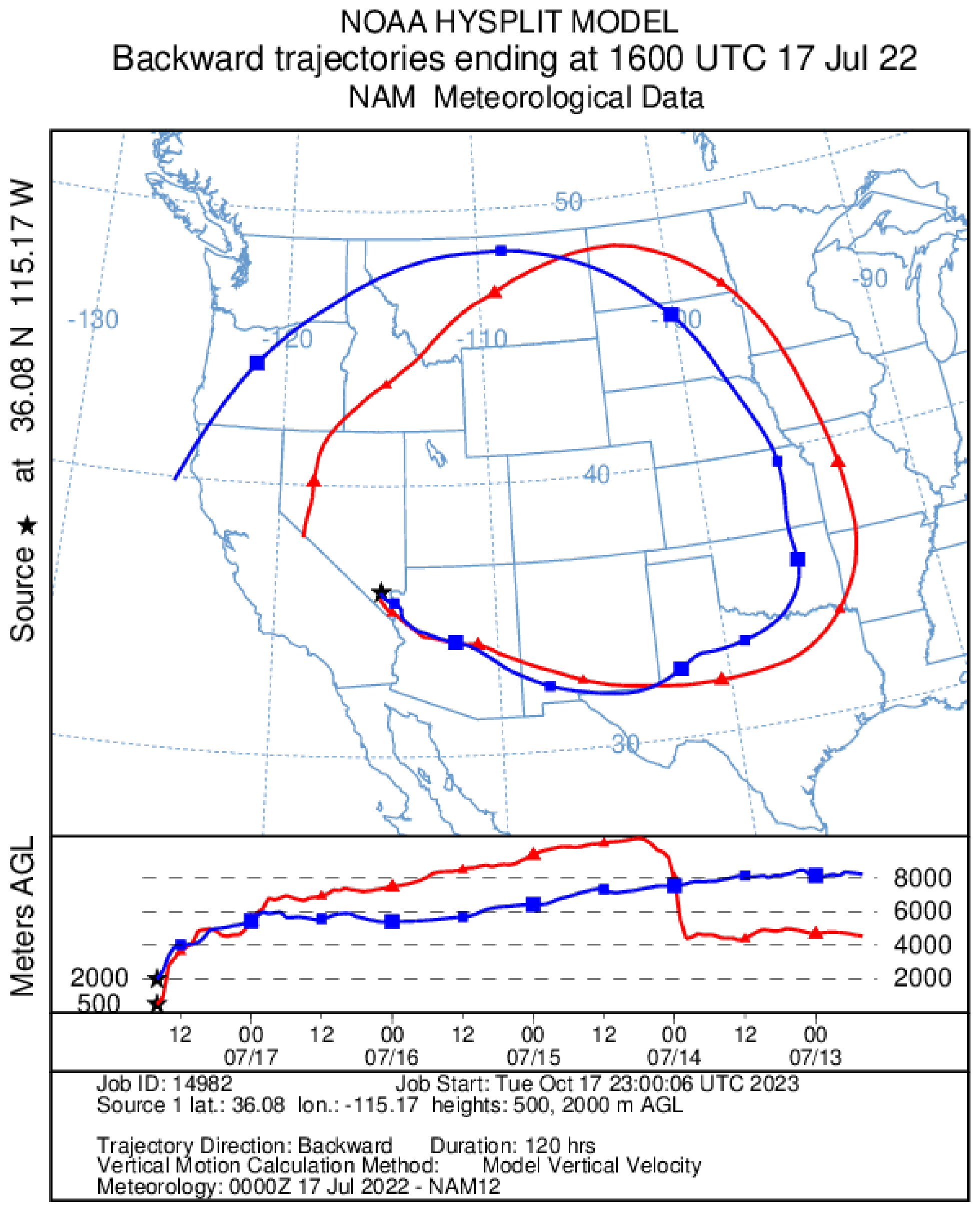

Figure 154. HYSPLIT back trajectory initiated at 16:00 UTC (08:00 PST) on July 17, 2022, using NAM 12 km meteorology. The back trajectory ran for 120 hours, ending in Las Vegas (36.08, -115.17) at 500 m and 2,000 m agl.

The HRRR smoke product shown in Figure 155 indicates low levels of vertically integrated smoke over the Clark County region on July 17, 2022. Based on the boundary layer analysis, smoke entering the area would have been well mixed with the surface. Combining the HMS, meteorological information, PBL analysis, HYSPLIT back trajectories, and HRRR data, we see that smoke merged between the California, Nevada, and Canadian fires into a large, regional pool of smoke, which was transported around a high-pressure system in the southwest U.S. and descended into the well-mixed boundary layer in Las Vegas on July 17, 2022.

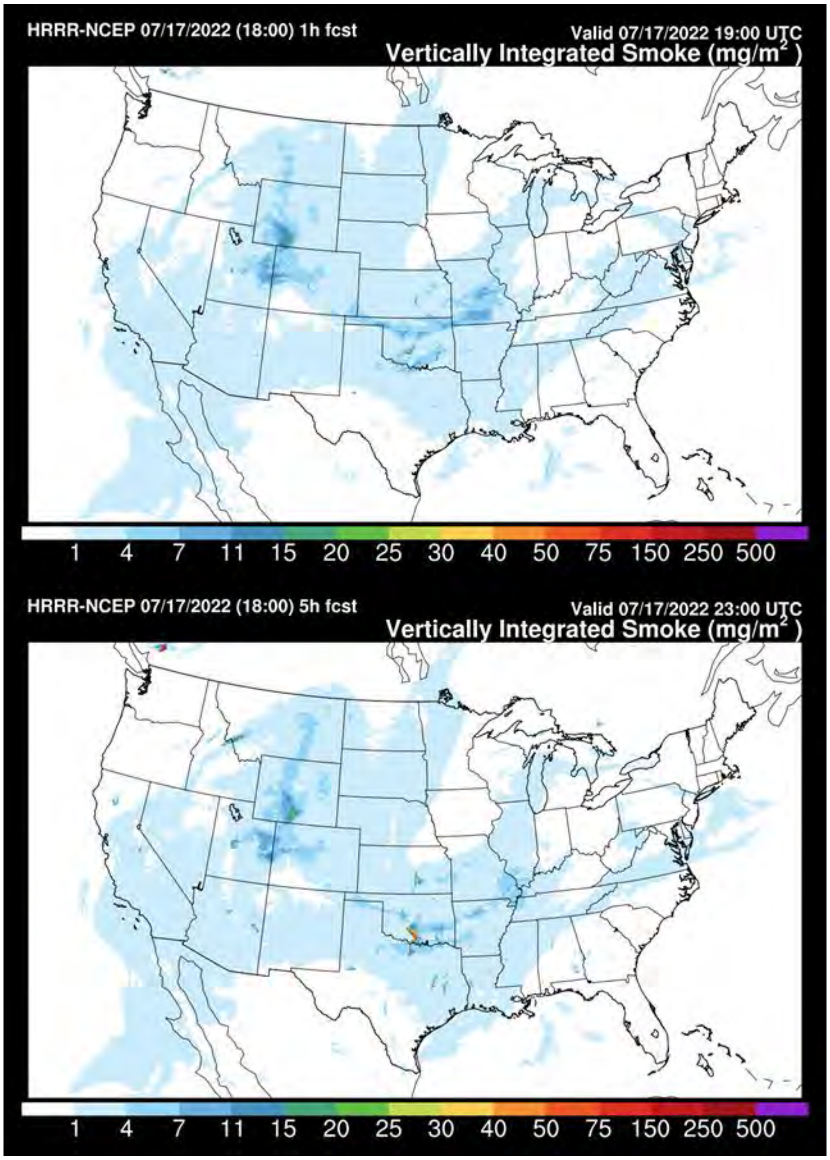

Figure 155. HRRR vertically integrated smoke forecast for July 17, 2022, at 11:00 PST and 15:00 PST.

5.2.4 Surface Impacts

Visible imagery is unavailable for this event due to a thunderstorm and associated dust event on the morning of July 17, 2022. METAR reports from July 17 showing the reports of the thunderstorm during early morning are shown in Figure 156.

Time	Temperature	Dew Point	Humidity	Wind	Wind Speed	Wind Gust	Pressure	Precip.	Condition
12:53 AM	93 °F	53 °F	26 %	CALM	0 mph	0 mph	27.53 in	0.0 in	Fair
1:53 AM	92 °F	52 °F	26 %	SE	5 mph	0 mph	27.53 in	0.0 in	Fair
2:53 AM	91 °F	52 °F	26 %	E	5 mph	0 mph	27.54 in	0.0 in	Fair
3:53 AM	93 °F	55 °F	28 %	CALM	0 mph	0 mph	27.55 in	0.0 in	Fair
4:53 AM	92 °F	55 °F	29 %	E	5 mph	0 mph	27.56 in	0.0 in	Fair
5:53 AM	92 °F	58 °F	32 %	ESE	8 mph	0 mph	27.58 in	0.0 in	Fair
6:53 AM	92 °F	61 °F	35 %	VAR	3 mph	0 mph	27.61 in	0.0 in	Light Rain
7:19 AM	92 °F	62 °F	37 %	E	3 mph	0 mph	27.62 in	0.0 in	Thunder in the Vicinity
7:34 AM	90 °F	66 °F	45 %	NNE	7 mph	0 mph	27.62 in	0.0 in	Light Rain
7:53 AM	89 °F	68 °F	50 %	CALM	0 mph	0 mph	27.63 in	0.0 in	Thunder in the Vicinity
8:00 AM	90 °F	66 °F	45 %	CALM	0 mph	0 mph	27.63 in	0.0 in	Thunder
8:15 AM	91 °F	64 °F	41 %	W	14 mph	0 mph	27.61 in	0.0 in	Thunder in the Vicinity
8:28 AM	91 °F	61 °F	36 %	W	15 mph	0 mph	27.59 in	0.0 in	Light Rain
8:53 AM	92 °F	59 °F	33 %	NE	10 mph	0 mph	27.62 in	0.0 in	Partly Cloudy
9:53 AM	94 °F	56 °F	28 %	E	6 mph	0 mph	27.63 in	0.0 in	Fair
10:53 AM	98 °F	54 °F	23 %	VAR	3 mph	0 mph	27.61 in	0.0 in	Fair

Figure 156. METAR report at Las Vegas International Airport (KLAS) during the morning of July 17, 2022, showing the thunderstorm that occurred early in the morning.

In this section, we provide the typical pollutant concentrations at each affected site, but the morning thunderstorm obscured any useful $PM_{2.5}$ information. $PM_{2.5}$ concentrations compared to the diurnal 10th-90th percentile $PM_{2.5}$ concentrations, calculated from 2017-2022, are shown for event-affected and supporting measurement sites in Figure 157. Hourly $PM_{2.5}$ concentrations exceeded the diurnal 90th percentile $PM_{2.5}$ concentration at multiple sites in the Las Vegas Valley between 03:00 and 06:00 PST on July 17 due to outflow from an approaching thunderstorm. The $PM_{2.5}/PM_{10}$ ratios for this event (Figure 158) show a decrease during the thunderstorm and outflow boundary event early in the morning on July 17, consistent with a dust storm. After the dust storm concluded mid-morning on July 17, the ratio increased sharply and stays above average for most sites during the early afternoon. Higher $PM_{2.5}/PM_{10}$ values are more consistent with wildfire smoke. While the $PM_{2.5}/PM_{10}$ ratio does not increase significantly, neither do the absolute $PM_{2.5}$ concentrations (Figure 157). Due to the regional nature and very long-range transport, $PM_{2.5}$ is more likely to be dispersed and not significantly enhanced. The high altitude back trajectory shown in Section 5.2.3, however, indicates that smoke and ozone precursors could have been stored along a cold transport path to decompose and enhance ozone once mixed into the boundary layer in Las Vegas.

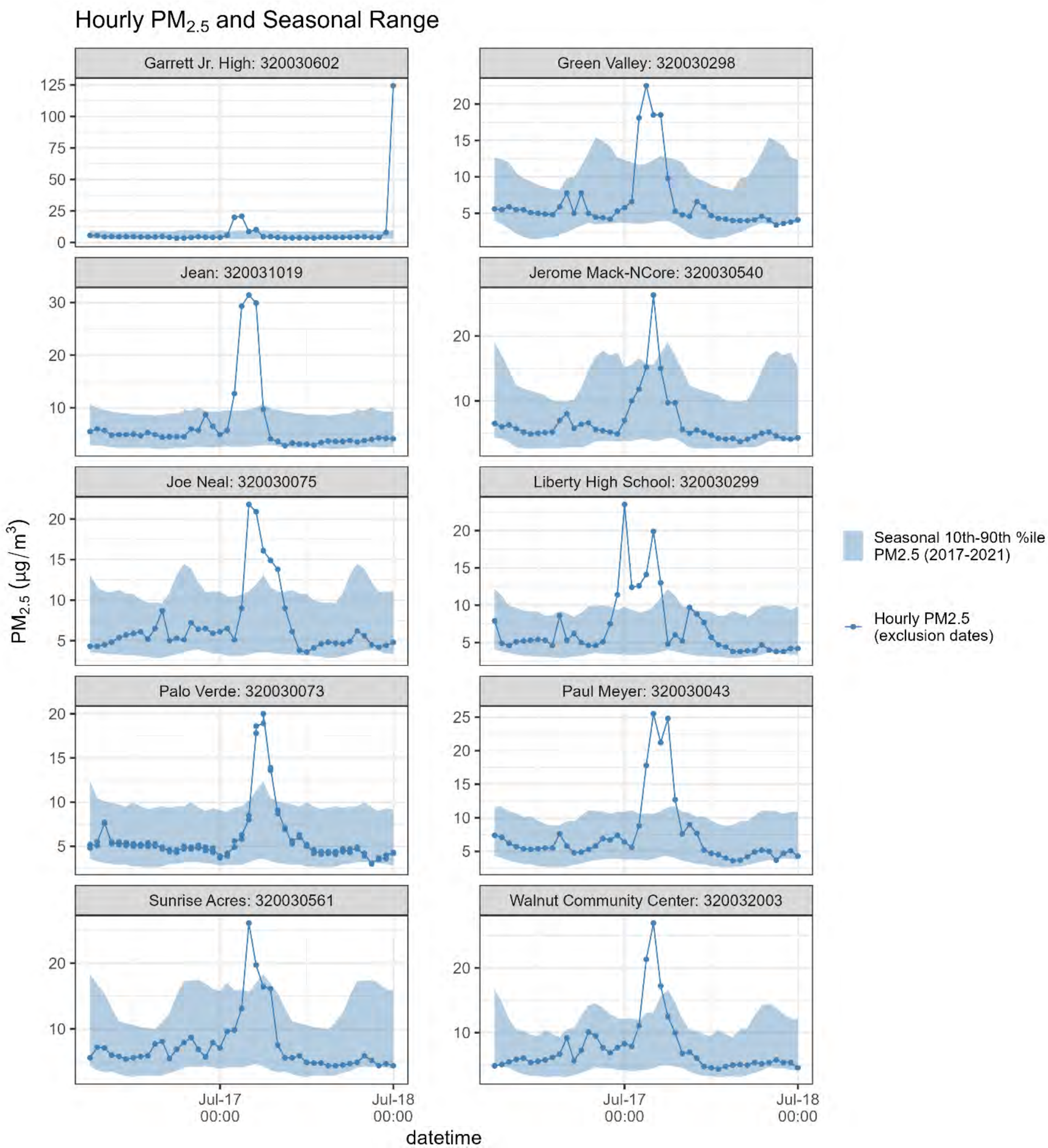

Figure 157. Hourly $PM_{2.5}$ measurements overlaid on the 10th-90th percentile diurnal concentration at event-affected measurement sites that measure $PM_{2.5}$ and supporting sites. The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2022.

Figure 158. Ratio of $PM_{2.5}/PM_{10}$ concentrations at the Green Valley, Jean, Jerome Mack-NCore, Paul Meyer, and Sunrise Acres monitoring sites during the July 17, 2022, event period. The 5-yr average $PM_{2.5}/PM_{10}$ diurnal ratio is displayed as a dotted line, and the 5th-95th percentile range is shown as a shaded ribbon. The 5th-95th percentile concentration is calculated across the ozone production season (June-August) of 2018-2022.

5.2.5 Event Statistics

Table 34 summarizes daily measurements of ozone, CO, and NO_2 concentrations on the exclusion day, as well as the percentile rank of the observation compared to the previous five years of ozone season data (May 1-October 31 of 2018-2022). $PM_{2.5}$ statistics are not included because the thunderstorm event anomalously enhanced the percentiles but is not associated with wildfire impacts. On July 17, 2022, ozone MDA8 measurements at all sites were above the 98th percentile. CO and NO_2 were not significantly enhanced, with CO 1-hr daily maximum concentrations and NO_2 1-hr daily maximum measurements below the 38th percentile at all sites. Lower concentrations of co-pollutants are consistent with very long-range transport of smoke.

Table 34. Percentile of pollutant measurements on the exclusion day compared with most recent five years* (2018-2022). The percentile rank is calculated across the ozone production season (May 1-October 31) of 2018-2022.

Date	Site Name	Site Code	Ozone		CO		NO_2	
			Ozone MDA8 (ppb)	Percent Rank	CO 1-hr Daily Max (ppb)	Percent Rank	NO_2 1-hr Daily Max (ppb)	Percent Rank
7/17/2022	Garrett Jr. High	320030602	72	99.7*				
7/17/2022	Green Valley	320030298	73	98.3	34	1.6*		
7/17/2022	Jerome Mack-NCore	320030540	71	98.1	167	11.7*	17.4	25
7/17/2022	Liberty High School	320030299	72	98.1*				
7/17/2022	Walnut Community Center	320032003	76	98.8*	300	38.3*	21.1	35.9*

*Sites that have less than five years of data available for a given parameter.

5.3 July 28-29, 2022

5.3.1 Event Summary

An ozone event took place across July 28-29, 2022, in Clark County, NV, and affected six monitoring sites on July 28 and one site on July 29, 2022. Regional wildfire smoke is suspected to have contributed to the NAAQS exceedances on these days. Major evidence includes smoke detection maps from the NOAA's HMS, dispersion model results from HYSPLIT, meteorological data, and HRRR smoke modeling results for July 28 and 29. This combination of evidence suggests that this may be an unrepresentative event for base and future design value ozone assessments.

Sites exceeding the NAAQS on July 28 had MDA8 ozone concentration ranging from 72-81 ppb (see Table 35). All sites within the Las Vegas Valley experienced MDA8 values on July 28 between 62 and 81 ppb, with an average MDA8 of 71 ppb. The high-altitude background site at the Spring Mountain (SM) Youth Camp also experienced an MDA8 value of 78 ppb on July 28, suggesting background enhancement to ozone concentrations, but as this site is outside of the Las Vegas Valley it is not significant for the design value assessments. On July 29, ozone concentrations had decreased in the Las Vegas Valley, with only the Palo Verde site experiencing an exceedance; on this day, the average MDA8 ozone concentration for the sites within the Las Vegas Valley was 65 ppb.

Table 35. Sites with MDA8 ozone levels above the NAAQS on July 28 or 29, 2022, in Clark County, NV.

Date	Site	Site Code	MDA8 Ozone (ppb)
7/28/2022	Palo Verde	320030073	81
7/28/2022	Walter Johnson	320030071	78
7/28/2022	Paul Meyer	320030043	77
7/28/2022	Mountains Edge Park	320030044	74
7/28/2022	Joe Neal	320030075	73
7/28/2022	Liberty High School	320030299	72
7/29/2022	Palo Verde	320030073	71

Time series graphs showing hourly ozone concentrations that exceeded the seasonal means and 10th-90th percentiles (calculated using data from May 1-October 31, 2017-2021) at each affected site are shown in Figure 159.

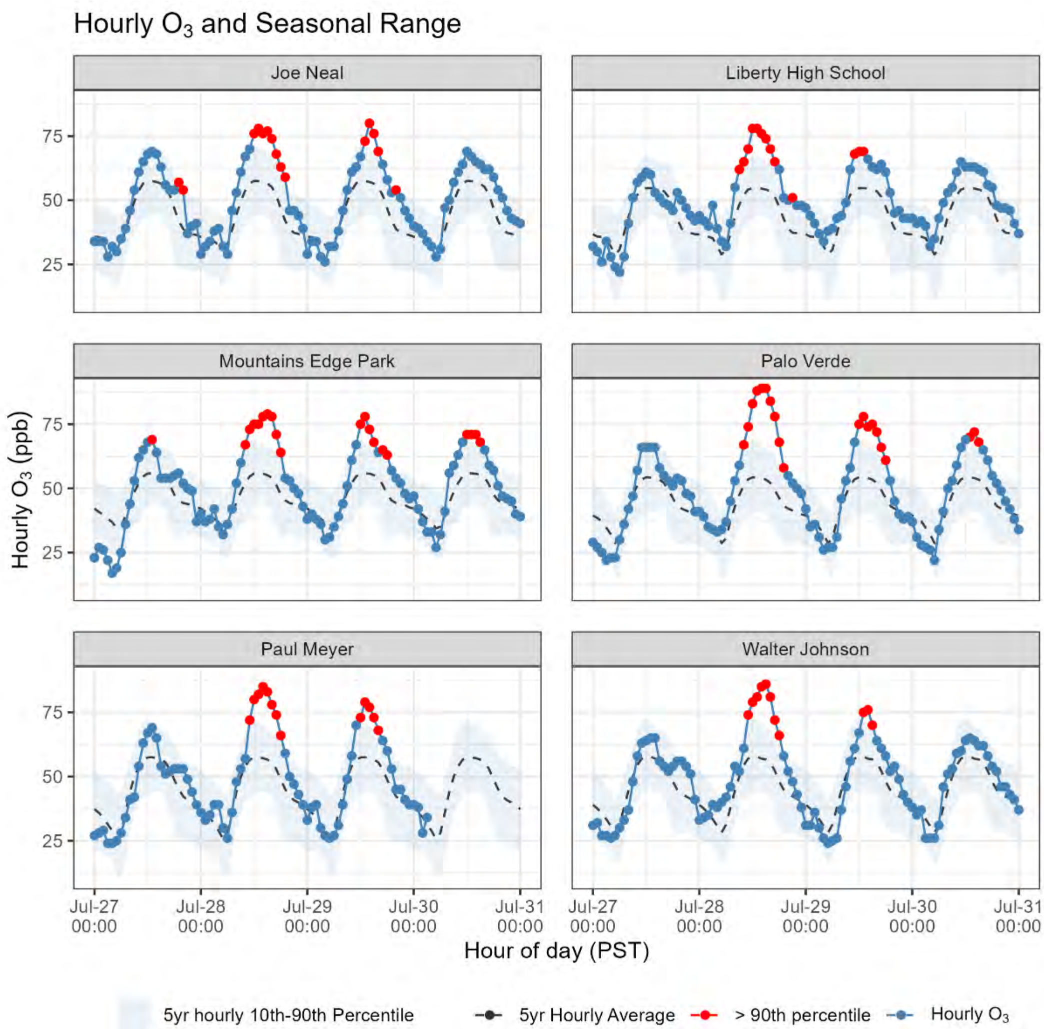

Figure 159. Hourly ozone concentrations (ppb) across June 27-31, 2022, compared to 5-yr* ozone season (May 1-October 31) hourly means and 10th-90th percentiles. Note: data collection at the Data collection at the Liberty High School and Mountains Edge Park sites did not begin until 2021.

5.3.2 Identification of Wildfires

Figure 160 shows HMS maps that display the progression of smoke across the United States between July 26 and 29, 2022. HMS smoke maps are created using visible satellite imagery from Geostationary Operational Environmental Satellites (GOES). Visible imagery is only available during the sunlit part of the GOES orbit; therefore, smoke movement during nighttime hours is inferred between the daylight-generated smoke maps. On July 26, smoke from fires in California and Idaho spread mostly northward and eastward in dense plumes. Over the next three days, plumes from both regions dispersed over wider areas to blanket most of the western U.S., including Clark County, on July 28 and 29, 2022.

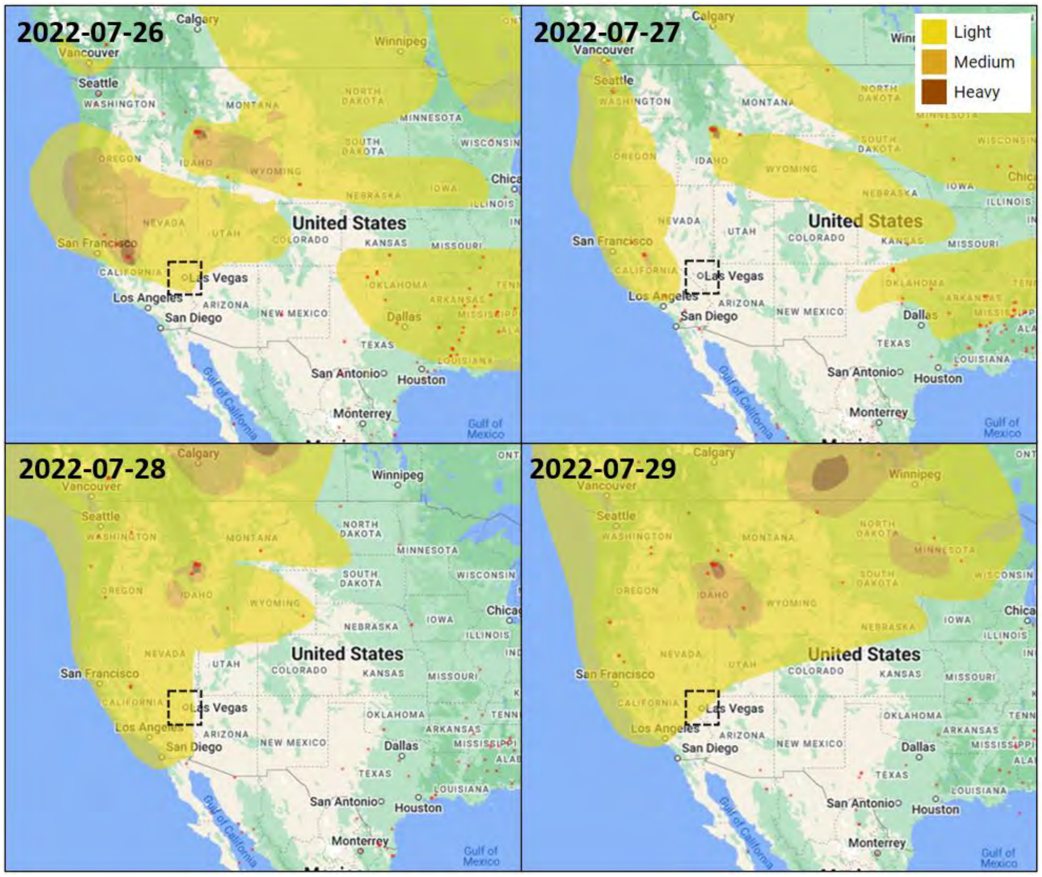

Figure 160. HMS smoke maps for July 26-29, 2022, showing smoke transport and qualitative smoke density. Clark County, NV, is enclosed by a dashed, black box on each map.

Two fires (the Moose Fire in Idaho and the Oak Fire in California) were active during the days leading up to and including the exclusion dates. Both fires had sizable growth leading up to July 28-29 (Table 36). The active fire area on July 28 is provided based on a post from the Salmon-Challis National Forest U.S. Forest Service account for the Moose Fire, and InciWeb data for the Oak Fire. Fire perimeters in relation to Clark County are in Figure 161, and a closer view of each is in Figure 162.

Table 36. Wildfires affecting Clark County on July 28-29.

Wildfire Name	State	Total Acres	Acres Burned on or Before July 28-29	Start Date	Containment Date
Moose	Idaho	130,144	40,388 (July 28)[41]	Jul 17	Nov. 9
Oak	California	19,244	19,191 (July 28)[42]	Jul 22	Aug. 11

[41] https://www.facebook.com/plugins/post.php?href=https%3A%2F%2Fwww.facebook.com%2Fsalmonchallisnf%2Fposts%2Fpfbid02fsCqh6BDaSbXqmH4NZzbhaqnXwLWf7VrMhuafof6kSTRTvJ1qsXwSwGCS5hTwGHzl

[42] https://inciweb.nwcg.gov/incident-publication/casnf-oak-fire/oak-fire-update-72822-pm

Figure 161. Final fire perimeters (red) for the two active fire regions during the July 28-29, 2022, exclusion dates in relation to Clark County (black perimeter).

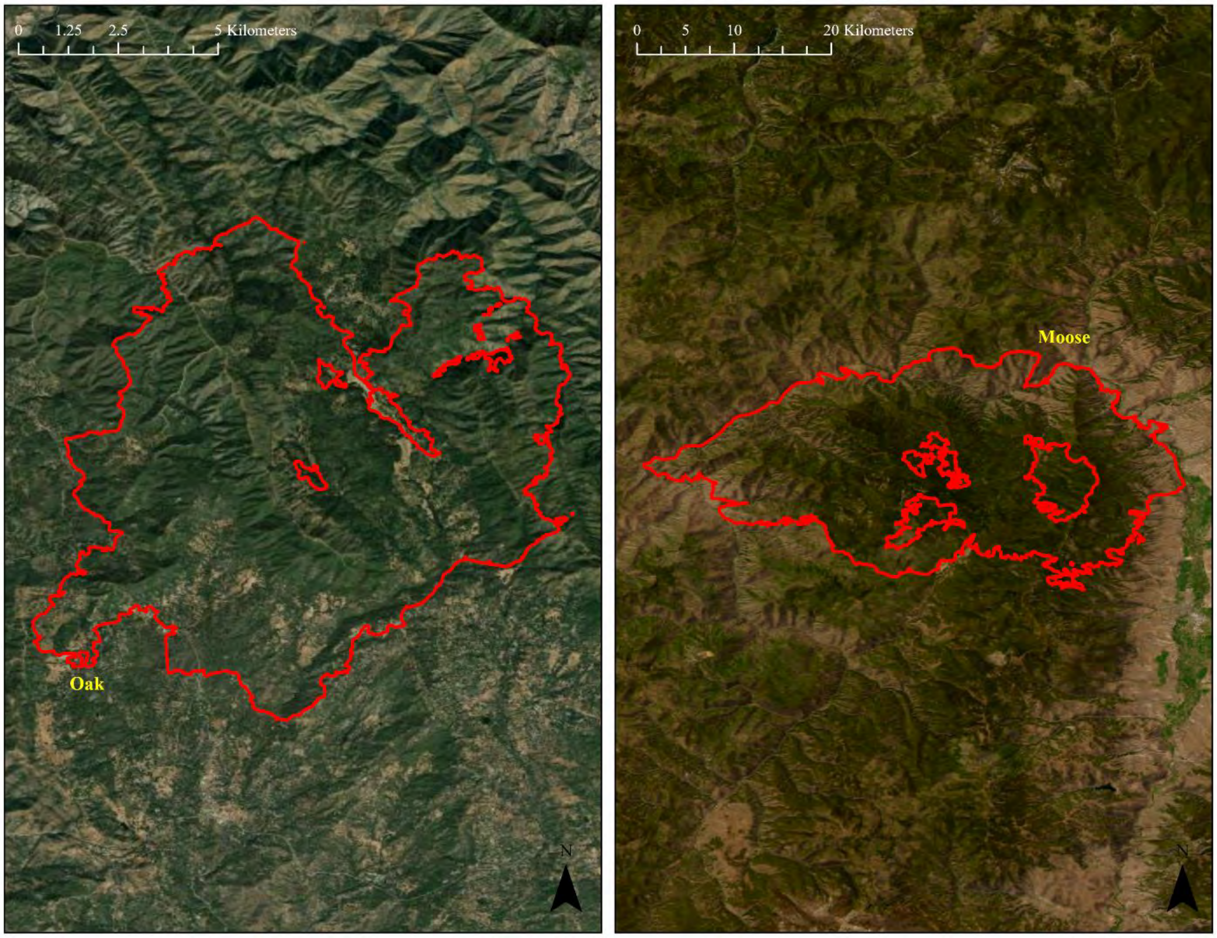

Figure 162. Final fire perimeters (red) for the two active fire regions during the July 28-29, 2022, exclusion dates.

5.3.3 Dispersion Modeling and Regional Analysis

To examine the effect of wildfire smoke in Clark County (as indicated by the HMS smoke maps shown in Section 5.3.2), we first determined the meteorological conditions on and before the July 28-29 event. We specifically focused on the boundary layer dynamics to determine the depth of mixing and possibility of smoke mixing to the surface. We then used this information to model smoke via HYSPLIT and compare the results with independent data sources (including HMS and HRRR data).

The planetary boundary layer (PBL) denotes the atmospheric layer closest to the surface, and the height of the PBL describes the vertical extent of surface air characteristics. Atmospheric soundings and PBL maps provide visualizations of the extent of vertical mixing in the lower troposphere. The five skew-T diagrams in Figure 163 show the vertical profile of the atmosphere every 12 hours from July 28 at 00:00 UTC (July 27 at 16:00 PST) to July 30 at 00:00 UTC (July 29 at 16:00 PST). The five skew-T diagrams are characterized primarily by their diurnal changes in the lower troposphere from consecutive soundings; the soundings taken at 12:00 UTC (i.e., 04:00 PST) show a near-surface temperature inversion that inhibited vertical mixing between the near-surface and mid-troposphere, whereas the soundings taken at 00:00 UTC (i.e., 16:00 PST) show an approximately dry-adiabatic temperature lapse rate, indicating that the lower troposphere was well mixed with a PBL of approximately 2,500 m above ground level (agl) (~700 mb). This indicates that, while morning conditions typically include capping inversions, by the afternoon a deep well-mixed boundary layer had formed in Clark County on the exclusion dates. To confirm the PBL heights estimated from the skew-T diagrams, we use the Sounding and Hodograph Analysis and Research Program in Python (SHARPpy). We use the raw theta temperature data to determine the PBL heights relative to the temperature profile. **Figure 164** shows the profile for July 28 at 16:00 PST and **Figure 165** shows the profile for July 29 at 16:00 PST. Using this method, we find a PBL height of 2,581 m in the afternoon on July 28 and 2,556 m in the afternoon on July 29. This confirms the initial estimate of the skew-T diagrams in Figure 163.

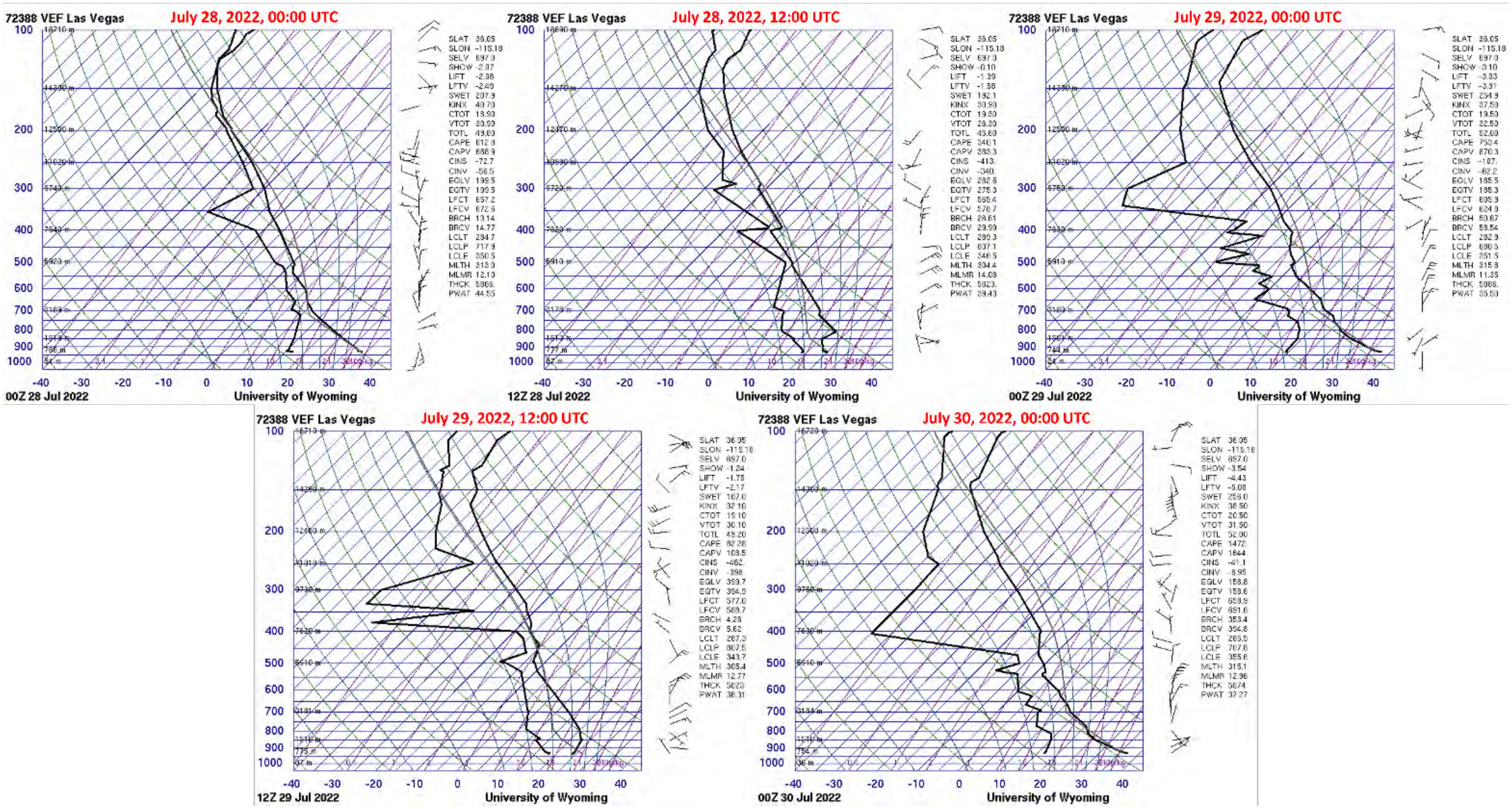

Figure 163. Skew-T soundings launched from the Las Vegas National Weather Service Office from July 28, 2022, at 00:00 UTC (July 27 at 16:00 PST) (top left), to July 30 at 00:00 UTC (July 29 at 16:00 PST) (bottom right).

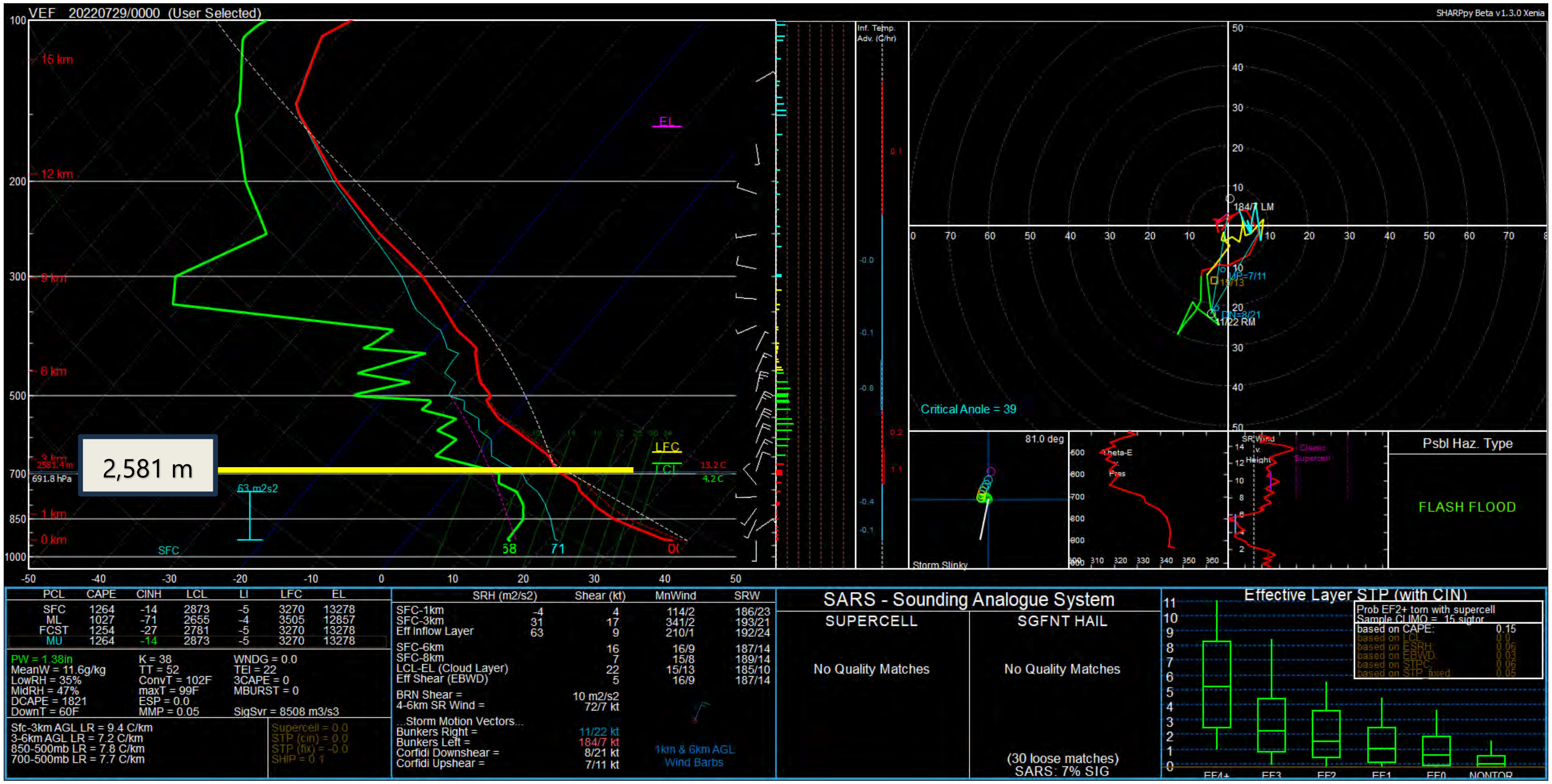

Figure 164. SHARPpy sounding output for July 29, 2022, at 00:00 UTC (July 28 at 16:00 PST). The yellow line indicates the level of the PBL height derived from the raw theta temperature and labeled for clarity.

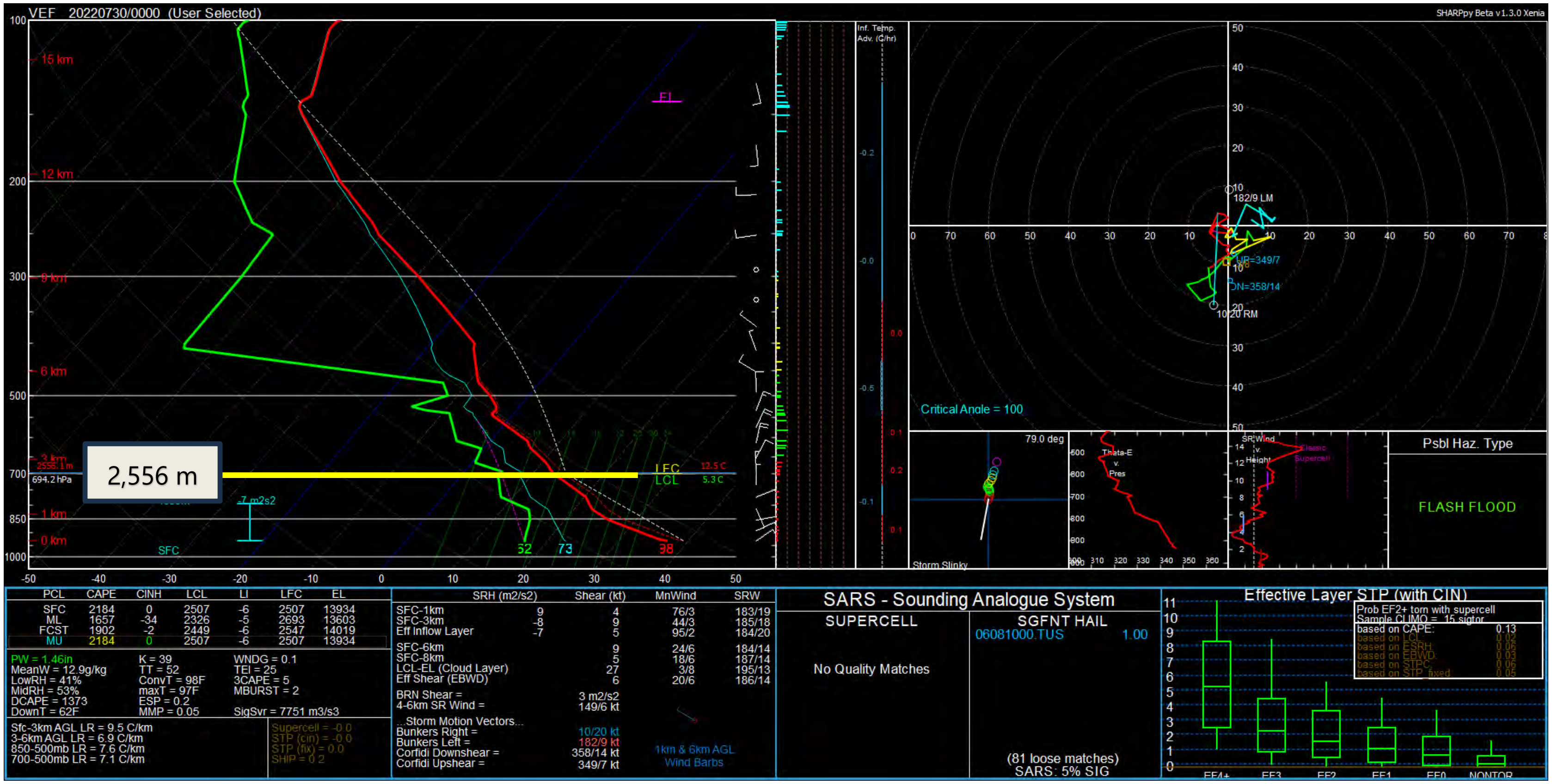

Figure 165. SHARPpy sounding output for July 30, 2022, at 00:00 UTC (July 29 at 16:00 PST). The yellow line indicates the level of the PBL height derived from the raw theta temperature and labeled for clarity.

To identify air mass source regions on the exclusion dates, HYSPLIT back trajectories were generated at four start points before and during the July 28-29, 2022, event within the PBL heights identified previously. Trajectories start and run backward for 72 hours on July 28, 2022, at 12:00 UTC (July 28 at 04:00 PST), July 29 at 00:00 UTC (July 28 at 16:00 PST), July 29 at 12:00 UTC (July 29 at 04:00 PST), and July 30 at 00:00 UTC (July 29 at 16:00 PST) to capture the overnight and daytime transport that would affect ozone precursors and concentrations (see **Figure 166**). These back trajectories are consistent with the skew-Ts presented previously. All back trajectories show the general pattern of air circulating around from the north/northwest and entering the Las Vegas area from the northeast. The trajectories travel through the merged smoke plume from the Moose and Oak Fires and enter Clark County at 2,000 agl. During the day, this air was well mixed within the boundary layer. Overnight the boundary layers were not as high, but smoke likely remained above the boundary layer. As PBL heights increased each day, aloft smoke and ozone precursors could mix to the surface. This smoke may have contributed ozone precursors to the area during the daytime higher PBL heights, enhancing ozone production. This transport path, with air mass source regions extending into areas covered by smoke, is consistent with the HMS and meteorological narrative from Section 5.3.2.

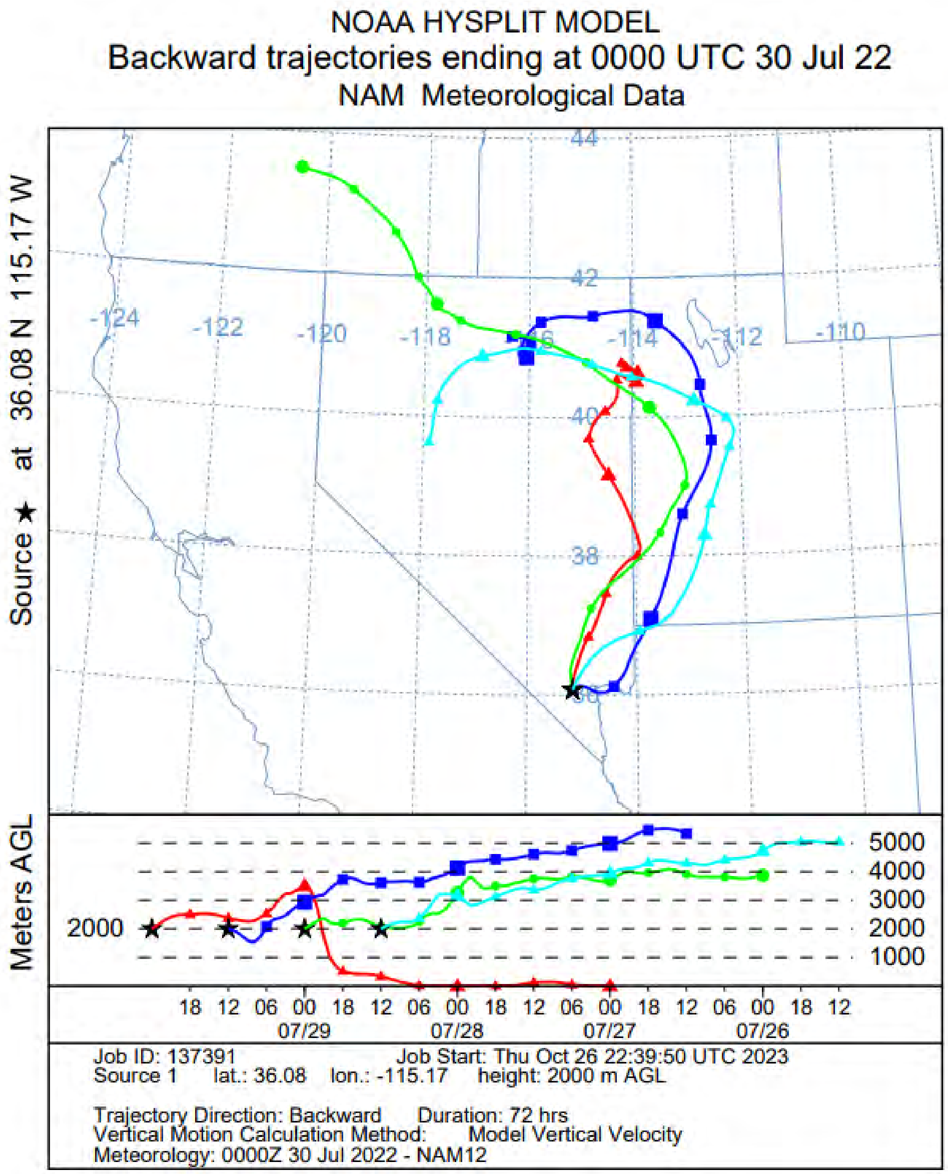

Figure 166. HYSPLIT back trajectories initiated at July 28, 2022, at 12:00 UTC (July 28 at 04:00 PST), July 29 at 00:00 UTC (July 28 at 16:00 PST), July 29 at 12:00 UTC (July 29 at 04:00 PST), and July 30 at 00:00 UTC (July 29 at 16:00 PST) using NAM 12 km meteorology. The back trajectories ran for 72 hours ending in Las Vegas (36.08, -115.17) at 2,000 m agl.

To assess the potential for smoke transport from fire locations, HYSPLIT dispersion modeling was performed from July 25 through July 29, 2022. Dispersion was initiated on July 25 at 11:00 PST from the two identified active fires and modeled through the exclusion dates to simulate smoke transport. Global Data Assimilation System (GDAS) data at 1.0° horizontal resolution was used for meteorological input. Output from the dispersion modeling is aggregated in 12-hr increments starting at July 27 at 23:00 PST through July 29 at 11:00 PST. This time period was chosen to correspond with the period of enhanced ozone measured in Clark County, NV. The accumulation of smoke in the boundary layer at 0-2,600 m is shown in Figure 167.

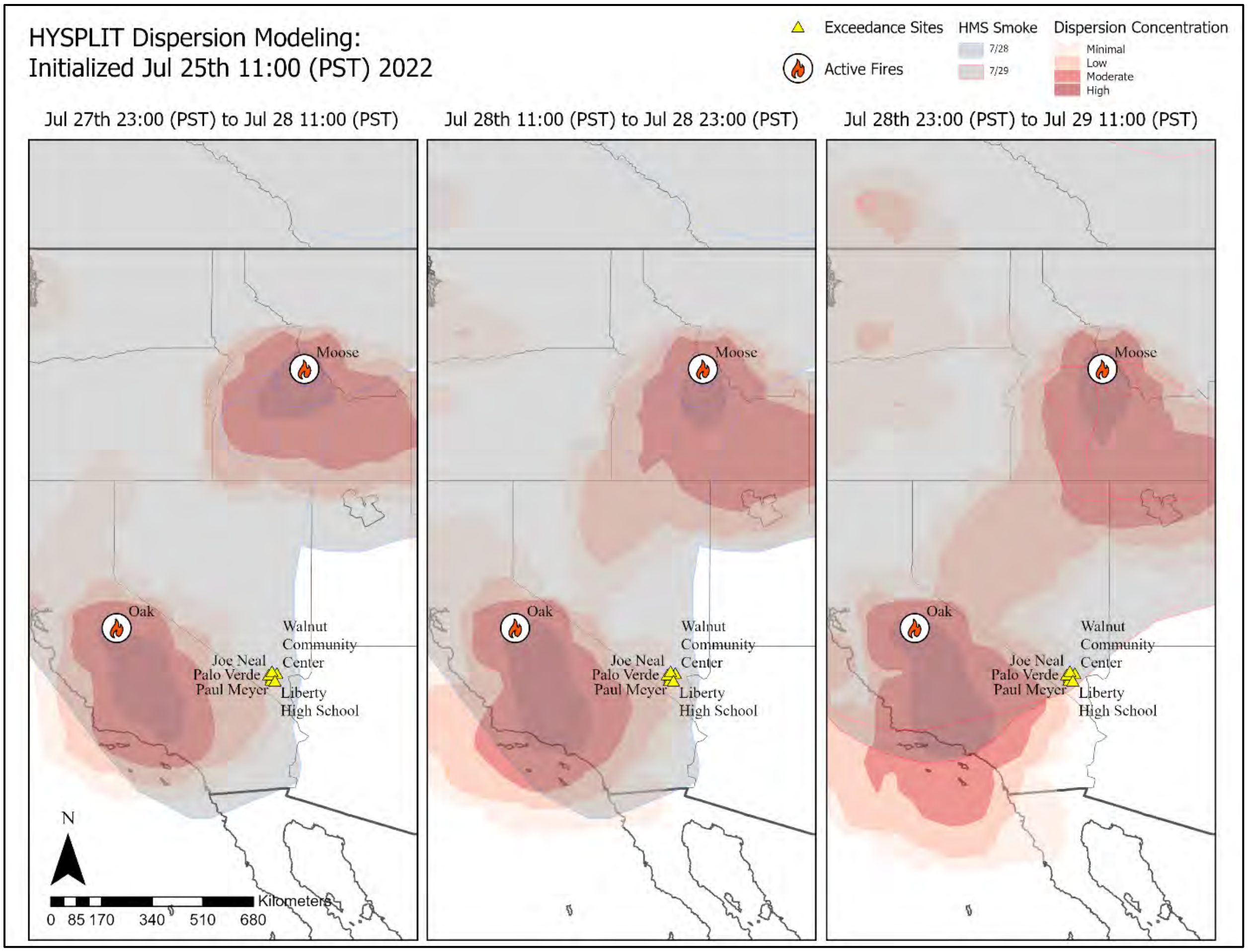

Figure 167. HYSPLIT dispersion modeling for two large fires (labeled as "Active Fires") in California and Idaho on or before the exclusion dates of July 28-29, 2022. GDAS 1.0° meteorological data was used, and dispersion was initiated on July 25 at 11:00 PST to model the regional smoke transport. HYSPLIT-modeled qualitative concentrations of particulate matter are shown in shades of red, and independently sourced HMS satellite-detection smoke plumes are shown in gray. HYSPLIT accumulation of particulate matter is shown at 0-2,600 m.

The HYSPLIT dispersion modeling shows that smoke from two fires produced dense layers of smoke that expanded over Nevada from July 28 into July 29, 2022 (red plumes, Figure 167). The modeling results, and eastern smoke perimeters, are consistent with the HMS smoke plume (shown by the gray layer in Figure 167), an independent smoke identification database. The HMS smoke plume extends farther to the north, likely due to additional smoke from Canadian fires that were not added to the dispersion modeling run. Dispersion modeling indicates that low concentrations of smoke from the Oak and Moose Fires would have entered Clark County during the day on July 28.

Consistent with this analysis, the HRRR smoke product. Figure 168 shows low levels of vertically integrated smoke over the Clark County region on July 28-29, 2022. Figure 169 provides meteorological reports (METAR) that show the stagnant conditions on July 29, allowing any wildfire smoke products to remain in the area and affect ozone on the following day. Note that there was one 30-min instance of high winds on the night of July 28 at 20:24 PST, due to a thunderstorm.

Taken together, the HMS smoke analysis, PBL analysis, HYSPLIT dispersion modeling, meteorological data, and HRRR forecast products suggest light regional smoke was merged between the California and Idaho fires, which was then transported southwest towards Clark County within the well-mixed boundary layer in on July 28, 2022. This smoke continued to affect ozone concentrations in Clark County on July 29 due to stagnation.

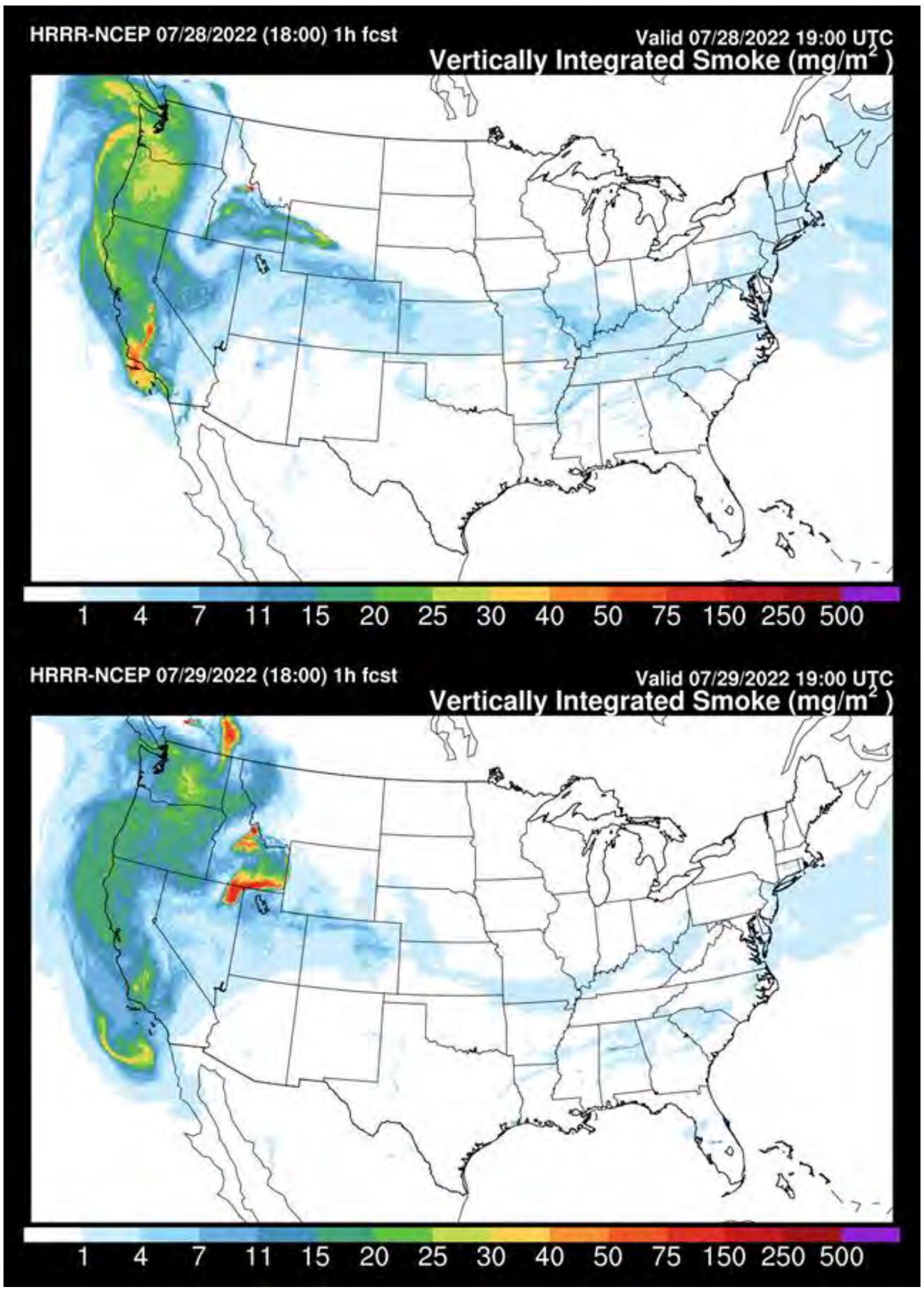

Figure 168. HRRR vertically integrated smoke forecast for July 28 and July 29, 2022, at 11:00 PST.

Time	Temperature	Dew Point	Humidity	Wind	Wind Speed	Wind Gust	Pressure	Precip.	Condition
12:53 AM	78 °F	68 °F	71 %	E	5 mph	0 mph	27.62 in	0.0 in	Fair
1:53 AM	77 °F	69 °F	76 %	E	7 mph	0 mph	27.61 in	0.0 in	Fair
2:53 AM	78 °F	67 °F	68 %	ENE	3 mph	0 mph	27.62 in	0.0 in	Fair
3:53 AM	77 °F	66 °F	69 %	ESE	8 mph	0 mph	27.64 in	0.0 in	Fair
4:53 AM	78 °F	66 °F	66 %	SSW	5 mph	0 mph	27.64 in	0.0 in	Fair
5:53 AM	79 °F	64 °F	60 %	CALM	0 mph	0 mph	27.64 in	0.0 in	Fair
6:53 AM	80 °F	65 °F	60 %	CALM	0 mph	0 mph	27.64 in	0.0 in	Fair
7:53 AM	82 °F	65 °F	56 %	CALM	0 mph	0 mph	27.64 in	0.0 in	Fair
8:53 AM	84 °F	63 °F	49 %	E	5 mph	0 mph	27.65 in	0.0 in	Fair
9:53 AM	87 °F	63 °F	44 %	VAR	5 mph	0 mph	27.64 in	0.0 in	Fair
10:53 AM	89 °F	61 °F	39 %	ESE	5 mph	0 mph	27.64 in	0.0 in	Fair
11:53 AM	92 °F	62 °F	37 %	ESE	8 mph	0 mph	27.62 in	0.0 in	Fair
12:53 PM	94 °F	62 °F	35 %	SE	7 mph	0 mph	27.60 in	0.0 in	Fair
1:53 PM	95 °F	61 °F	32 %	S	5 mph	0 mph	27.57 in	0.0 in	Fair
2:53 PM	98 °F	59 °F	27 %		0 mph	0 mph	27.55 in	0.0 in	Fair
3:53 PM	100 °F	58 °F	25 %	NE	5 mph	0 mph	27.52 in	0.0 in	Fair
4:53 PM	100 °F	58 °F	25 %	ESE	6 mph	0 mph	27.51 in	0.0 in	Fair
5:53 PM	100 °F	56 °F	23 %		0 mph	0 mph	27.52 in	0.0 in	Fair
6:53 PM	99 °F	56 °F	24 %	E	8 mph	0 mph	27.51 in	0.0 in	Fair
7:53 PM	98 °F	56 °F	24 %	E	10 mph	0 mph	27.51 in	0.0 in	Fair

Figure 169. METAR report at the Las Vegas International Airport (KLAS) for July 29, 2022, showing calm to light winds throughout the day.

5.3.4 Impacts at the Surface

Visible imagery is unavailable for this event due to a thunderstorm and an associated dust event late in the evening on July 27, 2022 (just before the exclusion days). Figure 170 shows METAR reports from July 27 showing the thunderstorm during the early morning hours.

Time	Temperature	Dew Point	Humidity	Wind	Wind Speed	Wind Gust	Pressure	Precip.	Condition
6:53 PM	95 °F	61 °F	32 %	S	8 mph	0 mph	27.57 in	0.0 in	Fair
7:32 PM	87 °F	61 °F	41 %	NE	43 mph	59 mph	27.62 in	0.0 in	Haze / Windy
7:38 PM	85 °F	62 °F	46 %	NE	33 mph	59 mph	27.65 in	0.0 in	Light Rain / Windy
7:53 PM	84 °F	61 °F	46 %	NE	33 mph	46 mph	27.65 in	0.0 in	Cloudy / Windy
8:32 PM	81 °F	63 °F	54 %	NE	29 mph	46 mph	27.68 in	0.0 in	Thunder in the Vicinity
8:53 PM	81 °F	62 °F	52 %	NE	18 mph	35 mph	27.68 in	0.0 in	Thunder in the Vicinity
9:15 PM	81 °F	62 °F	52 %	VAR	5 mph	0 mph	27.72 in	0.0 in	Light Rain
9:53 PM	80 °F	64 °F	58 %	S	7 mph	0 mph	27.70 in	0.0 in	Light Rain
10:53 PM	80 °F	66 °F	62 %	ENE	3 mph	0 mph	27.67 in	0.0 in	Light Rain
11:53 PM	78 °F	68 °F	71 %	ENE	3 mph	0 mph	27.64 in	0.0 in	Fair

Figure 170. METAR report at the Las Vegas International Airport (KLAS) during the evening of July 27, 2022, showing the thunderstorm associated with the dust event.

In this section, we provide the pollutant concentrations at each affected site; however, the evening thunderstorm on July 27, 2022, obscures any useful $PM_{2.5}$ concentrations information. In cases like this, with longer range smoke transport and non-local fires, $PM_{2.5}$ is more likely to be dispersed and thus less likely to be significantly enhanced. In this case, however, hourly $PM_{2.5}$ concentrations did exceed the diurnal 90th percentile $PM_{2.5}$ concentration at multiple sites in the Las Vegas Valley between 18:00 and 19:00 PST on July 27 due to outflow from the approaching thunderstorm (**Figure 171**). The $PM_{2.5}/PM_{10}$ ratios for this event at all sites throughout Clark County (**Figure 172 and Figure 173**) showed the decrease of the $PM_{2.5}/PM_{10}$ ratio during the thunderstorm and outflow boundary event in the late evening on July 27, consistent with a dust storm. After the dust storm concluded by early morning July 28, the ratio increased and stayed above average for most sites during the rest of the daytime on July 28. The Virgin Valley site (which would be the first site to experience smoke from the California/Idaho fires due to its location in the far northeast corner of Clark County, outside the Las Vegas Valley) experienced values for the $PM_{2.5}/PM_{10}$ ratio well above the 95th percentile for the rest of the daytime period on July 28. While the $PM_{2.5}/PM_{10}$ ratio at most sites did not increase above the 95th percentile, neither did the absolute $PM_{2.5}$ concentrations (Figure 171). This is again likely due to smoke dispersion during longer range transport, where $PM_{2.5}$ is more likely to be dispersed and not significantly enhanced.

Figure 174 shows the hourly CO concentrations alongside the 10th-90th percentile diurnal concentrations, calculated from 2017-2022, recorded at the event-affected sites that measure CO concentrations. Hourly CO concentrations were equal to or greater than the diurnal 90th percentile CO concentrations recorded at the Paul Meyer and Joe Neal sites during the afternoon of July 28.

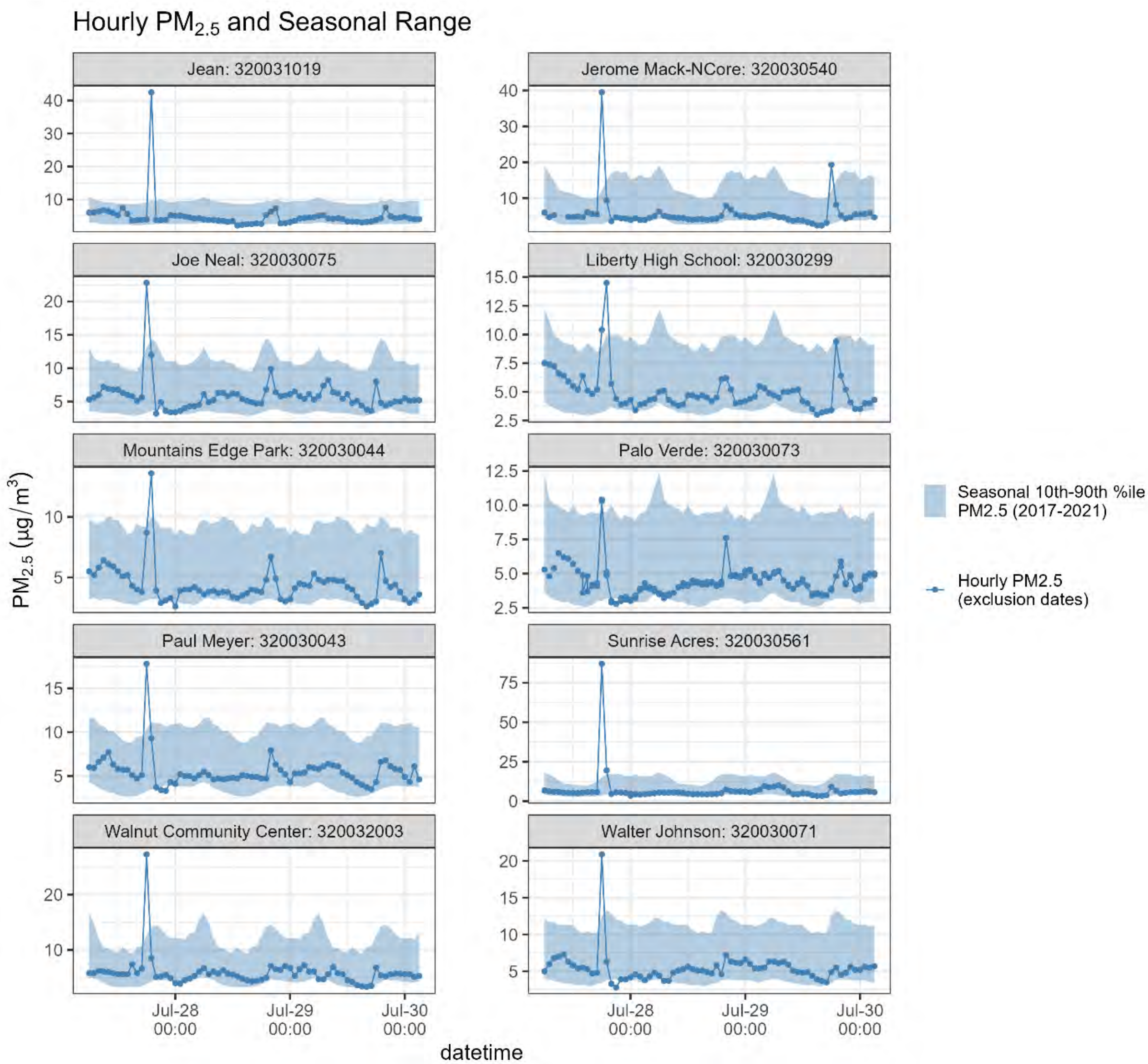

Figure 171. Hourly $PM_{2.5}$ measurements overlaid on the 10th-90th percentile diurnal concentration recorded at the event-affected measurement sites and supporting sites that measure $PM_{2.5}$ concentrations. The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2022.

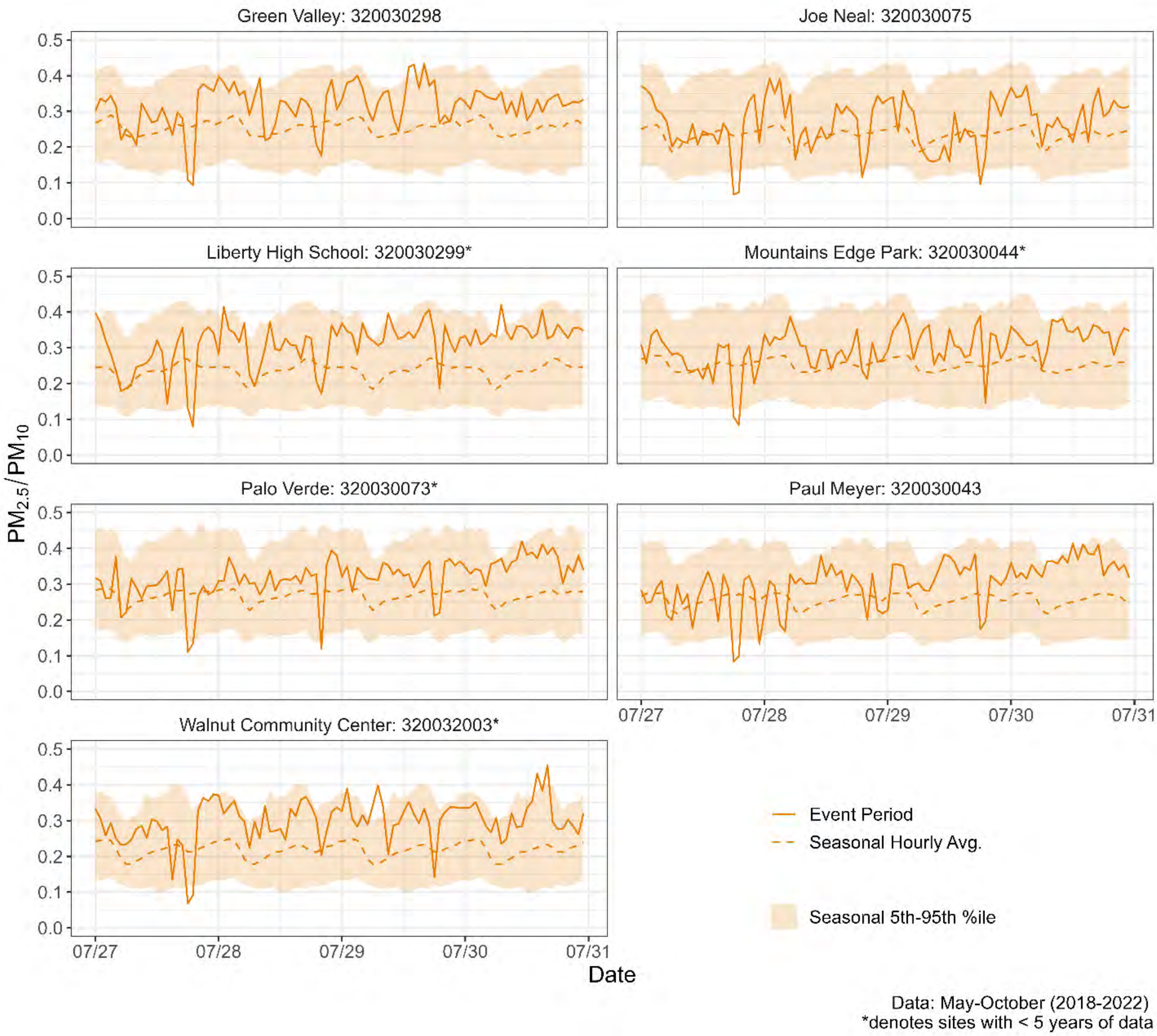

Figure 172. Ratio of $PM_{2.5}/PM_{10}$ concentrations recorded at the Green Valley, Joe Neal, Liberty High School, Mountains Edge Park, Palo Verde, Paul Meyer, and Walnut Community Center sites during the July 28-29, 2022, event period. The 5-yr average $PM_{2.5}/PM_{10}$ diurnal ratio is displayed as a dotted line, and the 5th-95th percentile range is shown as a shaded ribbon. The 5th-95th percentile concentration is calculated across the ozone production season (May-October) of 2018-2022.

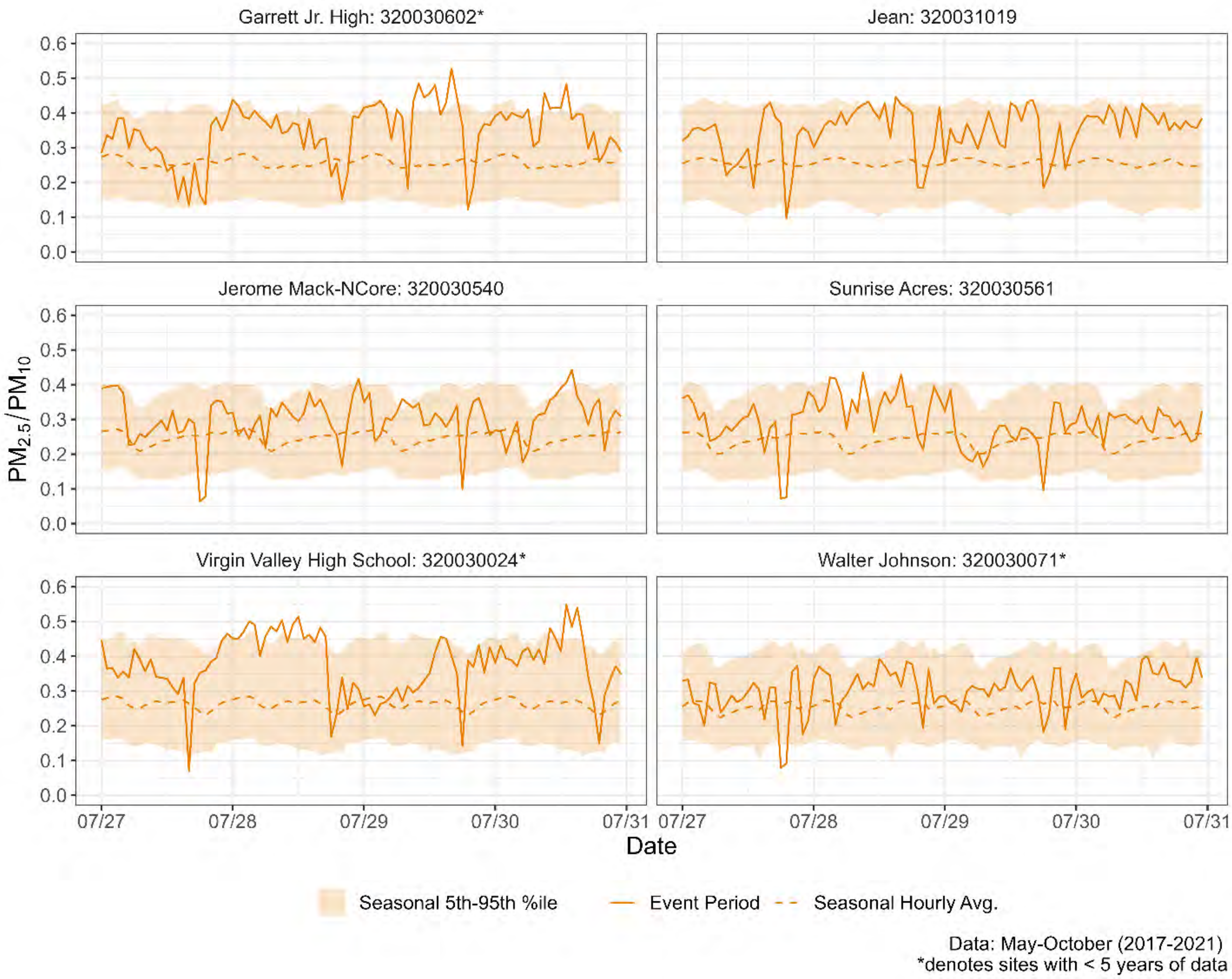

Figure 173. Ratio of $PM_{2.5}/PM_{10}$ concentrations recorded at the Garrett Jr. High, Jean, Jerome Mack, Sunrise Acres, Virgin Valley High School, and Walter Johnson monitoring sites during the July 28-29, 2022, event period. The 5-yr average $PM_{2.5}/PM_{10}$ diurnal ratio is displayed as a dotted line, and the 5th-95th percentile range is shown as a shaded ribbon. The 5th-95th percentile concentration is calculated across the ozone production season (May-October) of 2018-2022.

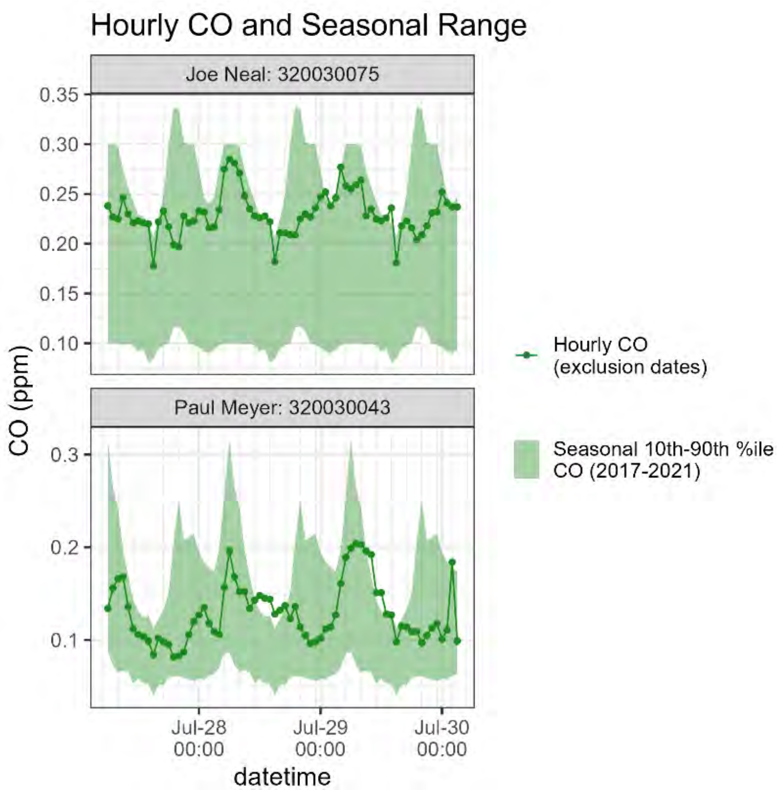

Figure 174. Hourly CO measurements overlaid on the 10th-90th percentile diurnal concentrations recorded at each event-affected measurement site that measures CO concentrations. The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2022.

5.3.5 Event Statistics

Table 37 summarizes the daily measurements of ozone, $PM_{2.5}$, CO, and NO_2 concentrations on the July 28-29, 2022, exclusion days, as well as the percentile rank of the observations compared to the previous five years of data (2018-2022) at both sites. Ozone MDA8 measurements at all sites were above the 97th percentile. $PM_{2.5}$, CO, and NO_2 concentrations are not significantly enhanced above typical concentrations during this event, likely due to light smoke conditions. 24-hr average $PM_{2.5}$ concentrations ranged from the 21st - 41st percentile at the sites. CO and NO_2 1-hr daily maximum concentrations ranged from the 30th-50th percentile. Lower concentrations of co-pollutants are more consistent with longer-range smoke transport and upwind ozone formation and transport. They may also occur when there is transport of ozone precursors in the Las Vegas urban area without significantly impacting other pollutants.

Table 37. Percentile of pollutant measurements on the July 28-29, 2022, exclusion days compared with most recent five years of pollutant concentration data (2018-2022).* The percentile rank is calculated across the ozone production season (May 1-October 31) of 2018-2022.

Date	Site Name	Site Code	Ozone		$PM_{2.5}$		CO		NO_2	
			Ozone MDA8 (ppb)	Percent Rank	$PM_{2.5}$ 24-hr Avg (µg/m^3)	Percent Rank	CO 1-hr Daily Max (ppb)	Percent Rank	NO_2 1-hr Daily Max (ppb)	Percent Rank
7/28/2022	Joe Neal	320030075	73	97.6	5.4	41.2	285	49.9*	11.4	32.9
7/28/2022	Liberty High School	320030299	72	98.1*	4.4	21.5*				
7/28/2022	Mountains Edge Park	320030044	74	98.5*	3.8	22.3*				
7/28/2022	Palo Verde (POC 3)	320030073	81	99.9	4.2	28.1*				
7/28/2022	Palo Verde (POC 4)	320030073	--	--	4.1	25.9*				
7/28/2022	Paul Meyer	320030043	77	99	5	31.4	196	36.6*		
7/28/2022	Walter Johnson	320030071	78	99.3	4.9	27.8*				
7/29/2022	Palo Verde (POC 3)	320030073	71	97.8	4.4	32.8*				
7/29/2022	Palo Verde (POC 4)	320030073	--	--	4.3	30.5*				

*Sites that have less than five years of data available for a given parameter.

5.4 September 1-2, 2022

5.4.1 Event Summary

An ozone event took place across September 1-2, 2022, and affected the Paul Meyer monitoring site in Clark County, Nevada. The MDA8 ozone concentration was 74 ppb on September 1, and 73 ppb on September 2. While only the Paul Meyer site recorded MDA8 values above the NAAQS threshold during this event, sites throughout the Las Vegas Valley experienced MDA8 values ranging from 51 to 74 ppb (with an average of 63 ppb) on September 1, and MDA8 values ranging from 53 to 73 (with an average of 63 ppb) on September 2. Regional wildfire smoke is suspected to have contributed to the NAAQS exceedances these days. Major evidence includes smoke detection maps from NOAA's HMS smoke detection, dispersion model results from the HYSPLIT, meteorological analyses, PBL analyses, and a reduction in visibility recorded by ground-based cameras. This combination of evidence suggests that this could be an unrepresentative event for base and future design value ozone assessments.

A time series graph for August 31-September 4, 2022, is provided in Figure 175, showing hourly ozone concentrations that exceeded the hourly seasonal means and 10th-90th percentiles (calculated using May 1-October 31, 2017-2021) at the Paul Meyer site.

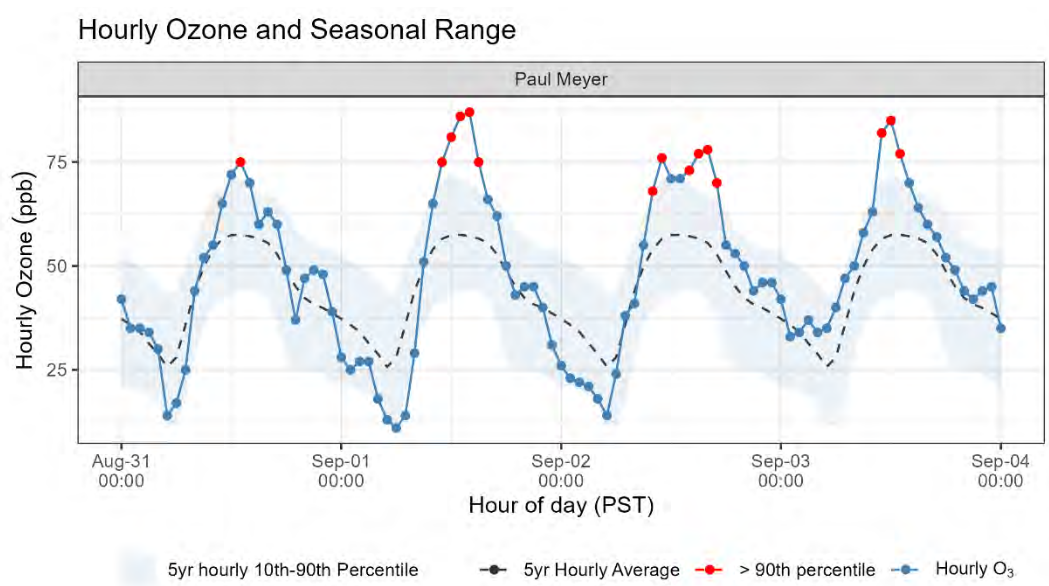

Figure 175. Hourly ozone concentrations (ppb) recorded at the Paul Meyer site across August 31-September 4, 2022, compared to 5-yr ozone season (May 1-October 31) hourly means and 10-90th percentiles.

5.4.2 Identification of Wildfires

Figure 176 shows HMS maps that display the progression of smoke dispersion across the United States between August 30 and September 2, 2022. HMS smoke maps are created using visible satellite imagery from Geostationary Operational Environmental Satellites (GOES). Visible imagery is only available during the sunlit part of the GOES orbit; therefore, smoke movement during nighttime hours is inferred between the daylight-generated smoke maps. On August 30, smoke plumes from fires in the northwest U.S. traveled northward and eastward. Over the next few days, these smoke plumes dispersed and spread over most of the western U.S. in a clockwise direction, driven by a surface and upper-level high-pressure system. HMS smoke was present over Clark County, Nevada, on September 1 and 2. Figure 177 and Figure 178 show the surface-level and 500-mb weather maps for the days corresponding to the HMS maps in Figure 176. The weather maps show a surface and upper-level high pressure system over the southwest U.S. and moving to center over Clark County from August 30 through September 2. Since high-pressure systems are associated with stagnant and sinking air, this may have resulted in smoke aloft reaching the ground level.

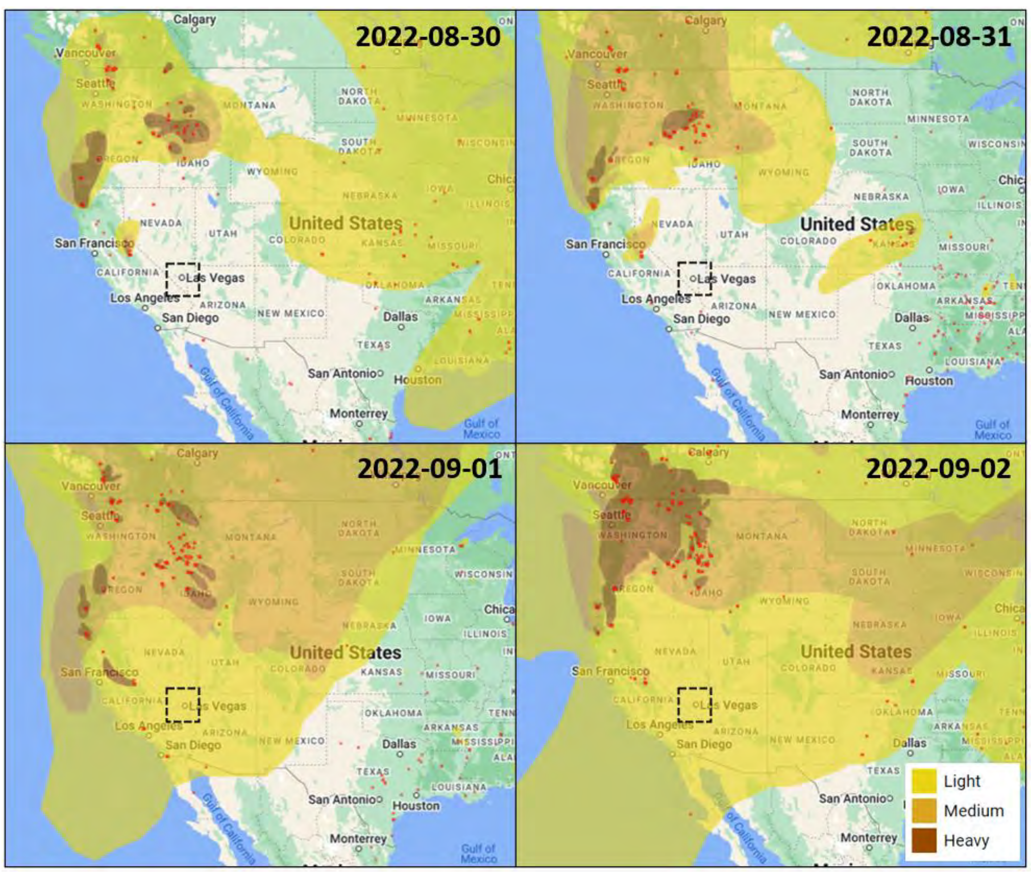

Figure 176. HMS smoke maps for August 30-September 2, 2022, showing smoke transport and qualitative smoke density. Clark County, NV, is enclosed by a dashed, black box on each map.

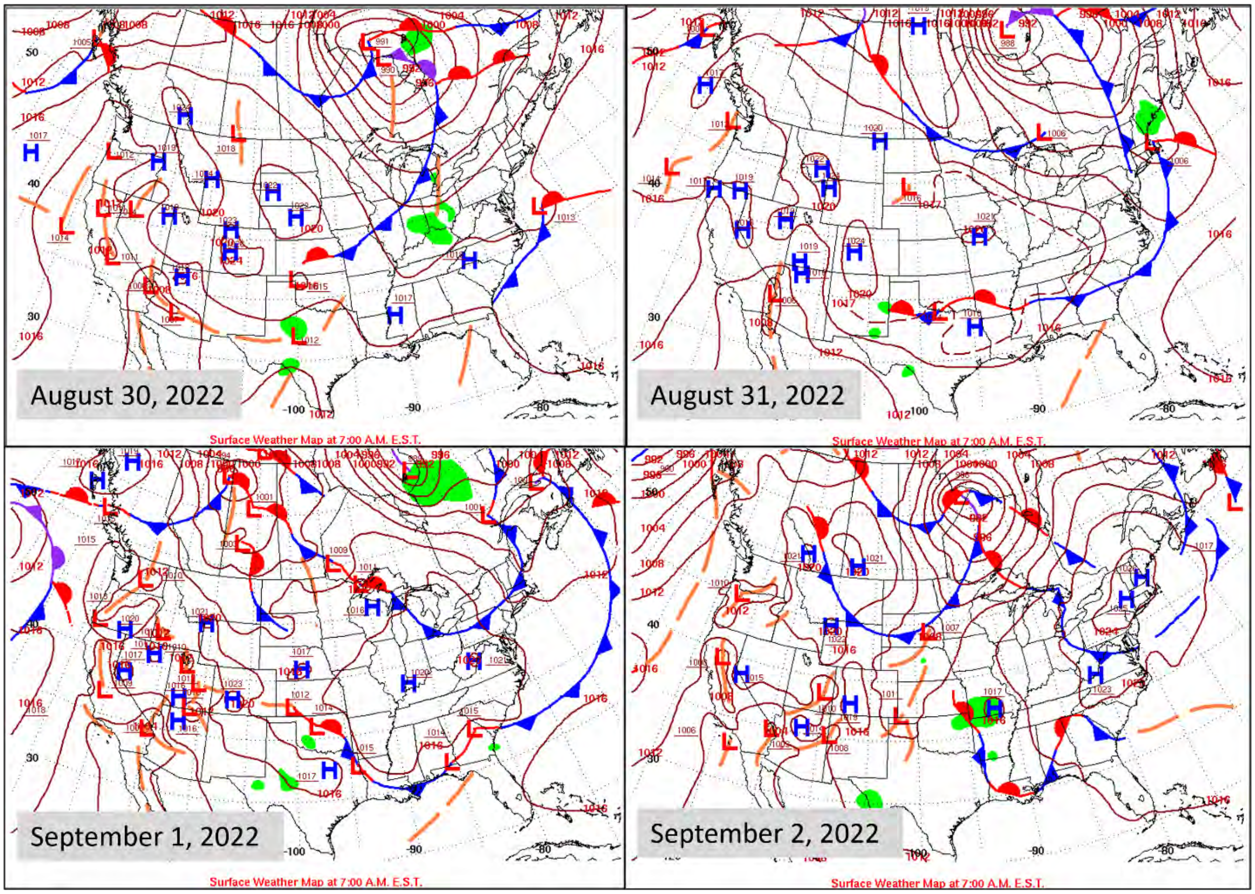

Figure 177. Daily surface-level weather maps for August 30-September 2, 2022.

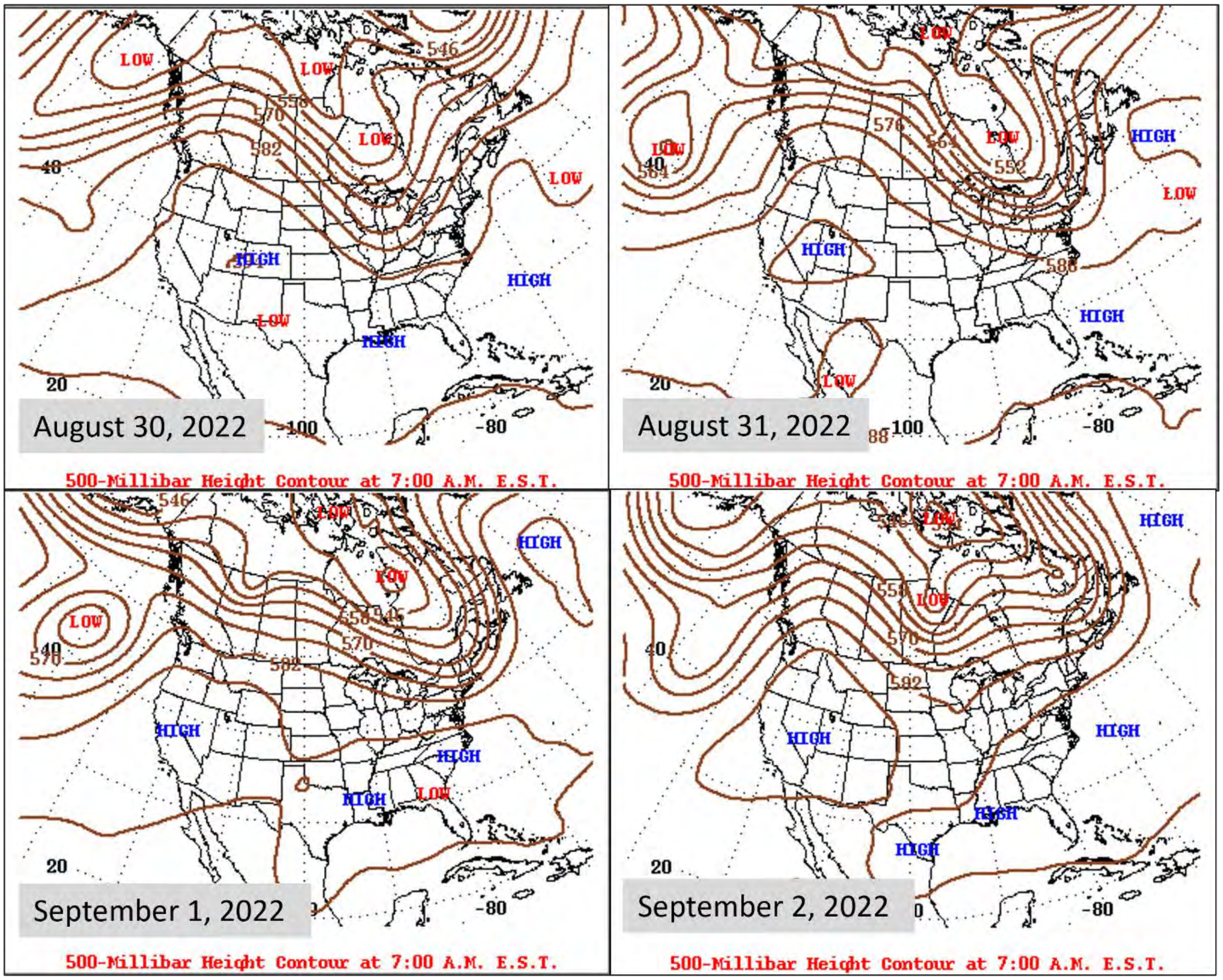

Figure 178. Daily 500-mb weather maps for August 30-September 2, 2022.

Seventeen wildfires were active in the western and northwestern U.S. during the days leading up to and including the exclusion dates and are recorded in Table 38. The active fire area for each fire on and before the exclusion dates is provided, based on a post from the Six Rivers National Forest U.S. Forest Service account and InciWeb data for all 17 fires. Fire perimeters for each fire in relation to Clark County are shown in Figure 179. Zoomed-in views of most of the fires are shown in Figure 180 through Figure 182. Although the fires range in size, the HMS smoke images suggest that regional smoke was generated and spread due to the high volume of fire activity in the western U.S., including California, Oregon, and Idaho.

Table 38. Wildfires affecting Clark County on the exclusion days of September 1-2, 2022. The fire name, state location, total acreage, acres burned on or before the exclusion days, and the start and containment dates are included. Italicized containment dates indicate fire "out" status.

Wildfire Name	State	Total Acres	Acres Burned on or Before Exclusion Days	Start Date	Containment Date
Campbell (Lightning Complex)	California	41,540	37,081 (Sept. 1)[43]	Aug. 5	Nov. 3
Cedar Creek	Oregon	128,602	8,817 (Sept. 1)[44]	Aug. 1	Nov. 1
Crockets Knob	Oregon	4,333	2,840 (Sept. 1)[45]	Aug. 22	Oct. 27
Dismal	Idaho	8,197	1,876 (Aug. 31)[46]	July 23	Nov. 3
Double Creek	Oregon	175,938	2,946 (Sept. 1)[47]	Aug. 30	Oct. 25
Four Corners	Idaho	13,703	12,817 (Sept. 1)[48]	Aug. 13	Oct. 20
Moose	Idaho	130,144	99,232 (Sept. 1)[49]	July 17	Nov. 09
Nebo	Oregon	12,608	3,086 (Sept. 1)[50]	Aug. 25	Oct. 25
Norton	Idaho	9,080	1,859 (Aug. 29)[51]	Aug. 1	Oct. 25
Patrol Point	Idaho	16,130	735 (Sept. 1)[52]	Aug. 20	Nov. 03
Rum Creek	Oregon	21,227	15,635 (Sept. 1)[53]	Aug. 17	Sep. 30
Sturgill	Oregon	21,636	4,815 (Sept. 1)[54]	Aug. 22	Oct. 24
Trail Ridge	Montana	17,509	517 (Sept. 1)[55]	Aug. 26	Oct. 29
Williams Creek	Idaho	16,083	626 (Sept. 1)[56]	Aug. 29	Nov. 3
Ross Fork	Idaho	37,928	1,944 (Sept. 1)[57]	Aug. 14	Nov. 1
Red	California	8,408	3,558 (Sept. 1)[58]	Aug. 4	*Nov. 6*
Rodgers	California	2,774	1,644 (Sept. 1)	Aug. 8	*Nov. 6*

[43] https://www.facebook.com/plugins/post.php?href=https%3A%2F%2Fwww.facebook.com%2FSixRiversNF%2Fposts%2Fpfbid0Yth9ZfKE3izWXzkn3wDoMyuDm4iHKgKf7CYoUVGasnxAU4MkhNTPfutK9ii7KsMul&
[44] https://inciweb.nwcg.gov/incident-publication/orwif-cedar-creek-fire/cedar-creek-fire-update-sept-1
[45] https://inciweb.nwcg.gov/incident-publication/ormaf-crockets-knob-fire/912022-crockets-knob-fire-update
[46] https://inciweb.nwcg.gov/incident-maps-gallery/idpaf-dismal-fire?page=0
[47] https://inciweb.nwcg.gov/incident-information/orwwf-double-creek-fire
[48] https://inciweb.nwcg.gov/incident-information/idpaf-four-corners-fire
[49] https://inci-web-media-bucket.s3.us-gov-west-1.amazonaws.com/s3fs-public/2022-10/pict20220805-153223-0.pdf
[50] https://incitest.nwcg.gov/incident-information/orwwf-nebo-fire
[51] https://inci-web-media-bucket.s3.us-gov-west-1.amazonaws.com/s3fs-public/2022-10/pict20220805-153223-0.pdf
[52] https://incitest.nwcg.gov/incident-information/idpaf-patrol-point
[53] https://inciweb.nwcg.gov/incident-maps-gallery/ormed-rum-creek-fire?page=2
[54] https://inciweb.nwcg.gov/incident-maps-gallery/orwwf-sturgill-fire?page=3
[55] https://inciweb.nwcg.gov/incident-information/mtbdf-trail-ridge-fire
[56] https://inciweb.nwcg.gov/incident-information/idncf-williams-creek-fire
[57] https://inciweb.nwcg.gov/incident-information/idstf-ross-fork
[58] https://www.facebook.com/YosemiteFire/posts/5724107654307870?ref=embed_post

Figure 179. Final fire perimeters (red) for the 17 active fire regions during the September 1-2, 2022, exclusion dates in relation to Clark County (black perimeter).

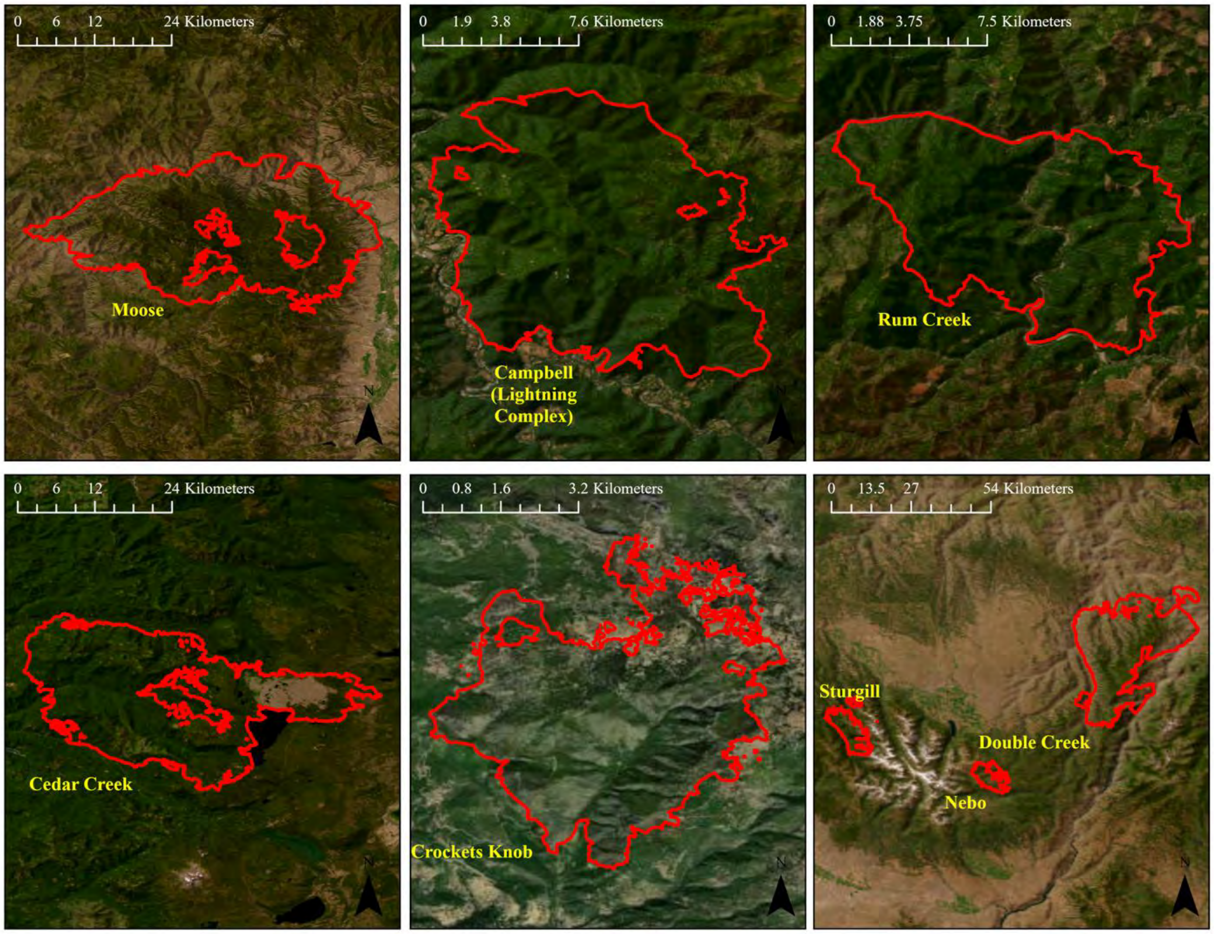

Figure 180. Final fire perimeters (red) for six of the 17 active fire regions during the September 1-2, 2022, exclusion dates.

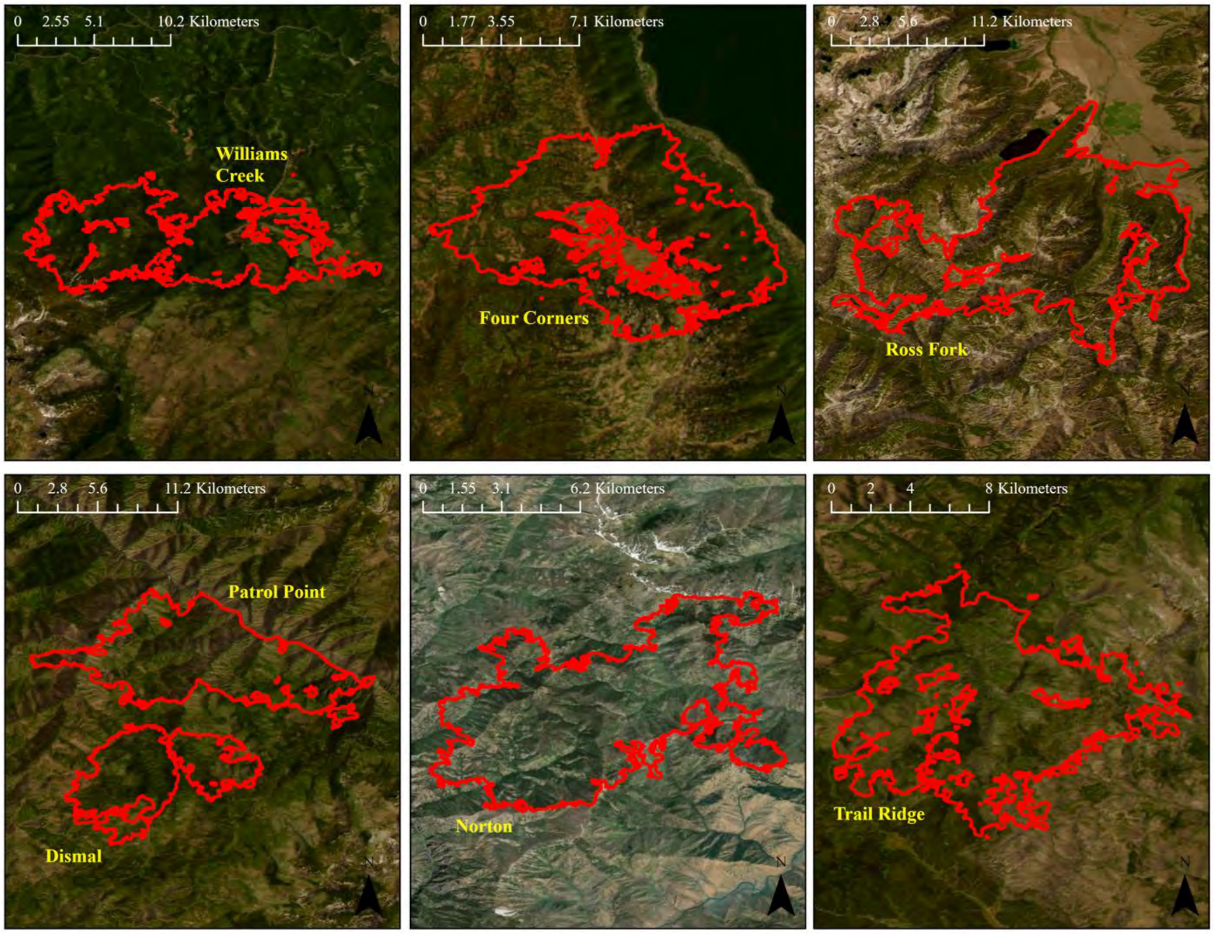

Figure 181. Final fire perimeters (red) for six of the 17 active fire regions during the September 1-2, 2022, exclusion dates.

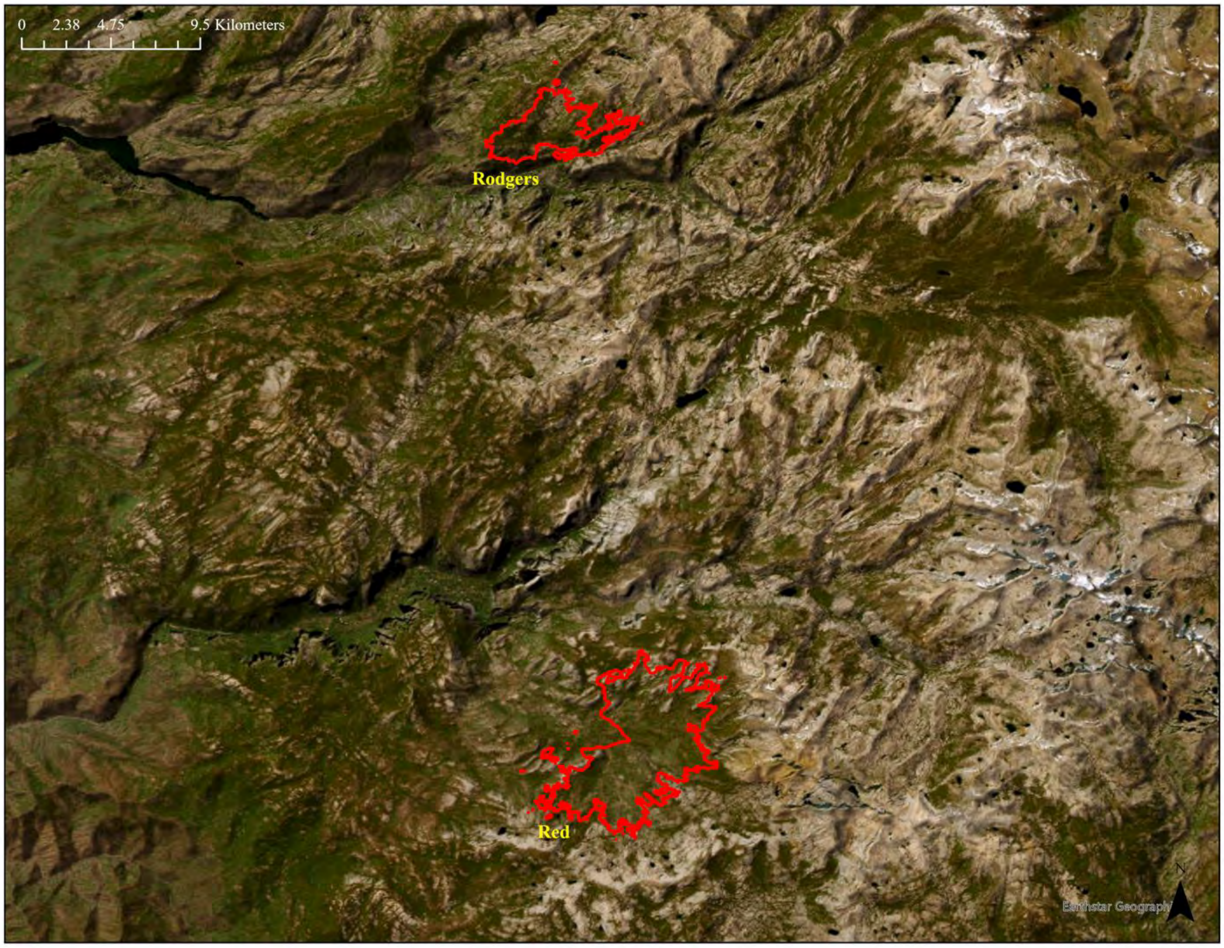

Figure 182. Final fire perimeters (red) for two of the 17 active fire regions during the September 1-2, 2022, exclusion dates.

5.4.3 Dispersion Modeling and Regional Analysis

To examine the effect of wildfire smoke in Clark County (as indicated by the HMS smoke maps shown in Section 5.4.2), we first determined the meteorological conditions on and before the September 1-2 event. We specifically focused on the boundary layer dynamics to determine the depth of mixing and possibility of smoke mixing to the surface. We then used this information to model smoke via HYSPLIT and compare the results to independent data sources (including HMS and HRRR data).

The PBL denotes the atmospheric layer closest to the surface, and the height of the PBL describes the vertical extent of surface air characteristics. Atmospheric soundings and PBL maps provide visualizations of the extent of vertical mixing in the lower troposphere. The five skew-T diagrams in Figure 183 show the vertical profile of the atmosphere every 12 hours from September 1 at 00:00 UTC (August 31 at 16:00 PST) to September 3 at 00:00 UTC (September 2 at 16:00 PST). The five skew-T diagrams are characterized primarily by their diurnal changes in the lower troposphere from consecutive soundings. Soundings taken at 12:00 UTC (i.e., 04:00 PST) show a near-surface temperature inversion that inhibited vertical mixing between the near-surface and mid-troposphere due to low PBL heights, whereas soundings taken at 16:00 PST show an approximately dry-adiabatic temperature lapse rate, indicating that the lower troposphere was well mixed with a PBL of approximately 4,000 to 6,000 m on each day (~500-600 mbar). The NAM-modeled PBL heights over Clark County on September 1 at 16:00 PST (**Figure 184**) and September 2 at 16:00 PST (**Figure 185**) correspond to the PBL heights shown on the sounding taken at these same times, and also indicate a PBL height of approximately 4,000 to 6,000 m. Both the skew-T diagrams and NAM-modeled PBL heights over Clark County on the exclusion dates indicate a deep, well-mixed boundary layer on each afternoon, conducive to smoke mixing to the surface.

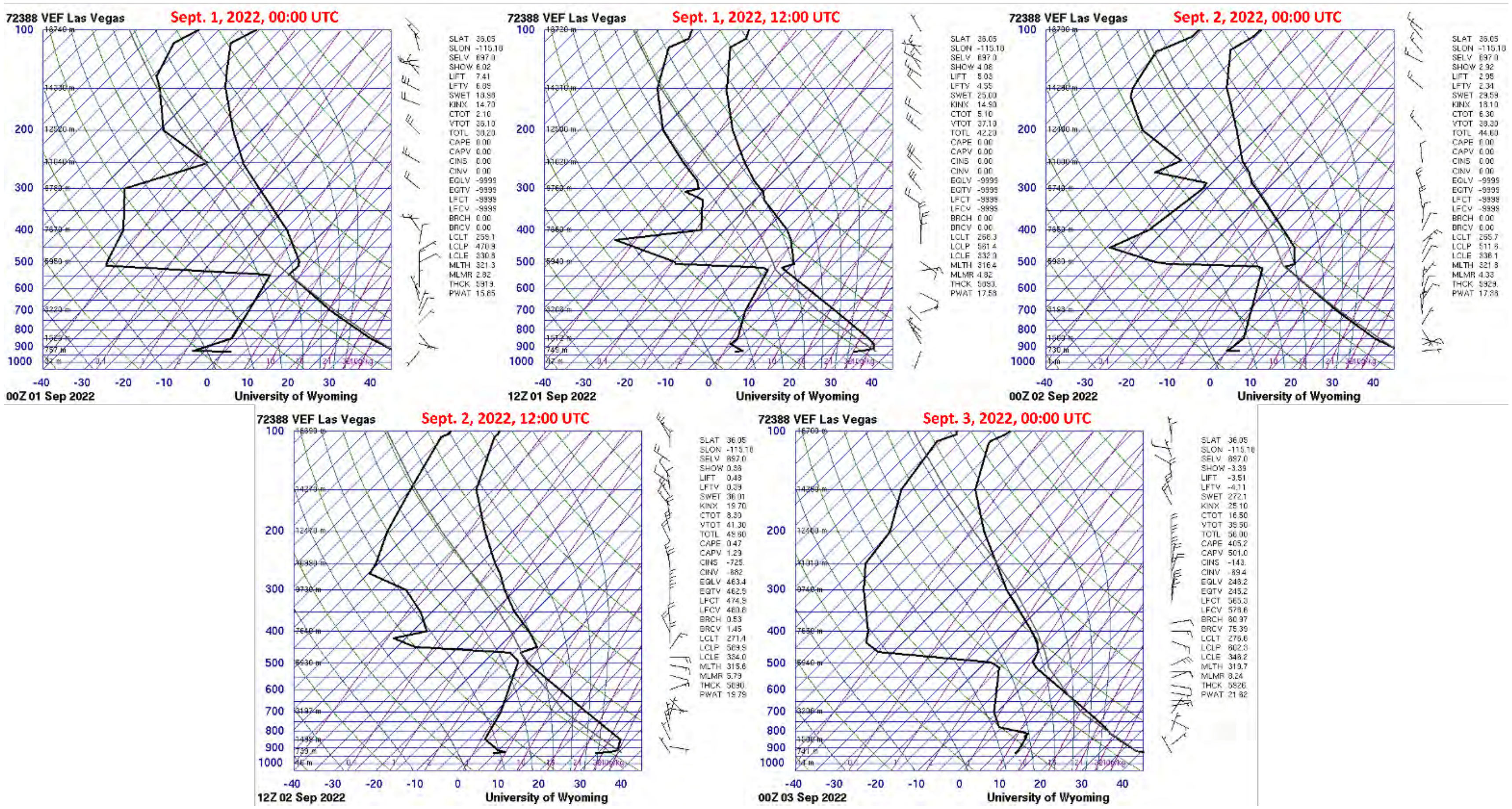

Figure 183. Skew-T soundings launched from the Las Vegas National Weather Service Office from September 1, 2022, at 00:00 UTC (August 31 at 16:00 PST) (top left), to September 3 at 00:00 UTC (September 2 at 16:00 PST) (bottom right).

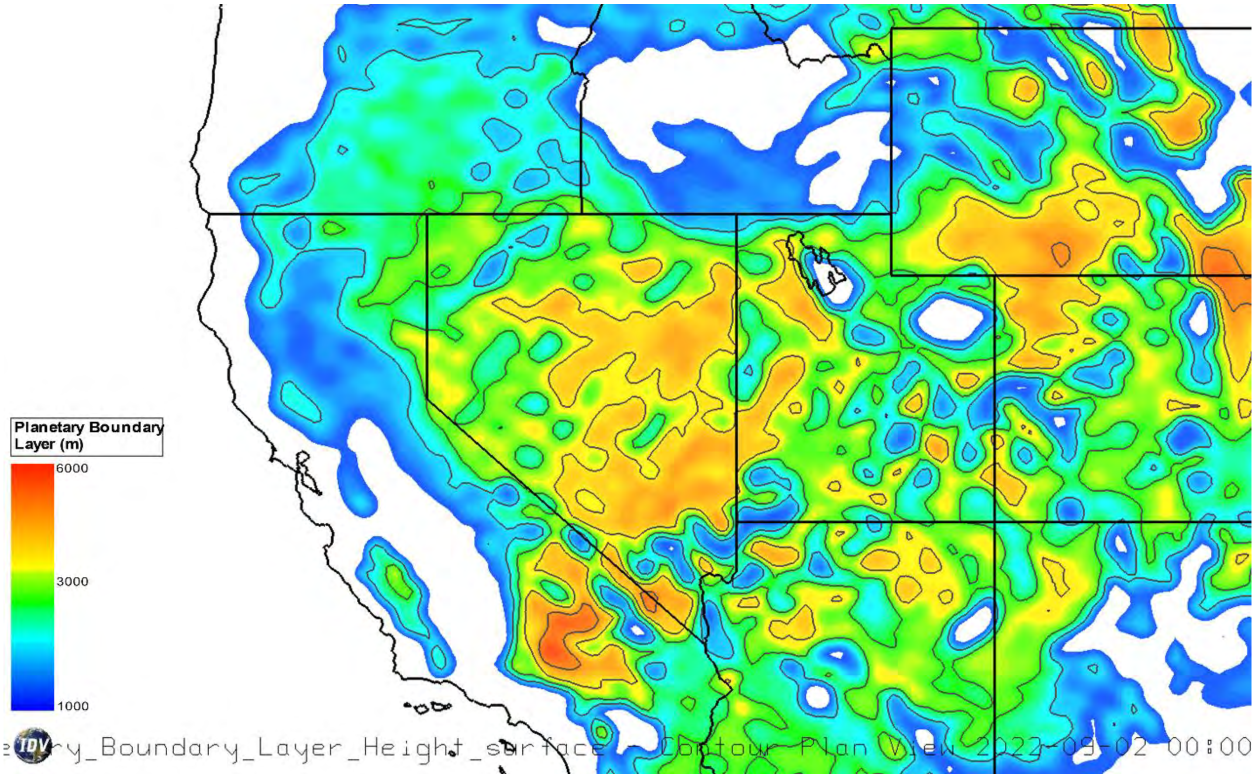

Figure 184. PBL height contour map based on the NAM model for September 2, 2022, at 00:00 UTC (September 1 at 16:00 PST). The gray lines denote PBL heights above 2 km in altitude in 1 km increments. Color contours start at 1 km.

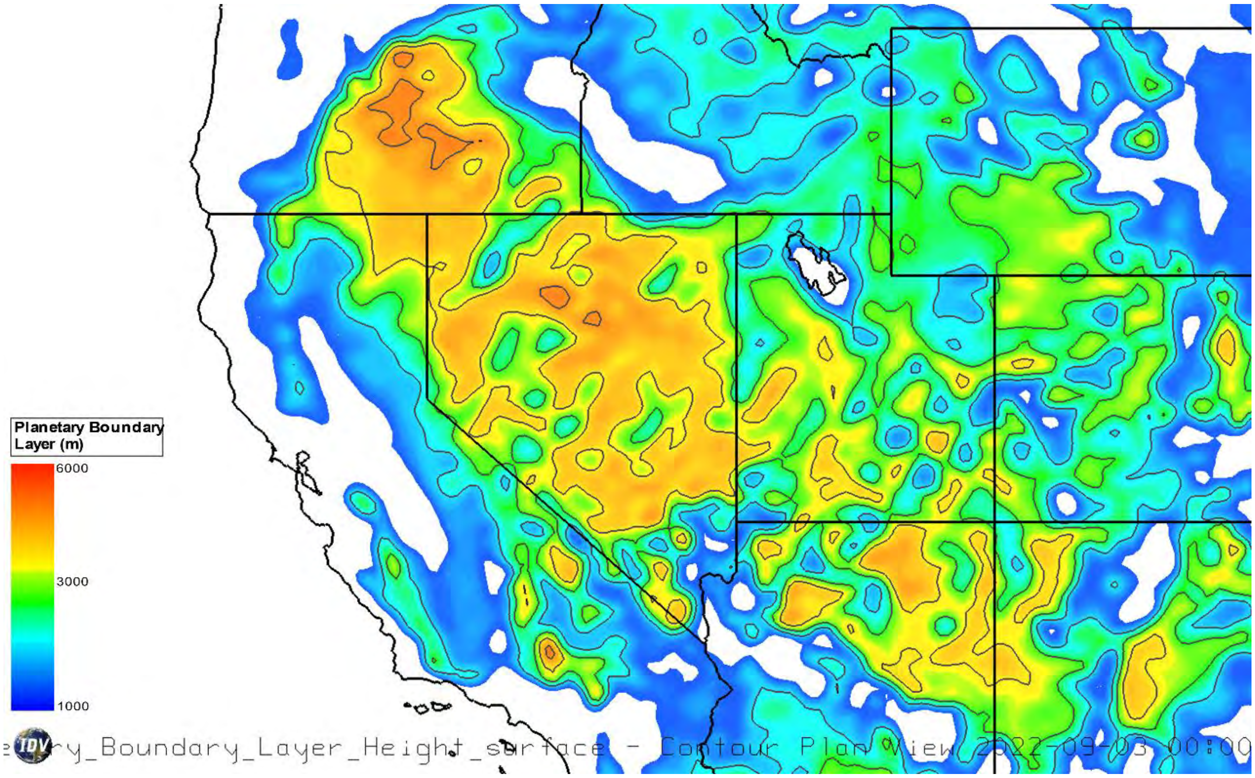

Figure 185. PBL height contour map based on the NAM model for September 3, 2022, at 00:00 UTC (September 2 at 16:00 PST). The gray lines denote PBL heights above 2 km in altitude in 1 km increments. Color contours start at 1 km.

HYSPLIT dispersion modeling was performed from August 30 through September 3, 2022. Dispersion modeling was initiated on August 30 at 00:00 PST from the 17 identified active fires impacting the exclusion dates, and modeled through the exclusion dates to simulate the smoke patterns seen in satellite imagery and HMS smoke data. Global Data Assimilation System (GDAS) data at 1.0° horizontal resolution was used for meteorological input. Output from the dispersion modeling has been integrated over 6-hr periods starting 00:00 PST on September 1, and ending 00:00 PST on September 3. This time period was chosen to correspond with the exclusion dates. The accumulation of smoke throughout the boundary layer at 0-4,500 m for the time periods are shown in Figure 186. The modeling results are somewhat consistent with the HMS smoke plume shown in Figure 176; HMS is an independent smoke identification database. The results likely miss some smoke from additional fires in the western U.S. and Canada that were burning at or before the exclusion dates.

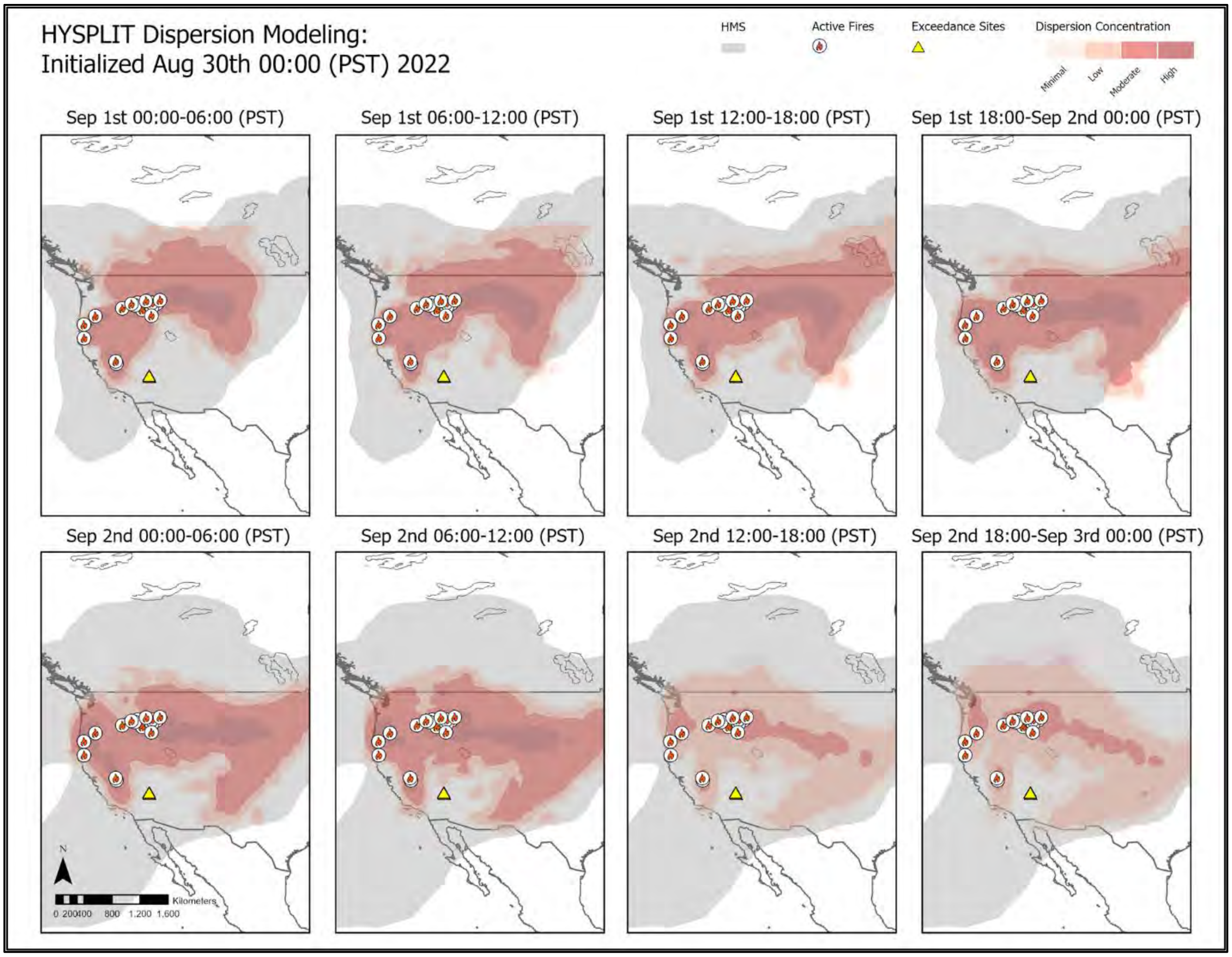

Figure 186. HYSPLIT dispersion modeling for 17 large fires (labeled as "Active Fires") in the western U.S. on or before the exclusion dates of September 1-2, 2022. GDAS 1.0° meteorological data was used, and dispersion was initiated on August 30, at 00:00 PST to model the regional smoke observed in satellite and HMS products. HMS smoke is shown in gray, and qualitative concentrations of particulate matter are shown in shades of red. Accumulation of particulate matter is shown at 0-4,500 m.

A HYSPLIT back trajectory was performed for 16:00 UTC (08:00 PST) on September 1, 2022, shown in Figure 187. The back trajectory shows the general pattern of air from the western U.S. fires, through the resulting regional smoke plume, and finally the descent of air from high altitude into the boundary layer in the Las Vegas area on the morning on September 1; this brought smoke and associated ozone precursors into the area, setting up for enhanced ozone production on September 1 and 2. This is consistent with the HMS and meteorological narrative from Section 5.4.2, and shows air circling around a high-pressure system in the southwestern U.S. and descending into a well-mixed boundary layer.

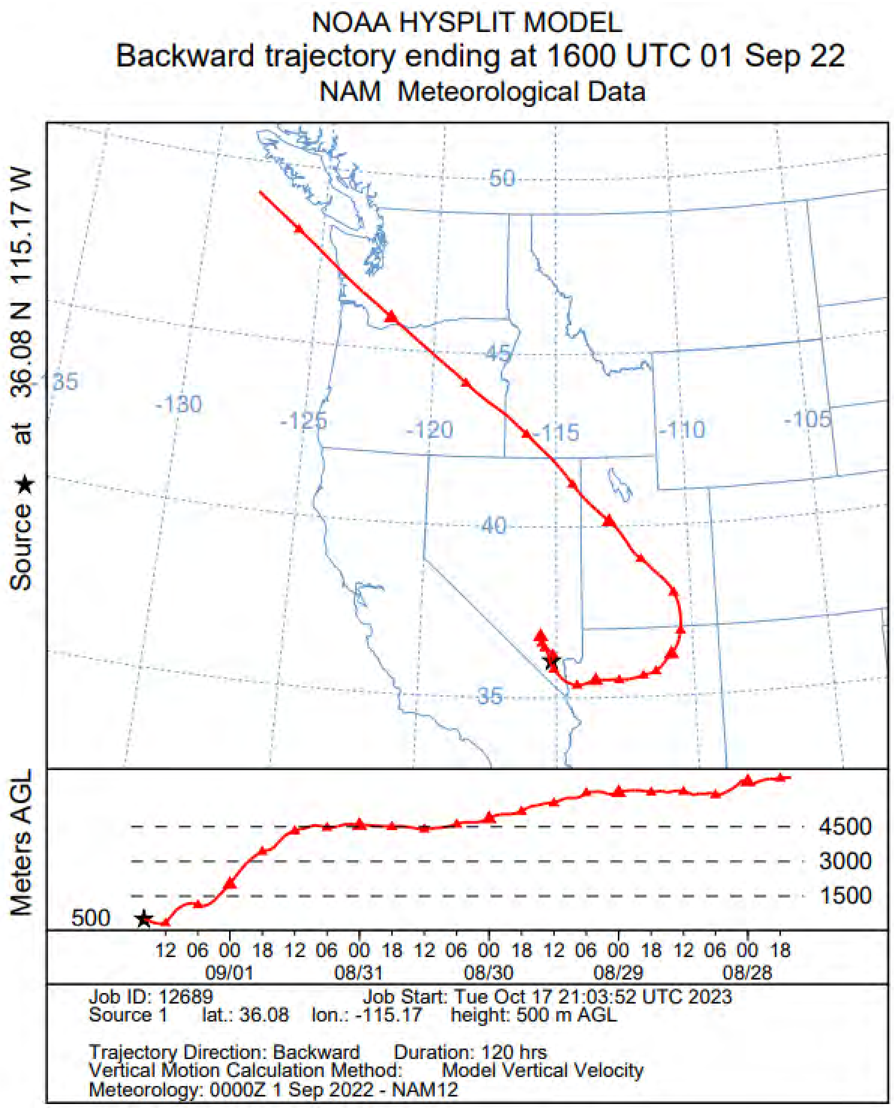

Figure 187. HYSPLIT back trajectory initiated at 16:00 UTC (08:00 PST) on September 1, 2022, using NAM 12 km meteorology. The back trajectory ran for 120 hours ending in Las Vegas (36.08, -115.17) at 500 m agl.

The HYSPLIT dispersion and back trajectory modeling shows transport through the regional smoke plume and into Clark County on the exclusion dates. The dispersion modeling does not specifically show smoke in the Clark County area but does confirm the general pattern of smoke movement and mixing. The back trajectory modeling does show advection of air from the regional smoke plume in the southern Idaho area into Clark County at the beginning of the exclusion dates. The HRRR smoke product forecast (Figure 188) agrees with the HYSPLIT dispersion and back trajectory analysis, showing low levels of vertically integrated smoke over the Clark County region on September 1-2, 2022. The combination of the HMS maps, meteorological information, PBL analysis, HYSPLIT analysis, and HRRR data suggests that regional smoke likely merged from fires throughout the western U.S., transported through a high-pressure system into the southwest U.S., and descended into the well-mixed boundary layer in Las Vegas Valley on September 1-2, 2022.

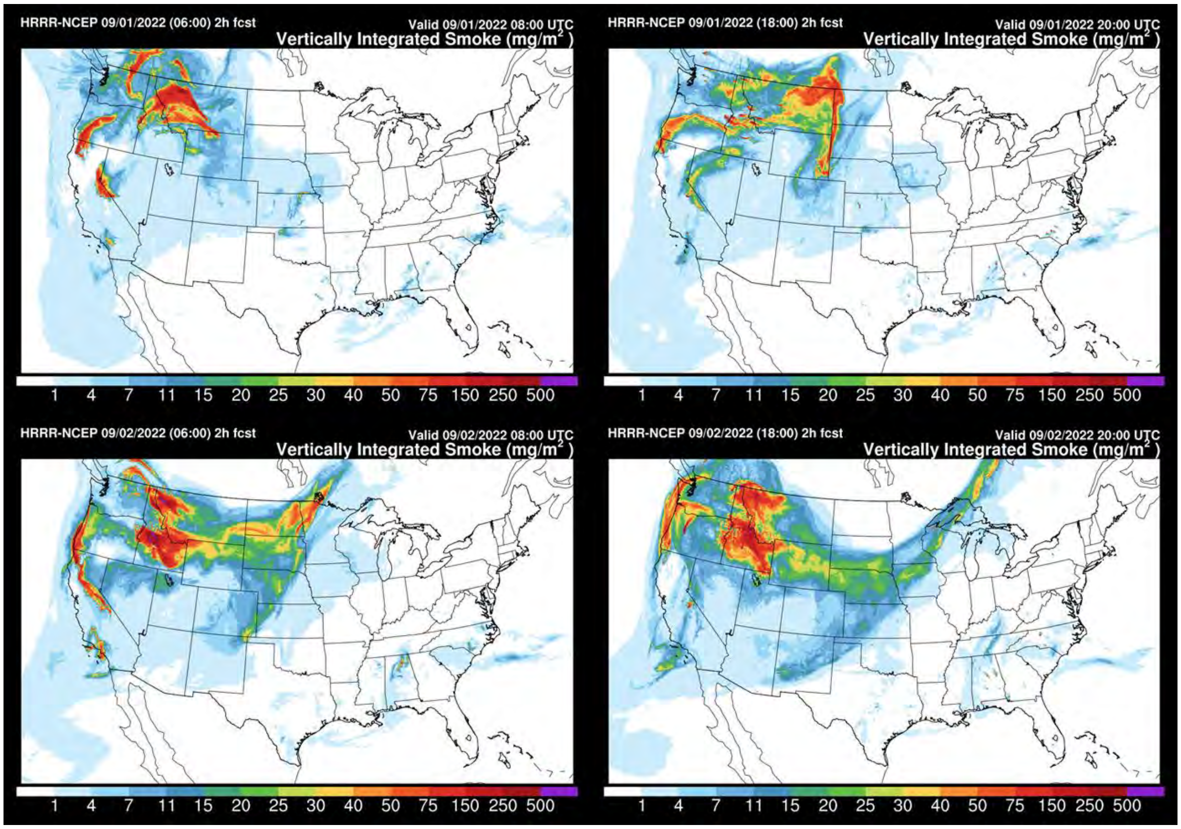

Figure 188. HRRR vertically integrated smoke forecast for September 1-2, 2022, at 00:00 PST and 12:00 PST.

5.4.4 Impacts at the Surface

Figure 189 compares visibility conditions in the Las Vegas Valley before and during the exclusion event, showing visibility conditions at 12:00 on August 31, 2022 (the day before the event), and the event dates of September 1 and 2. The presence of regional wildfire smoke on the exclusion dates from fires identified in Section 5.4.2 may be indicated by some reduction in visibility conditions on September 1 and 2. The mountains in the north and northwestern views are somewhat obscured as the exclusion event continues, which may indicate the presence of increasing regional smoke on the exclusion event days in Clark County.

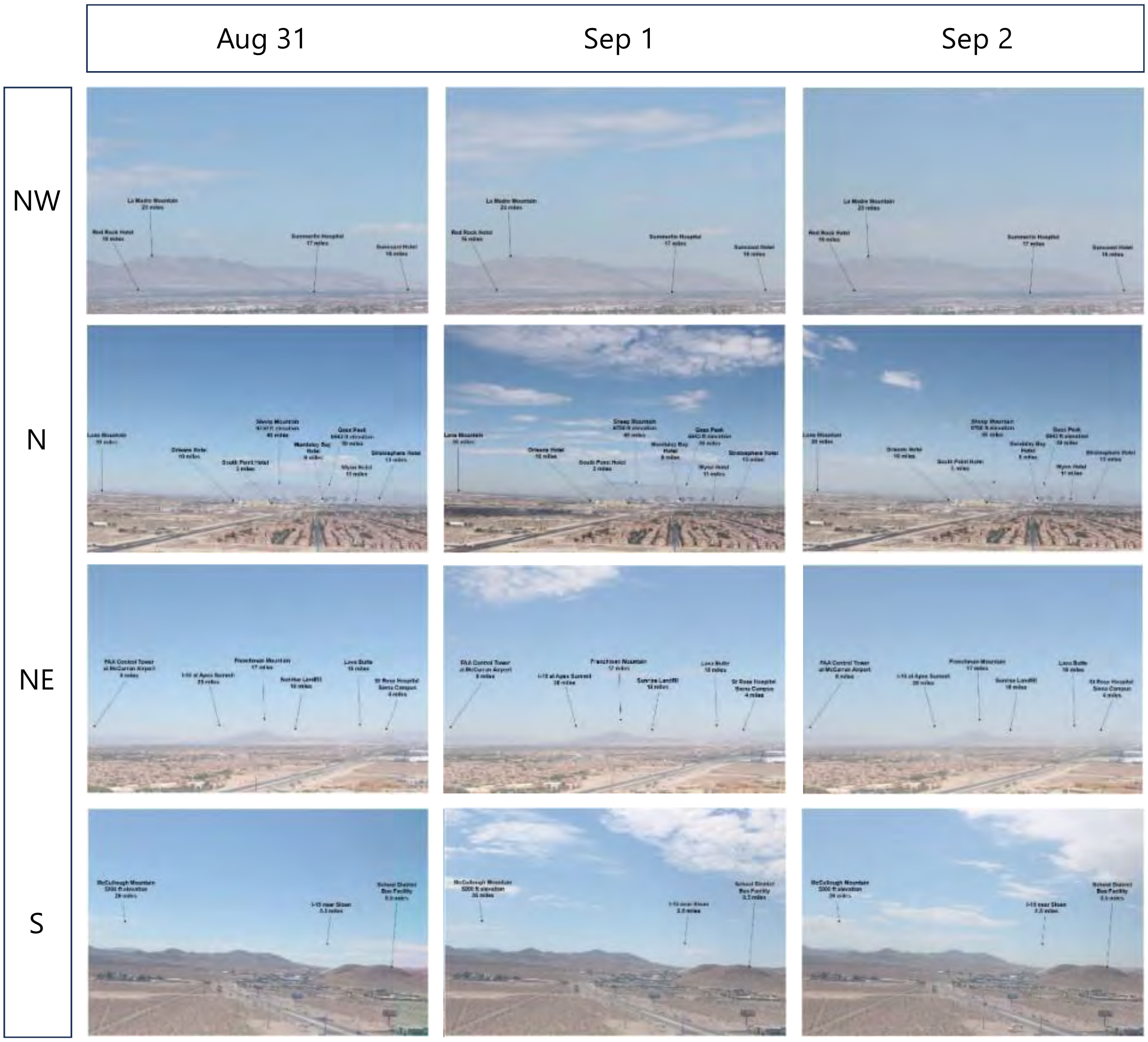

Figure 189. Camera images for August 31, 2022 (left column), September 1 (middle column), and September 2 (right column), taken at 12:00 PST on each day from the M Resort Hotel in Las Vegas. These images face northwest (top row), north (second row), northeast (third row), and south (bottom row).

Figure 190 show the hourly $PM_{2.5}$ concentrations during the event period, compared to the diurnal 10th-90th percentile $PM_{2.5}$ concentration (calculated from May-October 2017-2022), at the Paul Meyer site and all other regional supporting sites that measure $PM_{2.5}$ concentrations. Hourly $PM_{2.5}$ concentrations shown in Figure 190 for the exclusion period met or exceeded the diurnal 90th percentile $PM_{2.5}$ concentrations at multiple sites in the Las Vegas Valley on September 1 and 2. However, none of the spikes in $PM_{2.5}$ concentrations are particularly enhanced or coincide with multiple other sites to indicate an injection of a large amount of smoke. Concentrations do trend upward between September 1 and 2, consistent with the somewhat decreased visibility in the camera images shown in Figure 189.

Figure 191 shows the hourly CO concentrations alongside the 10th-90th percentile diurnal concentrations, calculated from May-October 2017-2022, recorded at the sites that measure CO concentrations. There was an uptick in CO concentrations early on September 1, and concentrations exceeded the 90th percentile at each site at some point during the event period. There were no large enhancements of NO_2 concentrations during the event period. This is consistent with both the light layer of smoke, as modeled via HYSPLIT and HRRR, and long-range transport.

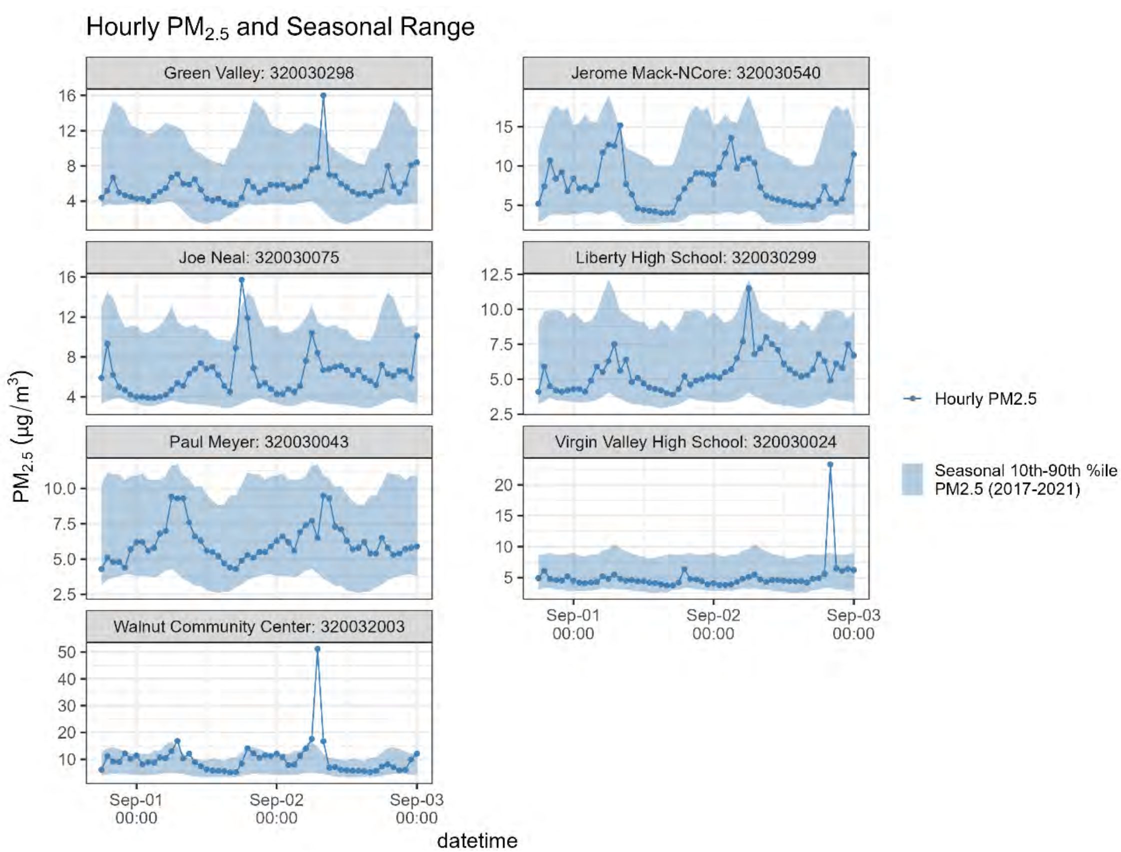

Figure 190. Hourly $PM_{2.5}$ measurements overlaid on the 10th-90th percentile diurnal concentrations recorded at the event-affected measurement sites and supporting sites that measure $PM_{2.5}$ concentrations. The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2022.

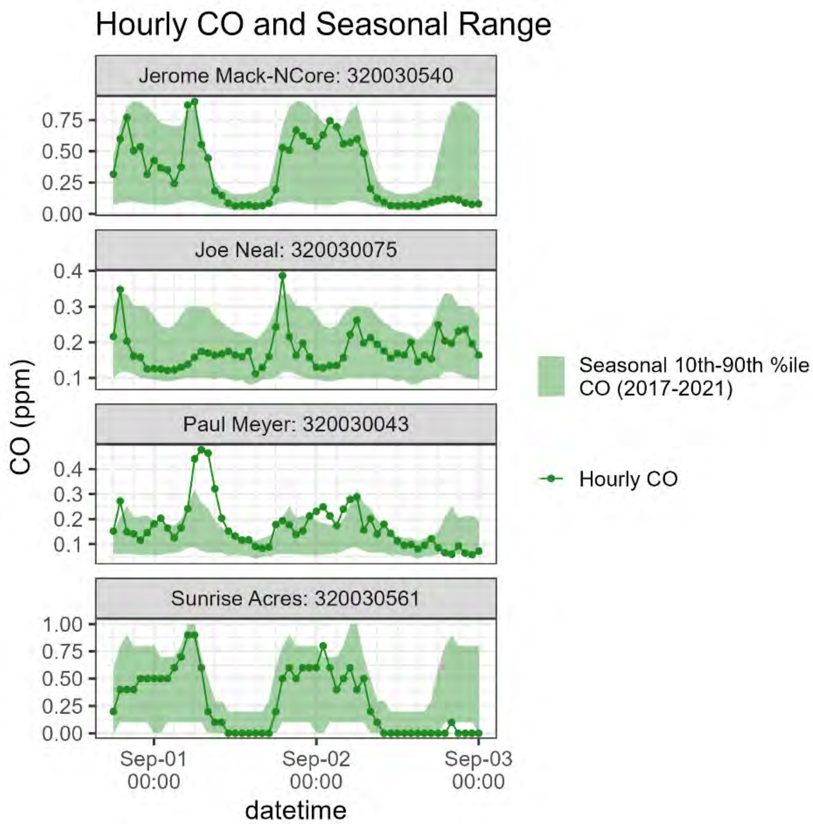

Figure 191. Hourly CO measurements overlaid on the 10th-90th percentile diurnal concentrations at each event-affected measurement site and supporting sites that measure CO concentrations. The 10th-90th percentile concentration is calculated across the ozone production season (May-October) of 2017-2022.

5.4.5 Event Statistics

Table 39 summarizes the daily measurements of ozone, $PM_{2.5}$, CO, and NO_2 concentrations on the exclusion event days of September 1-2, 2022, as well as the percentile rank of the observations compared to the previous five years of ozone season data (May 1-October 31 of 2018-2022). On both September 1 and 2, ozone MDA8 measurements were above the 97th percentile at the Paul Meyer monitoring site. 24-hr average $PM_{2.5}$ concentrations ranged from the 58th - 63rd percentile. CO 1-hr daily maximum concentrations were above the 99th percentile on September 1 and in the 77th percentile on September 2. NO_2 1-hr daily maximum measurements (shown for the Jerome Mack-NCore site, because NO_2 measurements are not collected at the Paul Meyer site) were in the 87th percentile on September 1 and in the 71st percentile on September 2.

Table 39. Percentile of pollutant measurements on the September 1-2, 2022, exclusion days compared with most recent five years of pollutant concentration data (2018-2022).* The percentile rank is calculated across the ozone production season (May 1-October 31) of 2018-2022. Data from the Jerome Mack-NCore site (grey *italicized*) is included for regional NO_2 information because NO_2 measurements are not collected at the Paul Meyer site.

Date	Site Name	Site Code	Ozone		$PM_{2.5}$		CO		NO_2	
			Ozone MDA8 (ppb)	Percent Rank	$PM_{2.5}$ 24-hr Avg (µg/m^3)	Percent Rank	CO 1-hr Daily Max (ppb)	Percent Rank	NO_2 1-hr Daily Max (ppb)	Percent Rank
9/1/2022	Paul Meyer	320030043	74	97.6	6.1	58.7	477	99.3*	--	--
9/1/2022	*Jerome Mack-NCore*	*320030540*	*53*	*49.4*	*7.5*	*58.3*	*898*	*79.8**	*42.8*	*87*
9/2/2022	Paul Meyer	320030043	73	97	6.4	63.5	288	77.1*	--	--
9/2/2022	*Jerome Mack-NCore*	*320030540*	*54*	*53.8*	*7.4*	*56.7*	*744*	*70**	*37.7*	*71.6*

*Sites that have less than five years of data available for a given parameter.

5.5 Request for Exclusion

The wildfire smoke events resulted in ozone measurements that are atypical, extreme, and nonrepresentative of past and future days for Clark County, NV. Appendix W to Part 51 states "control agencies have long expressed a need for consistency in the application of air quality models for regulatory purposes…the expanded requirements for models to cover even more complex problems have emphasized the need for period review and update of guidance on these techniques". Wildfire smoke events are one such complex problem, as wildfire season has extended and encompasses the summer months, also considered to be ozone production season. Wildfire occurrence is wildly considered to be a stochastic natural phenomenon and is therefore inconsistent year-to-year. Downstream smoke impacts, including ozone formation, are not typical nor representative of the ambient conditions of Clark County, Nevada. The four wildfire smoke events identified in this report are inconsistent with previous records and determined to be extreme, as indicated by:

- All site exceedances are above the 95th percentile of all ozone measurements.
- Multiple sites were affected during each event, including those that did not exceed regulatory standards.
- Significant smoke was identified from regional wildfire incidents.

Table 40 provides the evidence and exclusion narrative for each date.

Table 40. Evidence provided for each exclusion date.

Exclusion Date(s)	Event Summary
June 16, 2022	Regional transport of smoke from large wildfires in Arizona, New Mexico, and Baja Mexico in the afternoon of June 16 enhanced ozone concentrations outside of the typical diurnal profile, keeping ozone values high and affecting the maximum daily 8-hr average (MDA8) ozone concentrations at two sites. Smoke maps from the National Oceanic and Atmospheric Administration (NOAA)'s Hazard Mapping System (HMS)., dispersion modeling, Hybrid Single-Particle Lagrangian Integrated Trajectory (HYSPLIT) trajectories, and pollutant concentrations suggest that smoke entered the area in the afternoon on June 16, affecting the typical diurnal profiles of ozone and other pollutants. HMS smoke maps and trajectories confirm a regional smoke plume drifted westward from June 16 to June 17 until it fully encompassed the Las Vegas area. Statistics show ozone concentrations were atypical during this event.

Exclusion Date(s)	Event Summary
July 17, 2022	Regional transport of smoke from large wildfires in Canada mixed with smoke from wildfires in Nevada and California to enhanced ozone concentrations in the Las Vegas Valley on the exclusion day. HMS smoke maps, meteorological information, planetary boundary layer (PBL) analysis, HYSPLIT back trajectories, and High-Resolution Rapid Refresh (HRRR) data suggest that regional smoke was transported around a high-pressure system in the southwest U.S. and descended into the well-mixed boundary layer in the Las Vegas Valley on July 17. Statistics show ozone concentrations were atypical during this event.
July 28-29, 2022	Smoke from two fires in Idaho and California combined to create a light layer of regional smoke in the southwestern U.S. and impacted Clark County on July 28-29. HMS smoke maps, PBL analysis, HYSPLIT back trajectories, meteorological data, and HRRR data suggest that this regional smoke was transported and descended into the well-mixed boundary layer the Las Vegas Valley on July 28. Stagnant conditions on July 29 allowed smoke to linger. Statistics show ozone concentrations were atypical during this event.
September 1-2, 2022	Regional transport of smoke from large fires throughout the western U.S. was carried along a high-pressure system and descended into the well-mixed boundary layer within Clark County on September 1 and 2, which caused increasingly hazy and smoky conditions over the course of the exclusion days. HMS smoke maps, PBL analysis, HYSPLIT back trajectories, meteorological data, and HRRR data suggest that this light regional smoke was transported and descended into the Las Vegas Valley on September 1-2. Statistics show ozone concentrations were atypical during this event at the site most affected by the light regional smoke.

Based on the evidence provided, we formally request exclusion of the following dates in base and projected ozone design values.

ATTACHMENT J:

Enhanced Vapor Recovery Report

Clark County Nonattainment Area
Local Control Measure: Enhanced Vapor Recovery

This document describes a potential emissions reduction strategy and includes emissions reductions estimates associated with Stage I (also referred to as Phase I) vapor recovery (EVR) at gasoline dispensing facilities (GDF) in the Clark County nonattainment area (CCNAA). Stage I refers to emissions that occur when gasoline storage tanks (typically underground storage tanks (USTs)) are filled by tanker trucks. The California Air Resources Board has developed the most stringent additional emissions controls (referred to as enhanced vapor recovery; EVR) which require 98.0% control of Stage I emissions. Estimated emissions reductions and costs for this emissions control measure are shown in Table 1.

Table 1. Stage I vapor recovery control measure summary.[a]

2023 Applicable Emissions Estimates	
NOx:	-
VOC:	4.65 tons/day[b]
Control Measure Summary	
NOx Reduction:	-
VOC Reduction:	3.72 tons/day
Cost-effectiveness:	*$2,048 - $10,494/ton VOC*

[a] "-" indicate zero Nitrogen Oxides (NOx) emissions in the inventory and thus no emissions reductions.
[b] Calendar Year 2026 July average weekday inventory. Source: EPA 2016v3 modeling platform. Available at https://www.epa.gov/air-emissions-modeling/2016v3-platform, accessed in April 2024. The NAA is a subarea of Clark County; NAA specific emissions were estimated by allocating 2016v3 county-level emissions with 2016v3 spatial surrogates.

Applicable Source(s) Description

Figure 1 shows a visual depiction of a GDF with Stage I (or Phase I) and Stage II (or Phase II)

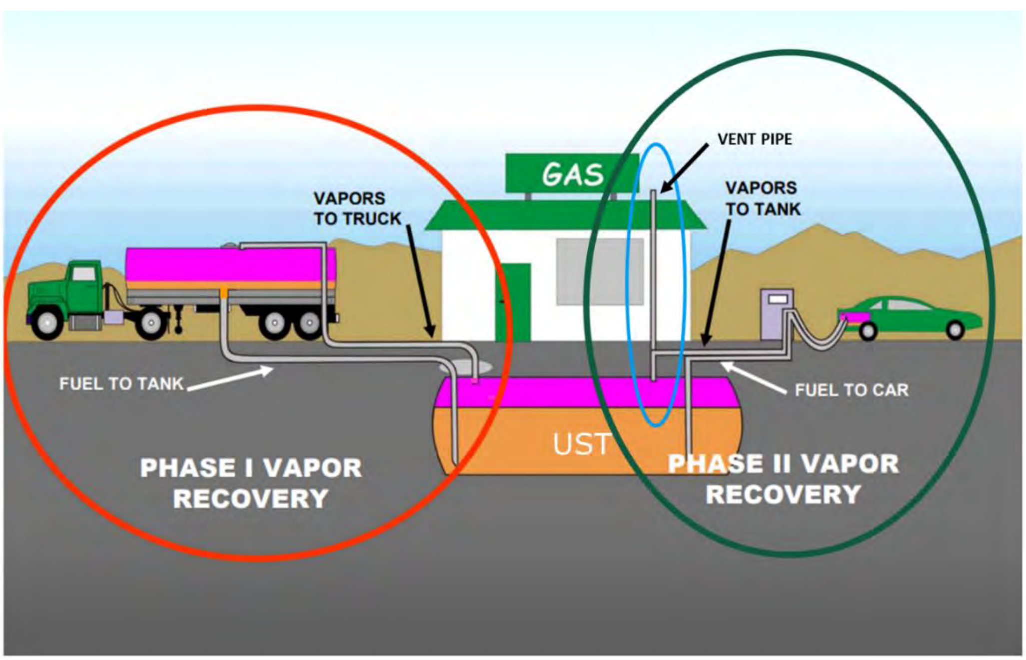

Figure 1. Stage I and Stage II breathing emissions sources at a GDF (adapted from Heiss, 2008).

Stage I (or Phase I) refers to the emissions source category associated with the transfer of gasoline from tanker trucks to USTs. As the UST is filled with gasoline, gasoline vapors in the UST are displaced to the atmosphere or routed back to the tanker truck.

Clark County permitting requirements for GDFs currently require Stage I vapor recovery for stations with a maximum gasoline throughput of 100,000 gallons per month or more per 40 CFR, Subpart CCCCCC (1.2 million gallons per year). GDFs with a maximum gasoline throughput less than the federal threshold are not required to have Stage I vapor recovery control equipment. Per Clark County GDF permit requirements, all vapor recovery systems are required to have an efficiency rating of at least 90% or 95.0% control efficiency which is certified by an "industry-recognized certification body" such as the CARB. Due to the now-repealed Air Quality Rule (AQR) 52, and its prior State Implementation Plan (SIP)-approved versions, most of the gasoline station tanks in the CCNAA are equipped with Stage I controls.

Stage II (or Phase II) refers to the emissions source category associated with the transfer of gasoline from the UST to a vehicle's gas tank. As the vehicle's gas tank is filled with gasoline, gasoline vapors in the vehicle's tank may be displaced to the atmosphere or controlled. Stage II also includes emissions from spillage from gasoline nozzle drip and overflows from the vehicle's fuel tank fill pipe. Clean Air Act Amendments require the use of on-board refueling vapor recovery (ORVR) canisters to capture vapors from vehicle gasoline tanks to release back into the vehicle's engines for vehicles manufactured after 2006. Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ) is not considering Stage II emissions controls as an emissions control measure for the ROP demonstration.Table 2 lists the source classification codes (SCCs), associated category descriptions, and 2026 Stage I VOC emissions from in the CCNAA (Ramboll, 2024).

Table 2. Applicable SCCs.

Desc. One	Desc. Two	Desc. Three	Desc. Four	SCC	2026 VOC Emissions (tons/day)
Storage and Transportation	Petroleum and Petroleum Product Storage	Gasoline Service Stations	Stage I: Submerged Filling	2501060051	4.47
			Stage I: Splash Filling	2501060052	-
			Stage I: Balanced Submerged Filling	2501060053	0.17
				Total	4.65

Control Measure Description

Stage I vapor recovery was established by EPA in 1975 to control emissions at GDFs when gasoline is transferred from tanker trucks to USTs. During tank filling, submerged pipes are used to minimize VOC and hazardous air pollutant (HAP) emissions that result from the displacement of gasoline vapors in the UST by the gasoline being loaded into the UST (Oregon Department of Environmental Quality, 2022). A vapor balancing system was introduced by some states and local agencies to recover the displaced gasoline vapors by routing them back to tanker trucks. CARB adopted Stage I EVR regulations in 2000 (CARB, 2020). Under this measure, GDFs in Clark County would be required to meet CARB Module 1 Phase I Vapor Recovery requirements that mandate Stage I EVR with 98.0% control efficiency.

Emissions Reductions

The 2026 CCNAA emissions inventory is taken from the 2016v3 modeling platform[1]. The 2016v3 modeling platform 2026 Stage I emissions were forecast from 2016 base year emissions assuming no change to underlying emissions factors. 2016v3 base year Stage I emissions were forecast from the 2014 National Emissions Inventory (EPA, 2022)[2], similarly, without change to underlying emissions factors, assuming 90% control of Stage I emissions. Based on compliance with CARB's 98% enhanced vapor recovery requirement, emissions reductions of 80% were estimated. The 80% emissions reduction assumes universal application of CARB Stage I enhanced vapor recovery requirements across the CCNAA after rule adoption. If smaller throughput GDFs are exempt from the Stage I enhanced vapor recovery requirement, emissions reductions would be less.

VOC emissions reductions from Stage I EVR at GDFs are presented in Table 3.

Table 3. Estimated potential future year VOC emissions reductions from gasoline service stations.

Desc. One	Desc. Two	Desc. Three	Desc. Four	SCC	VOC Emissions reduction (tons/day)	Percent Reduction
Storage and Transportation	Petroleum and Petroleum Product Storage	Gasoline Service Stations	Stage 1: Submerged Filling	2501060051	3.58	80%
			Stage 1: Splash Filling	2501060052	-	-
			Stage 1: Balanced Submerged Filling	2501060053	0.14	80%
					3.72	80%

Cost-effectiveness

ERG (2012) estimated cost per ton of VOC reduced by gasoline facility throughput from application of CARB's Stage I EVR systems in Massachusetts (see Table 4). Cost per ton of emission reduction decreases as GDF gasoline throughput increases. The largest facilities, with gasoline throughput greater than 2 million gallons per year, show a financial benefit based on substantial estimated fuel savings from this measure. ERG (2012) notes that the cost per ton can be decreased by allowing GDFs to make Stage I EVR modifications gradually rather than at a fixed time. Cost-effectiveness of application of the CARB compliant Stage I EVR in Clark County will depend upon GDF throughput, whether there is a low gasoline throughput exemption, and the extent to which any existing control equipment is already in compliance.

[1] https://www.epa.gov/air-emissions-modeling/2016v3-platform. Accessed online in April 2024.

[2] EPA, 2022. 2014v2 National Emissions Inventory Supporting Data for Gasoline Distribution. https://gaftp.epa.gov/air/nei/2014/doc/2014v2_supportingdata/nonpoint/Stage%20I%20Gasoline%20Distribution%20for%20NEI%20v2.zip, Accessed online in October 2022.

Table 4. Stage I enhanced vapor recovery system cost effectiveness (source: ERG, 2012)

Gasoline Throughput (gallons/year)	Cost-Effectiveness ($/ton VOC)
<120,000	$55,005
120,000 to 240,000	$17,029
240,001 to 500,000	$7,327
500,001 to 1,000,000	$2,992
1,000,001 to 2,000,000	$885
>2,000,000	-$253
Total	$2,048

Geographic Applicability

A control measure for Stage I EVR is assumed to be applied throughout CCNAA area to mitigate VOC emissions.

Responsible Agency

The Clark County Division of Air Quality is responsible for enforcing SIP-approved control measures and other air permitting rules. The current Clark County requirements for GDFs are defined under Clark County's General Permit to Construct and/or Operate Gasoline Dispensing Operations (DAQ, 2020).

Implementation Schedule

A phased approach to implementation will allow continued operation of equipment not compliant with CARB EVR requirements for several years based on gradual replacement of existing equipment with EVR-compliant equipment.

Implementation Feasibility

Clark County general permit requirements stipulate the use of a Stage I vapor recovery system at GDFs; albeit with a lower control efficiency requirement than CARB EVR requirements. CARB's Stage I enhanced vapor recovery requirements have been implemented in several states, including Massachusetts and Connecticut.

Public Acceptance

VOC emissions from refueling can cause or contribute to ozone levels that violate NAAQS for ozone. GDF owners and operators may have a negative perception of these requirements because of the costs required to upgrade Stage I control systems.

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Ramboll 2024. "2017 and 2026 Emission Inventories for the 15% Rate of Progress (ROP) Plan for the Clark County Ozone Nonattainment Area". Prepared for the Clark County Division of Air Quality. April.

ATTACHMENT K:

Documentation of Public Review Process

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1.0 30-DAY PUBLIC COMMENT PERIOD

1.1 NOTICE OF PUBLIC COMMENT AND PUBLIC HEARING

NOTICE OF PUBLIC COMMENT PERIOD AND PUBLIC HEARING ON THE PROPOSED 2015 OZONE NAAQS ATTAINMENT PLAN FOR THE LAS VEGAS VALLEY MODERATE NONATTAINMENT AREA

NOTICE IS HEREBY GIVEN of a public comment period and public hearing on the proposed *2015 Ozone NAAQS Attainment Plan for the Las Vegas Valley Moderate Nonattainment Area: Clark County, NV*. The U.S. Environmental Protection Agency (EPA) designated the Las Vegas Valley as a marginal nonattainment area for the 2015 ozone National Ambient Air Quality Standard (NAAQS), effective August 3, 2018. On January 5, 2023, EPA determined that the area failed to attain the 2015 ozone NAAQS by the applicable marginal nonattainment date and reclassified the Las Vegas Valley (Hydrographic Area 212) as a moderate nonattainment area. Under Sections 172 and 182(b) of the Clean Air Act, Clark County is required to submit a state implementation plan (SIP) that meets the following planning requirements for the Las Vegas Valley moderate nonattainment area: emission inventories, attainment demonstration, nonattainment new source review, 15% rate of progress, reasonably available control measures, reasonably available control technology, motor vehicle inspection and maintenance, contingency measures, and a motor vehicle emissions budget for transportation conformity. This plan satisfies those requirements. If adopted, the plan will be submitted to the state of Nevada and EPA as a revision to the Nevada SIP.

NOTICE IS FURTHER GIVEN that a 30-day public comment period will begin on August 15, 2024, and end at 12:00 PM on September 16, 2024. The public may review and provide written comments on the proposed plan during this period. The Board of County Commissioners will consider the proposed plan, along with all written and any oral public comments, at a public hearing at 10:00 AM on November 5, 2024, in the Commission Chambers, Clark County Government Center, 500 S. Grand Central Parkway, Las Vegas, NV.

A copy of the proposed plan is available for review on the Department of Environment and Sustainability website at:
https://www.clarkcountynv.gov/government/departments/environment_and_sustainability/public_communications/public_notices.php

The department must receive any written comments at 4701 W. Russell Road, Suite 200, Las Vegas, Nevada 89118, by 12:00 PM on September 16, 2024. Comments should be addressed to Air Quality Planning Section at the same mailing address, emailed to aqplanning@clarkcountynv.gov, or faxed to (702) 383-9994.

Published: August 15, 2024

Ted Lendis, Planning Manager

1.2 DES WEBSITE NOTICES

Translate

air quality Proposed Revision to Nevada SIP

division of air quality

Posted Thursday, August 15, 2024

NOTICE OF PUBLIC COMMENT PERIOD AND PUBLIC HEARING ON THE

PROPOSED 2015 OZONE NAAQS ATTAINMENT PLAN FOR

THE LAS VEGAS VALLEY MODERATE NONATTAINMENT AREA

DAQ welcomes comments on the proposed *2015 Ozone NAAQS Attainment Plan for the Las Vegas Valley Moderate Nonattainment Area: Clark County, NV.* Under Sections 172 and 182(b) of the Clean Air Act, Clark County is required to submit a state implementation plan (SIP) that meets the following planning requirements for moderate nonattainment areas: emission inventories, attainment demonstration, nonattainment new source review, 15% rate of progress, reasonably available control measures, reasonably available control technology, motor vehicle inspection and maintenance, contingency measures, and a motor vehicle emissions budget for transportation conformity . This plan is intended to satisfy the planning requirements for the Las Vegas Valley moderate nonattainment area. If adopted, the plan will be submitted to the state of Nevada and EPA as a revision to the Nevada SIP.

The Board of County Commissioners will consider the proposed plan, along with all written and any oral public comments, at a public hearing at 10:00 AM on November 5, 2024, in the Commission Chambers, Clark County Government Center, 500 S. Grand Central Parkway, Las Vegas, NV.

Deadline for comment submission is 12 p.m. PDT, Monday, September 16, 2024.

Documents

- 20240815 CCDES 2015 O3 Moderate Attainment Plan Notice of Public Comment Hearing.pdf
- 20240815 CCDES 2015 O3 Moderate Attainment Plan_draft.pdf
- AttA_20231130 CCDES 2015 O3 Moderate Attainment SIP 2017 and 2023 EI.pdf
- AttB_20240628 CCDES 2015 O3 Moderate Attainment SIP Attainment Demo TSD.pdf
- AttC_20240620 CCDES CTG RACT Analysis_Final draft.pdf
- AttD_20231013 CCDES Major Source RACT Analysis_Final draft.pdf
- AttE_20240619 RACM Analysis_Final draft.pdf
- AttF_20240405 CCDES 2015 O3 Moderate Attainment SIP 2017 and 2026 ROP EI.pdf
- AttG_20240624 CCDES 2015 O3 Moderate Attainment SIP 15 ROP Plan TSD.pdf
- AttH_Evaluation of Effectiveness of IM Program.pdf
- AttI_202311 STI Wildfire Atypical O3 Event Analysis TSDs 2016-2022.pdf
- AttJ_20240628 Enhanced Vapor Recovery Report.pdf

Please provide your contact information so we may reach you in response to your comments.

1.2.1 Declaration of DES Website Posting

DECLARATION OF WEBSITE POSTING OF PUBLIC NOTICE

STATE OF NEVADA)
) ss.
COUNTY OF CLARK)

I, Araceli Pruett, declare that I am over 18 years of age and a Senior Planner with the Clark County Department of Environment and Sustainability (DES). I declare that the *2015 Ozone NAAQS Attainment Plan for the Las Vegas Valley Moderate Nonattainment Area: Clark County, NV* was posted on the DES website from August 15 through September 16, 2024. Below is a screenshot of the website posting:
https://www.clarkcountynv.gov/government/departments/environment_and_sustainability/public_communications/public_notices.php


Proposed Revision to Nevada SIP

air quality

Posted Thursday, August 15, 2024

NOTICE OF PUBLIC COMMENT PERIOD AND PUBLIC HEARING ON THE PROPOSED 2015 OZONE NAAQS ATTAINMENT PLAN FOR THE LAS VEGAS VALLEY MODERATE NONATTAINMENT AREA

DAQ welcomes comments on the proposed *2015 Ozone NAAQS Attainment Plan for the Las Vegas Valley Moderate Nonattainment Area: Clark County, NV*. Under Sections 172 and 182(b) of the Clean Air Act, Clark County is required to submit a state implementation plan (SIP) that meets the following planning requirements for moderate nonattainment areas: emission inventories, attainment demonstration, nonattainment new source review, 15% rate of progress, reasonably available control measures, reasonably available control technology, motor vehicle inspection and maintenance, contingency measures, and a motor vehicle emissions budget for transportation conformity. This plan is intended to satisfy the planning requirements for the Las Vegas Valley moderate nonattainment area. If adopted, the plan will be submitted to the State of Nevada and EPA as a revision to the Nevada SIP.

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Deadline for comment submission is 12 p.m. PDT, Monday, September 16, 2024.

I declare that the foregoing is true and correct and that this declaration was executed in Las Vegas, NV, on September 17, 2024.

Araceli Pruett

Araceli Pruett
DES Senior Planner

1.3 DES FACEBOOK POSTING

Clark County Department of Environment & Sustainability
August 16 at 11:45 AM ·

"Say...what's the Division of Air Quality doing about ozone in Clark County, Nevada?" Great question. We have a 1,761-page #VegasAirQuality ozone attainment plan available for review and public comment through Sept. 16.

Review the document & leave comments ▶ bit.ly/planningpubnotice.

1.4 DES X POSTING

Clark County Dept. of Environment & Susta @ClarkCounty · Aug 15

"Say...what's the Division of Air Quality doing about ozone in @ClarkCountyNV?" Great question. We have a 1,761-page #VegasAirQuality ozone attainment plan available for review and public comment through Sept. 16. Review the document & leave comments ▶ bit.ly/planningpubnot....

1.5 E-NOTICE (PUBLIC INPUT)

From: Clark County Dept. of Environment & Sustainability
To: Anabell Pruett
Subject: 30-DAY PUBLIC COMMENT PERIOD AND PUBLIC HEARING ON THE PROPOSED 2015 OZONE NAAQS ATTAINMENT PLAN
Date: Thursday, August 15, 2024 3:26:34 PM

Public Notice:
30-Day Notice of Public Comment Period and Public Hearing on the Proposed 2015 Ozone NAAQS Attainment Plan for the Las Vegas Valley Moderate Nonattainment Area

NOTICE IS HEREBY GIVEN of a public comment period and public hearing on the proposed *2015 Ozone NAAQS Attainment Plan for the Las Vegas Valley Moderate Nonattainment Area: Clark County, NV*. The U.S. Environmental Protection Agency (EPA) designated the Las Vegas Valley as a marginal nonattainment area for the 2015 ozone National Ambient Air Quality Standard (NAAQS), effective August 3, 2018. On January 5, 2023, EPA determined that the area failed to attain the 2015 ozone NAAQS by the applicable marginal nonattainment date and reclassified the Las Vegas Valley (Hydrographic Area 212) as a moderate nonattainment area. Under Sections 172 and 182(b) of the Clean Air Act, Clark County is required to submit a state implementation plan (SIP) that meets the following planning requirements for the Las Vegas Valley moderate nonattainment area: emission inventories, attainment demonstration, nonattainment new source review, 15% rate of progress, reasonably available control measures, reasonably available control technology, motor vehicle inspection and maintenance, contingency measures, and a motor vehicle emissions budget for transportation conformity. This plan satisfies those requirements. If adopted, the plan will be submitted to the state of Nevada and EPA as a revision to the Nevada SIP.

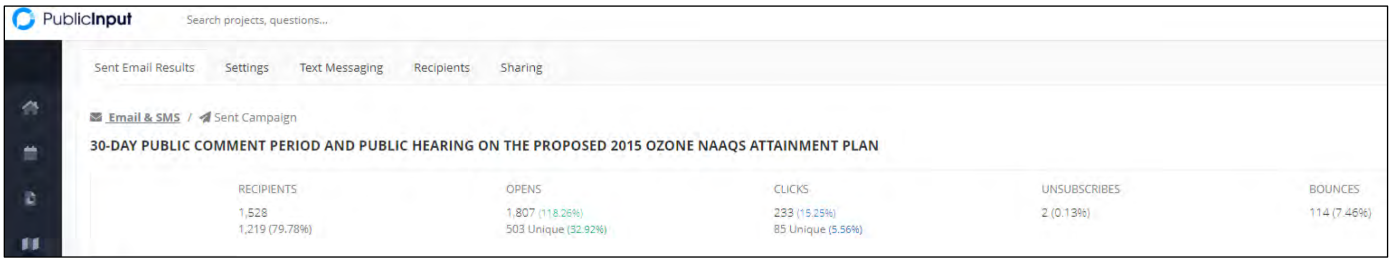
NOTICE IS FURTHER GIVEN that a 30-day public comment period will begin on August 15, 2024, and end at 12:00 PM on September 16, 2024. The public may review and provide written comments on the proposed plan during this period. The Board of County Commissioners will consider the proposed plan, along with all written and any oral public comments, at a public hearing at 10:00 AM on November 5, 2024, in the Commission Chambers, Clark County Government Center, 500 S. Grand Central Parkway, Las Vegas, NV.

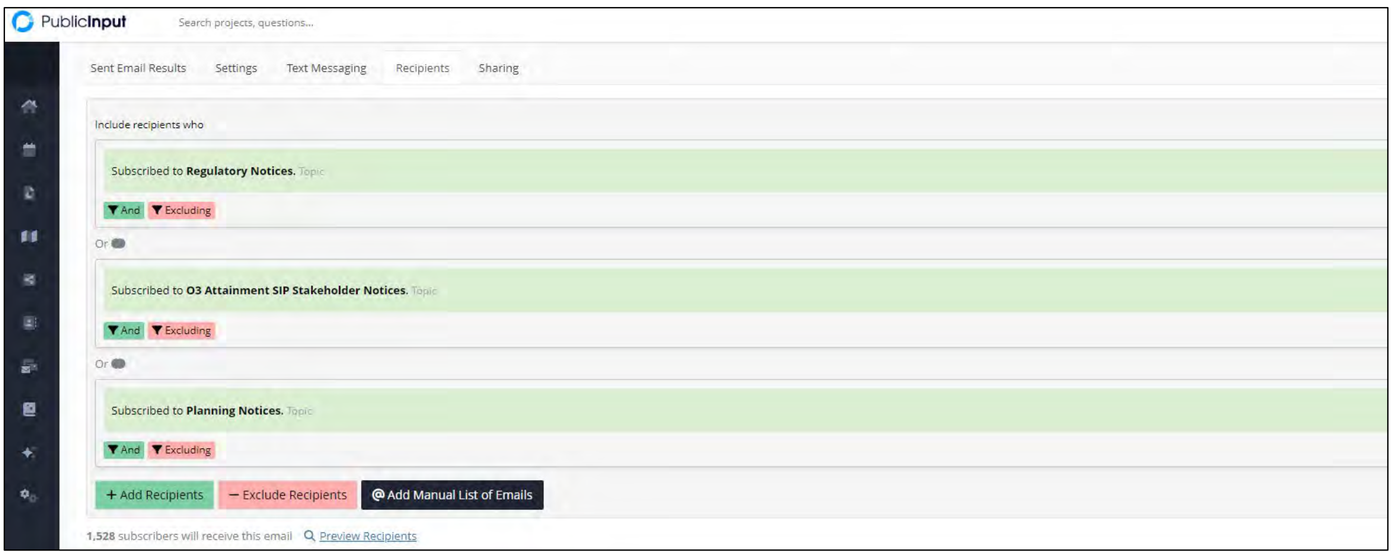
A copy of the proposed plan is available for review on the Department of Environment and Sustainability website at:
https://www.clarkcountynv.gov/government/departments/environment_and_sustainability/public_communications/public_notices.php

The department must receive any written comments at 4701 W. Russell Road, Suite 200, Las Vegas, Nevada 89118, by 12:00 PM on September 16, 2024. Comments should be addressed to Air Quality Planning Section at the same mailing address, emailed to aqplanning@clarkcountynv.gov, or faxed to (702) 383-9994.

1.5.1 E-Notice Distribution

To encourage stakeholder participation on the proposed plan, the public notice was emailed to over 1,500 stakeholders via our Public Input email subscription service. These stakeholders included individuals on our Ozone Attainment SIP, Regulatory, and Planning notices distribution lists. These lists are comprised of permitted sources, local businesses, environmental groups, government agencies, nearby tribal nations, and other interested parties. Stakeholders were invited to review the proposed plan on the department's website and to contact staff by email with questions or comments.





1.6 PUBLIC COMMENT REPORT

Introduction: From August 15, 2024, through September 16, 2024, the Clark County Department of Environment and Sustainability (DES) conducted a public comment period on the proposed *2015 Ozone NAAQS Attainment Plan for the Las Vegas Valley Moderate Nonattainment Area: Clark County, NV.*

This report summarizes and responds to comments received consistent with the State Implementation Plan (SIP) submission requirements of 40 CFR Part 51.103(a) and 40 CFR Part 51, Appendix V, Section 2.1(h). The responses herein follow the federal Administrative Procedure Act requirements to respond to significant comments (Title 5, Section 553(c) of the United States Code), which federal courts have generally found to be those that raise relevant issues with the proposed plan/rules and would warrant changes.

COMMENTOR: Nick Christenson, npc@gangofone.com, received: September 15, 2024

Comment:

Las Vegas is the second fastest warming city in the country and the third sunniest, and this heat and sunlight along with NO_x and volatile organic compounds are the recipe for the unacceptable levels of ground level ozone we experience. We know that, as a species, we are not yet finished pumping CO_2 into the atmosphere, the principal cause of global warming. Consequently, on our present course, our city will continue to heat up. Because of this, even if we were to reduce the production of the other two factors that cause ozone, our ozone levels could continue to rise. If we are serious about reducing ozone levels and all its terrible effects on our community, we can't just reduce our emissions by a little, we have to reduce our emissions by a lot. We're either serious about this, or we're, quite literally, just blowing smoke.

The health effects from ground level ozone are significant. The American Lung Association has repeatedly given the air quality in the Las Vegas Valley an "F" grade[1]. We see this in our rates of asthma as well as other respiratory diseases which lead to bad health outcomes, which just about every new study reveals to be much worse than we previously thought (see [2][3][4] and many, many more). These respiratory ailments also lead to missed work which also has a significant economic impact. Our children are especially vulnerable to air pollution, which not only leads to increased childhood asthma and susceptibility to other illnesses, but leads to reduced school attendance, which contributes to our community-wide educational outcomes being below desired levels.

There's no mystery about what we need to do, and there is no way to make a meaningful impact outside of these measures. If we're serious, these are the things we'll do. If we don't do these things, it means we're simply not serious about addressing our air quality:

- Convert our vehicle fleet, especially our medium and heavy duty vehicles which are disproportionately prone to emit NOx compounds, to zero emission vehicles, either electric or hydrogen powered.

- Reduce the number of vehicle miles traveled for valley residents, both in number of trips and distance per trip. This can be accomplished by improving our mass transit systems and making their use increasingly attractive to residents and visitors, as well as adjusting our land use to increase the density of our community, bringing people and services physically closer to one another. Certainly, continuing our policy of sprawling our urban environment would likely be the singular worst possible thing we could do, both in terms of increasing emissions due to longer commutes and by exacerbating the heat island effect of our community.
- Additionally, we should stop adding and then actively reduce NO_x point sources in the Las Vegas valley. This means not building any more fossil fuel fired power generation facilities within the valley and rapidly converting existing generation to zero-carbon energy facilities. By necessity, these would become distributed solar plus electrical storage facilities, including premises energy storage configured by the electrical utility to "peak shave" in a so-called "virtual power plant" configuration[5]. We will also need to eliminate point source emissions from existing and especially any new industry that wishes to operate in the valley, and we must say, "No," to any new business that would further degrade our air quality.

Expanding upon this, business and government in Clark County is currently set upon a path of expanding both our population and our economic product. This is not completely incompatible with a policy of reducing ground level ozone, but if we are to achieve better air quality during both economic growth and a warming climate, our reduction efforts cannot be half-hearted. We must drastically reduce our air pollution emissions. If we're not willing to make the changes that will lead to drastic reductions in emissions, then let's not pretend we're serious about improving air quality in southern Nevada, because we're not.

We know how to solve our air quality problems. Technical solutions for these issues exist and are eminently feasible. Doing so will improve our health and implementing them will come with net cost savings for our community. However, there exist many powerful entities operating in southern Nevada with an interest in maintaining the status quo and not addressing the factors that are exacerbating our air quality problems. The only question is whether we have the will to stand up to those few who feel they stand to lose by improving everyone else's lives. It really is as simple as that.

DES Response:

The comment provides an overview of ozone formation and its adverse effects on public health. The commentor states that emissions of volatile organic compounds (VOC) and oxide(s) of nitrogen (NO_x) must be reduced significantly and proposes three strategies to make meaningful impacts: implementing zero-emitting vehicles, reducing vehicle miles traveled, and limiting the addition of new stationary sources of NO_x within the Las Vegas Valley. The comments do not specifically identify any part of the proposed SIP that does not meet the requirements of the Clean Air Act and U.S. Environmental Protection Agency (EPA) regulations.

As dispersion and photochemical models indicate, the formation of ozone in the Las Vegas Valley is predominantly caused by emissions transported from outside Clark County (international and regional), including those generated by wildfires, and emissions from motor vehicles that combust fossil fuels. DES's authority to control these sources of ozone is limited; therefore, control measures addressed in the proposed SIP focus strongly on stationary sources. DES is working concurrently with the Regional Transportation Commission of Southern Nevada (RTC) and the All-In Clark County sustainability initiative to address motor vehicle emissions separately.

To address local VOC and NO_x contributions, DES implemented seven new regulations that impose additional controls on new and existing stationary sources for which EPA has published a Control Technique Guideline. Additionally, DES assessed existing equipment at major stationary sources and is implementing another regulation to ensure that adequate levels of emission controls are required as part of this SIP. All these regulations require that emission controls meet Reasonably Available Control Technology standards. DES will incorporate additional emission control requirements into its regulatory framework while continuing efforts to reduce ozone in the Las Vegas Valley.

DES works closely with the RTC to ensure that transportation programs align with air quality standards. This collaboration includes evaluating and monitoring transportation projects to ensure that they do not adversely impact air quality or contribute to nonattainment of the standard.

DES is the lead agency in the All-In Clark County sustainability initiative, which promotes electric vehicle technology and alternative transportation options. This community-wide collaborative effort encourages government agencies, utilities, and private enterprise to replace gas vehicle fleets with alternative-fuel vehicles and technologies. Through these partnerships, DES aims to create a robust infrastructure that supports alternative vehicle adoption.

DES shares the commenter's interest in protecting public health and improving air quality in Clark County. It will continue to work with EPA and other state, local, and federal agencies, as well as private entities, to meet its regulatory obligations. As Clark County continues to face the challenges of growth and increasingly stringent public health standards, DES will pursue attainment of these standards by addressing all sources of NO_x and VOC with open and inclusive governance.

2.0 BOARD OF COUNTY COMMISSIONERS MEETING – 10/15/2024 (SET PUBLIC HEARING)

2.1 AGENDA ITEM

CLARK COUNTY BOARD OF COMMISSIONERS AGENDA ITEM

Petitioner: Marci Henson, Director, Department of Environment and Sustainability

Recommendation:

Set a public hearing on November 5, 2024, at 10:00 a.m. to approve, adopt, and authorize submittal of the "2015 Ozone NAAQS Attainment Plan for the Las Vegas Valley Moderate Nonattainment Area: Clark County, NV" to the State of Nevada for submission to the U.S. Environmental Protection Agency for review and approval as a revision to the Nevada State Implementation Plan. (For possible action)

FISCAL IMPACT:

Fund #:	N/A	Fund Name:	N/A
Fund Center:	N/A	Funded PGM/Grant:	N/A
Amount:	N/A		
Description:	N/A		
Additional Comments:	N/A		

BACKGROUND:

On October 1, 2015, the U.S. Environmental Protection Agency (EPA) revised the 8-hour ozone National Ambient Air Quality Standard (NAAQS), lowering both the primary and secondary standards from 0.075 to 0.070 parts per million. The Las Vegas Valley (Hydrographic Area 212) was designated as a marginal nonattainment area for the 2015 ozone standard, effective August 3, 2018. On January 5, 2023, EPA determined that the area failed to attain the 2015 ozone NAAQS by the applicable marginal nonattainment date and reclassified the Las Vegas Valley as a moderate nonattainment area. The reclassification notice established a submission deadline of January 1, 2023, for the area's moderate attainment plan. On October 18, 2023, EPA issued a finding of failure to submit a moderate attainment plan for the Las Vegas Valley nonattainment area by the submission deadline.

Under Sections 172 and 182(b) of the Clean Air Act, Clark County is required to submit a state implementation plan (SIP) that meets the following planning requirements for moderate nonattainment areas: emission inventories, attainment demonstration, nonattainment new source review, 15% rate of progress, reasonably available control measures, reasonably available control technology, motor vehicle inspection and maintenance, contingency measures, and a motor vehicle emissions budget for transportation conformity. The attached plan is intended to satisfy the EPA's requirements for moderate nonattainment areas and resolve its finding of failure to submit. The plan and all attachments may be reviewed at the following link: https://publicinput.com/e58566.

The plan was made available for public comment from August 15 through September 16, 2024. One comment was received. Attachment K documents the public review process. Information not yet included in Attachment K will be added after the public hearing and upon Board approval of this plan.

A public hearing on November 5, 2024, will provide the public with an additional opportunity to provide comments prior to the Board of County Commissioners' consideration of the plan.

Cleared for Agenda
10/15/2024
File ID#
24-1353

2.2 MEETING SUMMARY

18. Approve and authorize the submission of a grant application to the U.S. Department of Housing and Urban Development (HUD) for the Northern Nevada Continuum of Care (CoC) Homeless Management Information System (HMIS) Project, by Clark County Social Service (CCSS), in the amount of $122,822 and $30,706 in Emergency Solutions Grant (ESG) cash match from Nevada Housing Division to provide software and administration; and authorize the Deputy County Manager, or her designee, to accept any grant funds awarded. (For possible action)

ACTION: APPROVED.

ATTACHMENT: Staff Report

ATTACHMENT: 2024 HMIS Northern Nevada Application Draft

19. Approve and authorize the submission of a grant application to the U.S. Department of Housing and Urban Development (HUD) for the Rural Nevada Continuum of Care (CoC) Homeless Management Information System (HMIS) Project, by Clark County Social Service (CCSS), in the amount of $92,741 and $23,185 in Emergency Solutions Grant (ESG) cash match from Nevada Housing Division, to provide software and administration; and authorize the Deputy County Manager, or her designee, to accept any grant funds awarded. (For possible action)

ACTION: APPROVED.

ATTACHMENT: Staff Report

ATTACHMENT: 2024 HMIS Rural Nevada Application Draft

20. Approve and authorize the submission of a renewal grant application to the U.S. Department of Housing and Urban Development (HUD) for the Southern Nevada Continuum of Care (CoC) Homeless Management Information System (HMIS) Project, by Clark County Social Service (CCSS), in the amount of $980,154 to provide for the current software system; and authorize the Deputy County Manager, or her designee, to accept any grant funds awarded. (For possible action)

ACTION: APPROVED.

ATTACHMENT: Staff Report

ATTACHMENT: 2024 HMIS Southern Nevada Application Draft

Environment and Sustainability

21. Set a public hearing on November 5, 2024, at 10:00 a.m. to approve, adopt, and authorize submittal of the "2015 Ozone NAAQS Attainment Plan for the Las Vegas Valley Moderate Nonattainment Area: Clark County, NV" to the State of Nevada for submission to the U.S. Environmental Protection Agency for review and approval as a revision to the Nevada State Implementation Plan. (For possible action)

ACTION: APPROVED.

3.0 BOARD OF COUNTY COMMISSIONERS MEETING – 11/5/2024 (CONDUCT PUBLIC HEARING)

3.1 AGENDA ITEM

CLARK COUNTY BOARD OF COMMISSIONERS
AGENDA ITEM

Petitioner: Marci Henson, Director, Department of Environment and Sustainability

Recommendation:

Conduct a public hearing; approve, adopt, and authorize the "2015 Ozone NAAQS Attainment Plan for the Las Vegas Valley Moderate Nonattainment Area: Clark County, NV," and authorize the Director or her designee to submit the plan, including any relevant public comments, to the State of Nevada for submission to the U.S. Environmental Protection Agency for review and approval as a revision to the Nevada State Implementation Plan. (For possible action)

FISCAL IMPACT:

Fund #:	N/A	Fund Name:	N/A
Fund Center:	N/A	Funded PGM/Grant:	N/A
Amount:	N/A		
Description:	N/A		
Additional Comments:	N/A		

BACKGROUND:

On October 1, 2015, the U.S. Environmental Protection Agency (EPA) revised the 8-hour ozone National Ambient Air Quality Standard (NAAQS), lowering both the primary and secondary standards from 0.075 to 0.070 parts per million. The Las Vegas Valley (Hydrographic Area 212) was designated as a marginal nonattainment area for the 2015 ozone standard, effective August 3, 2018. On January 5, 2023, EPA determined that the area failed to attain the 2015 ozone NAAQS by the applicable marginal nonattainment date and reclassified the Las Vegas Valley as a moderate nonattainment area. The reclassification notice established a submission deadline of January 1, 2023, for the area's moderate attainment plan. On October 18, 2023, EPA issued a finding of failure to submit a moderate attainment plan for the Las Vegas Valley nonattainment area by the submission deadline.

Under Sections 172 and 182(b) of the Clean Air Act, Clark County is required to submit a state implementation plan (SIP) that meets the following planning requirements for moderate nonattainment areas: emission inventories, attainment demonstration, nonattainment new source review, 15% rate of progress, reasonably available control measures, reasonably available control technology, motor vehicle inspection and maintenance, contingency measures, and a motor vehicle emissions budget for transportation conformity. The attached plan is intended to satisfy EPA's requirements for moderate nonattainment areas and resolve its finding of failure to submit. The plan and all attachments may be reviewed at the following link: https://publicinput.com/e58566.

The plan was made available for public comment from August 15 through September 16, 2024, on the Department of Environment and Sustainability, Division of Air Quality's website. One comment was received. Attachment K documents the public review process. Information not yet included in Attachment K will be added after the public hearing and upon Board approval of this plan.

Staff requests the Board approve and adopt this plan and authorize staff to submit it to the State of Nevada and EPA for approval as a revision to the Nevada SIP.

Cleared for Agenda
11/05/2024
File ID#
24-1411

3.2 PUBLIC COMMENT REPORT

Public Hearing:	November 5, 2024
Formal Comments Received during Public Hearing:	None

3.3 MEETING SUMMARY

VOTE: 7

Voting Aye:	Tick Segerblom Jim Gibson William McCurdy II Marilyn Kirkpatrick Ross Miller Michael Naft Justin Jones
Voting Nay:	None
Absent:	None
Abstain:	None

49. Conduct a public hearing; approve, adopt, and authorize the "2015 Ozone NAAQS Attainment Plan for the Las Vegas Valley Moderate Nonattainment Area: Clark County, NV." and authorize the Director or her designee to submit the plan, including any relevant public comments, to the State of Nevada for submission to the U.S. Environmental Protection Agency for review and approval as a revision to the Nevada State Implementation Plan. (For possible action)

MOVED BY: Jim Gibson

ACTION: APPROVED.

VOTE: 7

Voting Aye:	Tick Segerblom Jim Gibson William McCurdy II Marilyn Kirkpatrick Ross Miller Michael Naft Justin Jones
Voting Nay:	None
Absent:	None
Abstain:	None

50. Conduct a public hearing and approve, adopt, and authorize the Chair to sign an ordinance to amend Clark County Code Title 8, Chapter 8.20 and Chapter 8.24 regarding the handling, transport, and delivery of liquor; adding a new section to provide for the licensure of liquor delivery support services; revising the exceptions for the off-premises delivery of alcohol by package liquor licensees to include liquor stores, grocery stores, and liquor delivery support services; adding a section to prohibit the employment of minors to sell or handle liquor; establishing operational requirements for the delivery of liquor to a consumer in certain areas by a grocery store, liquor store, or a liquor delivery support service; requiring work identification cards for any person employed by a liquor delivery support service; and providing for other matters properly related thereto. Commission District: All (For possible action) (Sitting as Liquor and Gaming Licensing Board)

ACTION: DELETED.