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NEW MEXICO OZONE ATTAINMENT INITIATIVE PHOTOCHEMICAL MODELING STUDY – DRAFT FINAL AIR QUALITY TECHNICAL SUPPORT DOCUMENT



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ACRONYMS AND ABBREVIATIONS

3SAQS	Three-State Air Quality Study
AIRS	Aerometric Information Retrieval System
AMET	Atmospheric Model Evaluation Tool
APCA	Anthropogenic Precursor Culpability Assessment
AQ	Air Quality
AQS	Air Quality System
AQTSD	Air Quality Technical Support Document
BC	Boundary Condition
BLM	Bureau of Land Management
CAMx	Comprehensive Air-quality Model with extensions
CARB	California Air Resources Board
CASTNet	Clean Air Status and Trends Network
CB6r2	Carbon Bond mechanism version 6, revision 2
CMAQ	Community Multiscale Air Quality modeling system
CONUS	Continental United States
CPC	Center for Prediction of Climate
CSAPR	Cross State Air Pollution Rule
CSN	Chemical Speciation Network
DV	Ozone Design Value
DVC	Current Year Ozone Design Value
DVF	Future Year Ozone Design Value
EC	Elemental Carbon Fine Particulate Matter
ECMWF	European Center for Medium Range Weather Forecasting
EGU	Electrical Generating Units
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency
ERA5	ECMWF global hourly meteorological forecasts at 30-km
ERG	Eastern Research Group
FB	Fractional Bias
FE	Fractional Error
FRM	Federal Reference Method
GCM	Global Chemistry Model
GEOS-Chem	Goddard Earth Observing System (GEOS) global chemistry model
GIRAS	Geographic Information Retrieval and Analysis System
IMPROVE	Interagency Monitoring of PROtected Visual Environments
IWDW	Intermountain West Data Warehouse
LCC	Lambert Conformal Conic projection
LSM	Land Surface Model
MADIS	Meteorological Assimilation Data Ingest System
MATS	Modeled Attainment Test Software
MCIP	Meteorology-Chemistry Interface Processor
MEGAN	Model of Emissions of Gases and Aerosols in Nature
MNGE	Mean Normalized Gross Error
MNB	Mean Normalized Bias
MNE	Mean Normalized Error
MOVES	Motor Vehicle Emissions Simulator
MOZART	Model for OZone And Related chemical Tracers

MPE	Model Performance Evaluation
MSKF	Multi-Scale Kain-Fritsch Cumulus Parameterization
NAAQS	National Ambient Air Quality Standard
NAM	North American Mesoscale Forecast System
NCAR	National Center for Atmospheric Research
NCEP	National Center for Environmental Prediction
NCDC	National Climatic Data Center
NEI	National Emissions Inventory
NEPA	National Environmental Policy Act
NH ₄	Ammonium Fine Particulate Matter
NMB	Normalized Mean Bias
NME	Normalized Mean Error
NMED	New Mexico Environmental Department
NO ₂	Nitrogen Dioxide
NO ₃	Nitrate Fine Particulate Matter
NOAA	National Oceanic and Atmospheric Administration
OA	Organic Aerosol Fine Particulate Matter
OAI	Ozone Attainment Initiative
OC	Organic Carbon Fine Particulate Matter
OSAT	Ozone Source Apportionment Technology
O&G	Oil and Gas
PAVE	Package for Analysis and Visualization
PBL	Planetary Boundary Layer
PGM	Photochemical Grid Model
PM	Particulate Matter
PPB	Parts Per Billion
PPM	Parts Per Million
PPM	Piecewise Parabolic Method
QA	Quality Assurance
QC	Quality Control
RMP	Resource Management Plan
RRF	Relative Response Factor
SCC	Source Classification Code
SIP	State Implementation Plan
SMAT	Software for Modeled Attainment Test
SMOKE	Sparse Matrix Kernel Emissions modeling system
SNMOS	Southern New Mexico Ozone Study
SOA	Secondary Organic Aerosol
SO ₂	Sulfur Dioxide
SO ₄	Sulfate Fine Particulate Matter
TCEQ	Texas Commission on Environmental Quality
UNC-IE	University of North Carolina Institute for the Environment
USFS	United States Forest Service
VERDI	Visualization Environment for Rich Data Interpretation
VMT	Vehicle Miles Traveled
WBD	Wind Blown Dust model
WAQS	Western Air Quality Study
WESTAR	Western States Air Resources Council
WestJumpAQMS	West-Wide Jump-Start Air Quality Modeling Study

WESTUS	Western United States
WRAP	Western Regional Air Partnership
WGA	Western Governors' Association
WRF	Weather Research Forecast model

1. INTRODUCTION

This is a draft final Air Quality Technical Support Document (AQTSD) for the New Mexico (NM) Ozone Attainment Initiative (OAI) Photochemical Modeling Study (“NM OAI Study”). The NM OAI Study has developed a 2014 base year photochemical grid model (PGM) modeling platform and conducted 2028 future year modeling for a Base Case and an Oil and Gas (O&G) Control Strategy scenario that implemented proposed controls on 2028 New Mexico O&G sources. The New Mexico Environmental Department (NMED) has contracted with a team consisting of Western States Air Resources Council (WESTAR) and Ramboll US Corporation (Ramboll) to conduct the NM OAI Study.

The NM OAI Study leverages the 2014 PGM modeling platform developed by the Western Regional Air Partnership (WRAP) in the Western Air Quality Study (WAQS) and enhances it by adding a 4-km grid resolution modeling domain covering New Mexico and adjacent regions. The NM OAI Study AQTSD documents the 2014 base case, 2028 future year base case and 2028 NM O&G control strategy modeling and includes a summary of the development of the 2014 PGM modeling platform with more details found on the NM OAI Study Website¹ and reports:

- New Mexico Ozone Attainment Initiative Photochemical Modeling Study – Draft Modeling Protocol (Ramboll and WESTAR, 2020a).²
- New Mexico Ozone Attainment Initiative Photochemical Modeling Study – Draft Work Plan (Ramboll and WESTAR, 2020b).³
- New Mexico Ozone Attainment Initiative Photochemical Modeling Study – 2014 Modeling Platform Development and Model Evaluation (Ramboll and WESTAR 2020c).⁴
- New Mexico Ozone Attainment Initiative Photochemical Modeling Study – Revised 2014v2 Base Case and Model Performance Evaluation (Ramboll and WESTAR, 2021).⁵

Although the WESTAR/Ramboll team conducted the 2014 base year and 2028 base and O&G Control Strategy future year modeling, the implementation of the proposed NMED O&G ozone precursor control strategy in the 2028 O&G emissions was conducted by Eastern Research Group (ERG) under separate contract with NMED so is not documented in this report.

1.1 NM OAI Photochemical Modeling Study Genesis

The NMED Air Quality Bureau has authority over air quality management activities throughout the state of New Mexico, with the exception Bernalillo County and Tribal Lands. The City of Albuquerque/Air Quality Division has authority in Bernalillo County and, except for where Tribal Implementation Plans have been approved, EPA oversees air quality issues in Tribal Lands. The New Mexico Air Quality Control Act (NMAQCA) requires the NMED to develop a plan to address elevated ozone levels when air quality

¹ <https://www.wrapair2.org/NMOAI.aspx>

² https://www.wrapair2.org/pdf/NM_OAI_Modeling_Protocol_v5.pdf.

³ https://www.wrapair2.org/pdf/NM_OAI_Work_Plan_v2.pdf

⁴ https://www.wrapair2.org/pdf/NM_OAI_2014_BaseCase_MPE_v3.pdf

⁵ <https://www.wrapair2.org/NMOAI.aspx>

is within 95% of the ozone NAAQS (74-3-5.3, NMSA 1978⁶). The ozone NAAQS was revised in 2015 with a threshold of 0.070 ppm (70 ppb) with the relevant metric being the ozone Design Value (DV) that is expressed as the three-year average of the fourth highest Maximum Daily Average 8-hour (MDA8) ozone concentrations. Table 1-1 lists the observed ozone DVs at New Mexico monitoring sites from 2010 to 2019. The DVs are color-coded when they exceed the 75 ppb 2008 ozone NAAQS (red), 70 ppb 2015 ozone NAAQS (yellow) and within 95% of the 70 ppb ozone NAAQS (green, i.e., ≥ 67 ppb). In more recent years, the ozone DVs have exceeded the 70 ppb 2015 ozone NAAQS at several sites in southern New Mexico (e.g., in Doña Ana and Eddy Counties). In particular, the 2017-2019 ozone DVs are particularly high and even exceeded the 75 ppb 2008 ozone NAAQS at three sites in southern New Mexico (colored red in Table 1-1).

⁶ <https://law.justia.com/codes/new-mexico/2017/chapter-74/article-2/section-74-2-5.3/>

Table 1-1. Ozone design values (ppm) at sites in New Mexico from 2010 to 2019. Red above the 75 ppb 2008 NAAQS, yellow above 2015 70 ppb NAAQS and green within 95% of the 2015 NAAQS.

AQS Site ID	Local Site Name	County Name	2008-2010	2009-2011	2010-2012	2011-2013	2012-2014	2013-2015	2014-2016	2015-2017	2016-2018	2017-2019
350010023	Del Norte HS	Bernalillo	0.064	0.066	0.068	0.070	0.068	0.066	0.065	0.067	0.070	0.070
350010024	SE Heights	Bernalillo	0.066	0.068	0.070	0.070	0.068					
350010027	Westside	Bernalillo	0.067	0.068	0.071	0.071						
350010029	South Valley	Bernalillo	0.066	0.067	0.069	0.070	0.067	0.066	0.065	0.065	0.066	0.067
350010032	Westside	Bernalillo			0.070	0.070	0.067					
350011012	Foothills	Bernalillo	0.068	0.070	0.074	0.072	0.067	0.064	0.064	0.067	0.069	0.071
350011013	North Valley	Bernalillo	0.067	0.068	0.069	0.069						
350130008	La Union	Doña Ana	0.064	0.062	0.065	0.067	0.067	0.066	0.066	0.068	0.068	0.070
350130017	Sunland Park	Doña Ana	0.064	0.065	0.068	0.067	0.067					
350130020	Chaparral	Doña Ana	0.066	0.067	0.067	0.069	0.068	0.067	0.066	0.068	0.071	0.073
350130021	Desert View	Doña Ana	0.070	0.069	0.072	0.072	0.072	0.072	0.072	0.072	0.074	0.077
350130022	Santa Teresa	Doña Ana	0.067	0.066	0.070	0.075	0.074	0.072	0.068	0.072	0.074	0.076
350130023	Solano	Doña Ana	0.063	0.063	0.065	0.065	0.065	0.065	0.065	0.066	0.067	0.070
350151005	Carlsbad City	Eddy	0.067	0.068	0.071	0.071	0.071	0.069	0.067	0.068	0.074	0.079
350153001	Carlsbad Caverns	Eddy									0.071	
350171003	Chino Copper	Grant	0.063	0.065	0.067	0.063	0.062					
350250008	Hobbs Jefferson	Lea	0.059	0.061	0.061	0.066	0.065	0.067	0.066	0.067	0.070	0.071
350290003	Deming Airport	Luna	0.057	0.058	0.064	0.067	0.066					
350390026	Coyote Ranger District	Rio Arriba							0.064	0.065	0.067	0.067
350431001	Bernalillo	Sandoval	0.060	0.061	0.061	0.063	0.063	0.065	0.064	0.065	0.068	0.068
350439004	Pueblo of Jemez	Sandoval		0.062								
350450009	Bloomfield	San Juan	0.060	0.061	0.067	0.068	0.067	0.064	0.062	0.064	0.069	0.068
350450018	Navajo Lake	San Juan			0.071	0.071	0.068	0.067	0.066	0.068	0.070	0.069
350451005	Substation	San Juan	0.063	0.063	0.067	0.068	0.066	0.063	0.062	0.064	0.069	0.069
350490021	Santa Fe Airport	Santa Fe	0.063	0.062	0.065	0.066	0.066	0.064	0.063	0.063	0.066	0.066
350610008	Los Lunas	Valencia			0.067	0.070	0.069	0.066	0.064	0.065	0.067	0.068

To address the high observed ozone concentrations in New Mexico, the NMED has embarked on an Ozone Attainment Initiative (OAI⁷) to protect the ozone attainment status of the state and ensure health and welfare of the residents of the state for future generations. The OAI was initiated in Spring 2018. As part of the OAI, NMED released a Request for Proposal (RFP#20 667 4040 0001) for the NM OAI Study and the NM OAI Study PGM modeling was awarded to a contracting team of WESTAR and Ramboll.

⁷ <https://www.env.nm.gov/air-quality/o3-initiative/>

1.2 Overview of NM OAI Study Modeling Approach

The procedures used for the NM OAI Study photochemical modeling were described in a detailed Modeling Protocol dated May 19, 2020 (Ramboll and WESTAR, 2020a). A description of the tasks and schedule for completing the NM OAI Study is contained in a Work Plan (Ramboll and WESTAR, 2020b) with presentations, results and reports posted to the NM OAI Study webpage⁸ as they are produced. One objective of the study was to evaluate a proposed regulation to control ozone precursor emissions from oil and gas (O&G) development sources in New Mexico. The original future year emissions scenario in the NM OAI Study was 2023, when the proposed O&G rule would not be fully implemented. Thus, the future year to be modeled was changed to 2028 in a December 2020 Contract Amendment from NMED to the WESTAR/Ramboll team.

The NM OAI Study is conducting PGM modeling by enhancing the WRAP-WAQS 2014v2 36/12-km PGM modeling platform⁹ with the addition of a new 4-km grid resolution domain covering New Mexico and surrounding areas, especially the O&G production regions in the Permian and San Juan Basins. The NM OAI Study PGM modeling is performing 2014 base year modeling and model performance evaluation. 2028 future year modeling was also conducted. The NM OAI Study PGM modeling is being conducted in accordance with EPA's guidance for ozone State Implementation Plan (SIP) ozone attainment demonstration modeling (EPA, 2018).

1.2.1 WRAP-WAQS 2014 PGM Platform Development

The WRAP-WAQS developed an annual 2014 PGM modeling platform to address air quality issues in the western states. An initial WRAP-WAQS 2014v1 PGM modeling platform was developed in 2019 for the CAMx and CMAQ PGMs that is documented in a webpage¹⁰ on the Intermountain West Data Warehouse (IWDW). Additional diagnostic sensitivity tests were conducted to address several model performance issues culminating in the WRAP-WAQS 2014v2 36/12-km CAMx modeling database that was used as the starting point for the NM OAI Study CAMx summer of 2014 36/12/4-km modeling database. The development of the WRAP-WAQS 2014v2 PGM database and model performance evaluation is available in a webpage¹¹ on the IWDW.

The WRAP-WAQS 2014v2 CAMx platform used a 36/12-km grid resolution domain structure with meteorological inputs based on the WAQS 2014 36/12-km WRF meteorological model simulation (Bowden, Talgo and Adelman, 2016¹²). The 2014 emissions were based on the 2014 National Emissions Inventory (2014NEI¹³) with updates from western states¹⁴. Boundary Condition (BC) inputs were based on a WRAP 2014 GEOS-Chem model simulation.

Because the NM OAI Study requires a 4-km modeling domain for New Mexico, new summer of 2014 36/12/4-km WRF meteorological modeling was conducted, as

⁸ <https://www.wrapair2.org/NMOAI.aspx>

⁹ <http://views.cira.colostate.edu/wiki#WAQS-2014-Modeling-Platform>

¹⁰ http://views.cira.colostate.edu/iwdw/docs/waqs_2014v1_shakeout_study.aspx

¹¹ https://views.cira.colostate.edu/iwdw/docs/WRAP_WAQS_2014v2_MPE.aspx

¹² http://views.cira.colostate.edu/wiki/Attachments/Modeling/WAQS_2014_WRF_MPE_January2016.pdf

¹³ <https://www.epa.gov/air-emissions-inventories/2014-national-emissions-inventory-nei-data>

¹⁴

https://www.wrapair2.org/pdf/WRAP%20Regional%20Haze%20SIP%20Emissions%20Inventory%20Review%20Documentation_for_Docket%20Feb2019.pdf

described in Chapter 2, that was used to develop 36/12/4-km meteorological inputs for CAMx. The NM OAI Study defined their 36/12-km domains to match WRAP-WAQS 2014v2 36/12-km domains so the WRAP-WAQS 2014v2 36/12-km emission and some other inputs (e.g., BCs) can be used directly in the NM OAI Study PGM modeling. Figure 1-1 shows the 36/12/4-km modeling domains used for the NM OAI Study PGM modeling with the 4-km grid resolution New Mexico domain shown in Figure 1-2.

1.2.2 Episode Selection

The May-August 2014 modeling period was selected as it has a high quality emissions inventory with western state updates and has a PGM platform already developed from the WRAP-WAQS regional haze modeling that can be leveraged for the NM OAI Study. Details on the episode selection are contained in Chapter 3 of the NM OAI Study Modeling Protocol (Ramboll and WESTAR, 2020a).

1.2.3 Model Selection

Details on the rationale for model selection are provided in Chapter 2 of the NM OAI Study Modeling Protocol (Ramboll and WESTAR, 2020a). The Weather Research Forecast (WRF) prognostic meteorological model was selected. Emissions modeling was conducted using the Sparse Matric Operator Kernel Emissions (SMOKE) model for most source categories. The Model of Emissions of Gases and Aerosols from Nature (MEGAN v3.1) was used initially for biogenic emissions in the 4-km domain for the original CAMx 2014 Base Case, but was ultimately replaced by biogenic emission based on the BEIS v3.7 model in the final CAMx 2014v2 base case. There are special processors for fires, windblown dust (WBD), lightning NO_x (LNO_x) and oceanic sea salt (NaCl) and Dimethyl Sulfide (DMS) emissions that were used. The 2014 version of the Motor Vehicle Emissions Simulator (MOVES2014b) on-road mobile source emissions model was used with SMOKE-MOVES and WRF meteorological data to generate on-road mobile source emissions for the 4-km New Mexico modeling domain.

The Comprehensive Air-quality Model with extensions (CAMx) photochemical grid model (PGM) was used because it supports two-way grid nesting, was used in the WRAP-WAQS regional haze modeling, contains a well-vetted ozone source apportionment tool and has a rich and successful history of successful application to the region.

1.2.4 Domain Selection

The NM OAI Study modeling is using the same 36-km 36US and 12-km 12WUS2 domains as used in the WRAP-WAQS 2014 modeling platform. A new 4-km New Mexico domain was added to the 36/12-km domain structure. Figure 1-1 displays the 36/12/4-km domain structure with Figure 1-1 showing the 4-km New Mexico domain. New WRF 2014 36/12/4-km meteorological modeling was conducted to generate finer scale 4-km meteorological conditions for the New Mexico domain and consistent meteorology among the 36/12/4-km domains. The domains use a Lambert Conformal Conic (LCC) projection using the parameters given in Table 1-2 with the definitions of the extent of the 36/12/4-km domains given in Table 1-3. CAMx was run using the 36/12/4-km domain structure shown in Figure 1-1 using two-way interactive grid nesting.

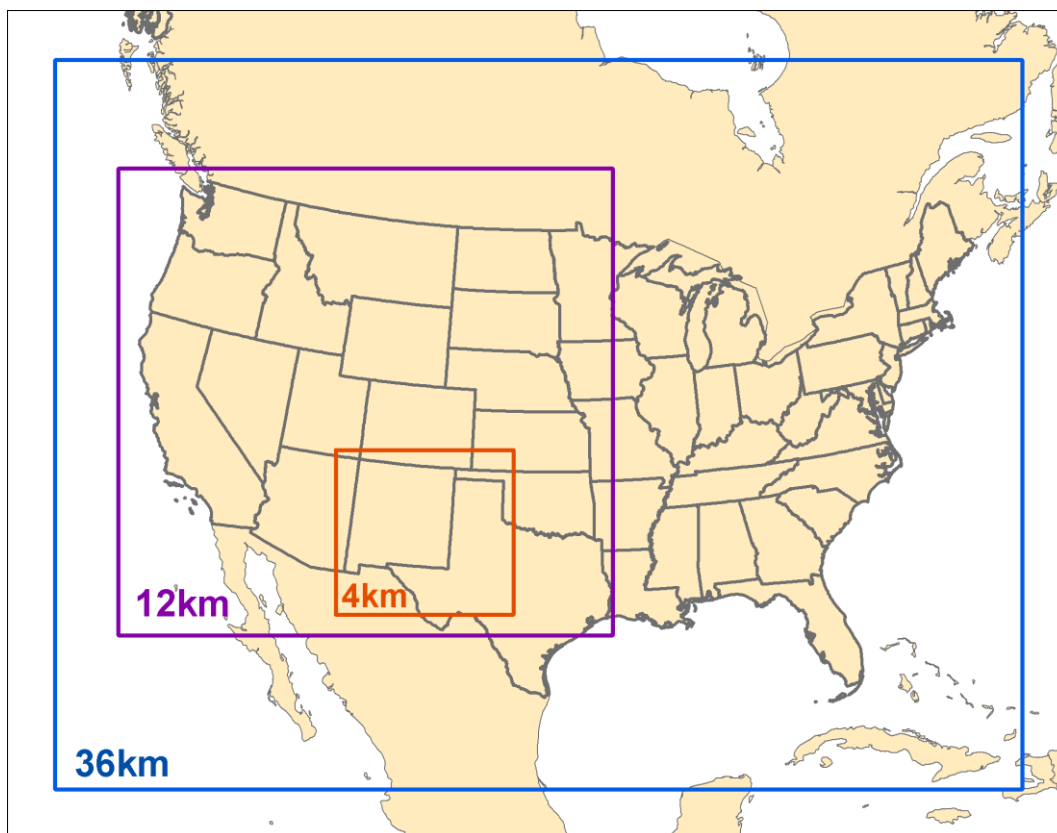


Figure 1-1. NM OAI Study 2014 36/12/4-km PGM and emissions modeling domains.

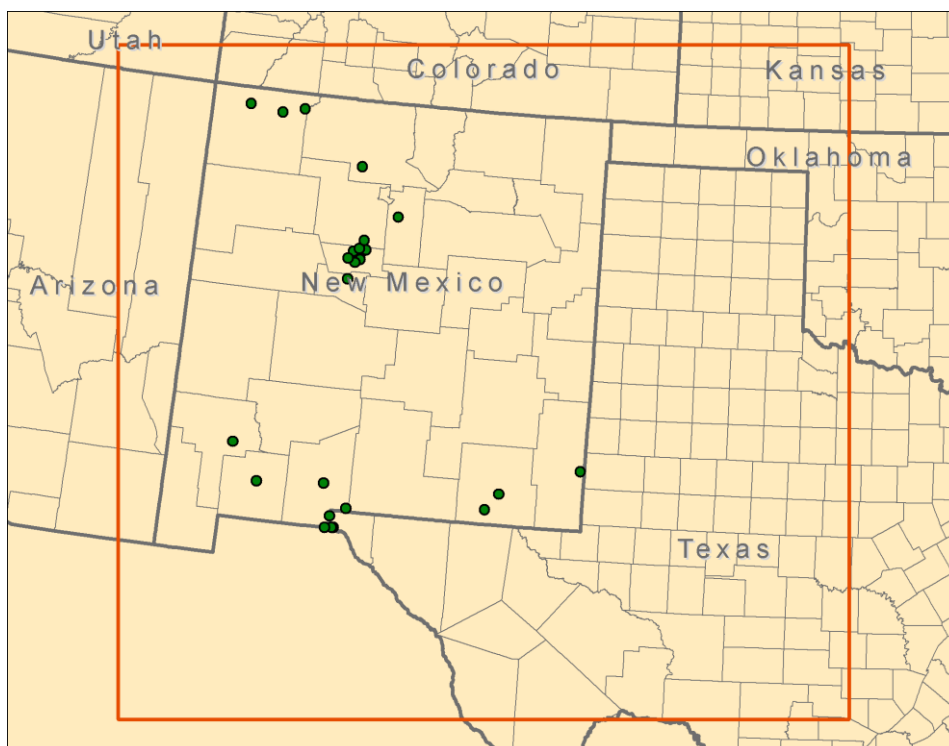


Figure 1-2. 4-km New Mexico modeling domain for PGM and emissions modeling, with locations of New Mexico ozone monitors that were operating during some portion of 2014.

Table 1-2. Lambert Conformal Conic (LCC) projection parameters for the NM OAI Study 36/12/4 modeling domains.

Parameter	Value
Projection	Lambert-Conformal
1st True Latitude	33 degrees N
2nd True Latitude	45 degrees N
Central Longitude	-97 degrees W
Central Latitude	40 degrees N

Table 1-3. Grid definitions for CAMx NM OAI Study 2014 36/12/4-km modeling domains.

Grid	Origin (SW) (km)	Extent (NE) (km)	NX	NY
36-km	(-2736, -2088)	(2592, 1944)	148	112
12-km*	(-2388, -1236)	(336, 1344)	227	215
4-km*	(-1192, -1120)	(-212, -212)	245	227

*Definition includes outer row/column of buffer cells required by CAMx for nested domains

1.2.5 Base and Future Year Emissions Data

The 2014 base year emissions data were based on the WRAP-WAQS 2014v2 emissions that were in turn based on the 2014NEIv2 with updates from western states. New emissions were generated for natural emission sources (e.g., biogenic and LNO_x). 2028 emissions were based on the WRAP 2028 On-the-Books (2028OTBa2) emissions scenario with updated 2028 O&G emissions for New Mexico and using actual 2014 fires instead of Representative Baseline fires as used in the WRAP 2028OTBa2 scenario. The development of the 2014 and 2028 emission scenarios are discussed in Chapter 4.

1.2.6 Initial and Boundary Conditions Development

The first two-weeks of May were run on the 36/12/4-km domains to spin-up the model before the first high ozone day in New Mexico (68 ppb on May 17). This washed out the influence of the initial concentrations (IC) before elevated ozone concentrations occur in New Mexico.

Boundary conditions (BC) for the outer 36-km 36US domain were based on a 2014 simulation of the GEOS-Chem global chemistry model conducted by WRAP processed by the GC2CAMx converter. The result is day-specific diurnally varying BCs for the lateral boundaries around the 36-km 36US modeling domain. The top BC was based on a zero-gradient assumption where concentrations above the top of the model (above 50 mb, or ~19-km above sea level) are assumed to be the same as in the top vertical layer of CAMx.

Due to uncertainties in projecting future year international emissions, the CAMx BCs based on the 2014 GEOS-Chem global model simulation were held constant for the 2028 modeling. This is likely a conservative estimate of 2028 BCs.

Chapter 3 provides a summary of the development of the 2014 CAMx BC inputs with more details in Ramboll and WESTAR (2020c) and on the WRAP-WAQS 2014v2 modeling website.

1.2.7 Diagnostic Sensitivity Analyses

The NM OAI Study conducted four diagnostic sensitivity tests for the CAMx 2014 36/12/4-km base case that compared the CAMx ozone performance for four alternative meteorological inputs. The NM OAI Study conducted two WRF 2014 36/12/4-km WRF simulations that used different analysis fields as input. The two 2014 36/12/4-km WRF outputs were processed with WRFCAMx using two different options for vertical turbulent exchange (i.e., vertical mixing) coefficients (Kv). This resulted in four different CAMx meteorological inputs that were evaluated using CAMx diagnostic sensitivity tests that are summarized in Chapter 5 with details provided in Ramboll and WESTAR (2020c).

1.2.8 Model Performance Evaluation

The NM OAI Study CAMx 2014 36/12/4-km base case simulation Model Performance Evaluation (MPE) followed EPA's MPE recommendations in their ozone modeling guidance (EPA, 2018) and other sources (e.g., Simon, Baker and Phillips, 2012; Emery et al., 2016). The CAMx 2014 36/12/4-km base case simulation MPE focused on ozone model performance within the 4-km New Mexico domain, and especially within New Mexico. Two CAMx 2014 base case simulations were performed and subjected to an MPE. An original CAMx 2014 base case simulation used CAMx v7.0 and biogenic

emissions in the 4-km NM domain based on the MEGAN v3.1 model whose evaluation is documented in NM OAI Study 2014 platform development and 2014 base case modeling report (Ramboll and WESTAR, 2020c). A revised 2014v2 base case was conducted using CAMx v7.1 and biogenic emissions based on the BEIS v3.7, whose results are documented in an Addendum to the 2014 base case modeling report (Ramboll and WESTAR, 2021).

1.2.9 2028 Future Year Base and Control Strategy Modeling

2028 future year ozone modeling was conducted using the WRAP 2028OTBa2 emissions scenario with updated 2028 O&G emissions in New Mexico and using 2014 actual fires instead of the Representative Baseline fires used in the 2028OTBa2 scenario. These fire inventories were prepared for the WRAP Fire and Smoke Work Group and are documented in a report (Air Sciences, 2020) and presentation.¹⁵ A CAMx 2028 future year 36/12/4-km base case simulation was conducted using CAMx v7.1 and used to project 2028 future year ozone design values (DVs). The procedures to calculate projected ozone DVs followed EPA's latest guidance (EPA, 2018). These procedures use the modeling results in a relative fashion to scale the current year observed 2012-2016 8-hour ozone design values (i.e., $DVC_{2012-2016}$) to project 2028 future year ozone Design Values (DVs). The scaling factors are called Relative Response Factors (RRFs) and are the ratio of the future-year to current-year modeling results for the 10 highest base year modeled MDA8 ozone days near the monitoring site. EPA has developed the Speciated Modeled Attainment Test (SMAT¹⁶) tool that includes the recommended procedures in the latest EPA guidance for projecting ozone DVs.

The NM OAI Study also conducted future year modeling for a 2028 O&G Control Strategy that implemented controls on ozone precursors from O&G sources within the San Juan and Permian Basins. The WESTAR/Ramboll team provided the 2028 NM O&G emissions to ERG who, under separate contract to NMED, implemented the proposed NM O&G ozone precursor control strategy in the 2028 NM O&G emissions and provided them to WESTAR/Ramboll for ozone modeling. This report does not document the implementation of the NM O&G ozone precursor control strategy as that was not performed by WESTAR/Ramboll.

1.2.10 Future Year Source Apportionment Modeling

The NM OAI Study also is conducting future year ozone source apportionment modeling for the 2028 O&G Control Strategy scenario using the CAMx ozone source apportionment tool. The CAMx 2028 Source Sector APCA ozone source apportionment modeling examined the ozone contributions of several major anthropogenic emission source sectors in New Mexico and other states as well as contributions of International anthropogenic emissions on ozone concentrations in New Mexico and is discussed in Chapter 9. CAMx 2028 VOC/NO_x Sensitivity OSAT ozone source apportionment modeling was also conducted to examine the level of VOC sensitive versus NO_x sensitive ozone formation in New Mexico and is discussed in Chapter 10.

¹⁵ https://www.wrapair2.org/pdf/FireEIandFutureScenariosResults_to_regional_planners_20200520.pptx

¹⁶ <https://www.epa.gov/scram/photochemical-modeling-tools>

2. 2014 WRF METEOROLOGICAL MODELING

The NM OAI Study conducted WRF meteorological modeling for the summer of 2014 to generate CAMx meteorological inputs for the 36/12/4-km horizontal domain structure shown in Figure 1-1.

2.1 WRF Meteorological Model

The Weather Research and Forecasting (WRF) Model is a mesoscale numerical weather prediction system designed to serve both operational forecasting and atmospheric research needs (Skamarock, 2004; 2006; Skamarock et al., 2005; 2008; 2019). The Advanced Research WRF (ARW) version of WRF was used in the NM OAI Study.

This chapter summarizes the application and evaluation of the WRF meteorological model to generate 2014 36/12/4-km meteorological inputs for CAMx photochemical grid modeling with more details provided in Chapter 2 of Ramboll and WESTAR (2020c).

2.2 WRF Horizontal Modeling Domain

The WRF 2014 36/12/4-km modeling domains were defined slightly larger than the PGM 36/12/4-km domains (Figure 1-1) so that any modeling artifacts that occur near the WRF boundaries as the boundary conditions (BCs) come into dynamic balance with the WRF numerical algorithms are not present in the PGM meteorological inputs.

2.3 WRF Model Configuration

WRF version 4.2 was used for this modeling analysis. The NM OAI Study 36/12-km WRF/PGM grid configuration (e.g., horizontal domains and vertical layer structure) was designed to be identical to the WRAP-WAQS 2014 WRF/PGM grid configuration in order to facilitate the use of data between the two studies. A 4-km domain was added covering New Mexico and adjacent regions.

The WAQS 2011/2014 WRF modeling used 36 vertical levels (35 vertical layers) from the surface to a 50 mb (hPa) height (approximately 19-km above sea level). The EPA 2014, 2015 and 2016 WRF modeling also used 35 vertical layers up to a 50 mb height.

Table 2-1 displays the 36-vertical layer structure used in the WRAP-WAQS 2011/2014 WRF modeling that was also adopted for the NM OAI Study WRF 2014 36/12/4-km modeling.

Table 2-1. WRF 36 level vertical layer structure for the NM OAI study. This is the same WRF layer structure as used in WAQS 2011/2014/2016 and EPA 2016 WRF modeling.

WRF Layer	Sigma	Pressure (mb)	Height (m)	Thickness (m)
36	0.0000	50.00	19260	2055
35	0.0270	75.65	17205	1850
34	0.0600	107.00	15355	1725
33	0.1000	145.00	13630	1701
32	0.1500	192.50	11930	1389
31	0.2000	240.00	10541	1181
30	0.2500	287.50	9360	1032
29	0.3000	335.00	8328	920
28	0.3500	382.50	7408	832
27	0.4000	430.00	6576	760
26	0.4500	477.50	5816	701
25	0.5000	525.00	5115	652
24	0.5500	572.50	4463	609
23	0.6000	620.00	3854	461
22	0.6400	658.00	3393	440
21	0.6800	696.00	2954	421
20	0.7200	734.00	2533	403
19	0.7600	772.00	2130	388
18	0.8000	810.00	1742	373
17	0.8400	848.00	1369	271
16	0.8700	876.50	1098	177
15	0.8900	895.50	921	174
14	0.9100	914.50	747	171
13	0.9300	933.50	577	84
12	0.9400	943.00	492	84
11	0.9500	952.50	409	83
10	0.9600	962.00	326	82
9	0.9700	971.50	243	82
8	0.9800	981.00	162	41
7	0.9850	985.75	121	24
6	0.9880	988.60	97	24
5	0.9910	991.45	72	16
4	0.9930	993.35	56	16
3	0.9950	995.25	40	16
2	0.9970	997.15	24	12
1	0.9985	998.58	12	12
0	1.0000	1000.00	0	

2.3.1 Vertical Coordinate

Since its inception, WRF has used the eta (sometimes called sigma or “terrain-following”) vertical coordinate system. One weakness of the eta coordinate is that variations in terrain (especially steep topography) can increase numerical errors in the model. To reduce these errors, Park et al., (2018) developed a hybrid sigma–pressure coordinate that is now included as the default vertical coordinate system for the WRF model (Skamarock et al., 2019).

For the NM OAI Study 2014 36/12/4-km WRF modeling, we used the new hybrid vertical coordinate system and a new version of the WRFCAMx processor that has been updated to use WRF’s hybrid vertical coordinate. The hybrid vertical coordinate system and use of 4-km New Mexico domain are the two biggest differences between the NM OAI Study and WRAP-WAQS 2014 WRF modeling. The WRAP-WAQS 2014 WRF/CAMx modeling did not use the hybrid vertical coordinate system in WRF because at the time it was not supported in the WRFCAMx processor.

2.3.2 Topographic Inputs

Topographic information for WRF was based on a combination of the standard WRF terrain databases and high-resolution terrain. The 36-km 36US domain used the 10-minute global data, the 12-km 12WUS2 domain used the 2-minute data, and the 4-km New Mexico domain used the 30 second data.

2.3.3 Vegetation Type and Land Use Inputs

Vegetation type and land use information used the United States Geological Survey (USGS) land use databases from the most recently released WRF databases provided with the WRF distribution. Standard WRF surface characteristics corresponding to each land use category was employed.

2.3.4 Atmospheric Data Inputs

WRF relies on other model or re-analysis output meteorological fields to provide initial and boundary conditions (IC/BC) and fields for the four-dimensional data assimilation (FDDA). FDDA refers to the nudging of the WRF meteorological fields to observed analysis fields so that the WRF meteorological fields better represent what was observed and prevent the model from drifting away from the observed meteorology. The NM OAI Study conducted two WRF simulations that used two different analysis fields that were evaluated for their performance against meteorological variables as well as their effect on CAMx ozone model performance. Both the 12-km resolution North American Model (NAM) and the ~30-km resolution European Center for Medium-Range Weather Forecasting (ECMWF) Re-Analysis (ERA5¹⁷) dataset analysis fields were used for IC/BC and FDDA in the two WRF 2014 36/12/4-km sensitivity simulations.

Analysis nudging (i.e., FDDA) was used for winds, temperature, and humidity on the 36-km and 12-km domains. Both surface and aloft nudging was used but nudging for temperature and mixing ratio was not performed within the boundary layer. Observation nudging was not used, even on the 4-km domain.

¹⁷ <https://www.ecmwf.int/en/forecasts/datasets/archive-datasets/reanalysis-datasets/era5>

The effects of the two 2014 WRF simulations on CAMx ozone performance was evaluated in diagnostic sensitivity simulations and the best performing configuration selected as the final CAMx meteorological inputs, as described in Chapter 5.

2.3.5 New Lightning Data Assimilation

More recently, the assimilation of lightning data in WRF simulations has shown to improve the locations and amounts of convective precipitation. The use of lightning detection networks, such as the National Lightning Detection Network (NLDN), have been used in WRF simulations and used to force deep convection (thunderstorms) when lightning is observed and only allow shallow convection when lightning is not present. The use of the new lightning assimilation approach has been demonstrated to improve both WRF convective precipitation as well as PGM concentration and deposition performance (Heath et al., 2016). The new lightning data assimilation algorithm was not used in the NM OAI Study 2014 WRF modeling for the following reasons: (1) it would have to be tested and evaluated and there is insufficient time in the schedule to conduct such diagnostic testing; (2) the NLDN data used to date with the WRF lightning assimilation is a commercial product that is expensive and not within the budget; (3) the implementation of the lightning detection data assimilation in WRF has a flaw that it doesn't distinguish between no lightning detects and missing data and suppresses convection in areas with missing data (e.g., over the Gulf of Mexico); and (4) most importantly, the lightning detection data assimilation algorithm has not been implemented in the latest versions of WRF so its use would limit the use of other model new options, such as the hybrid vertical coordinate system.

2.3.6 PBL and LSM Physics Options

As used in the WRAP-WAQS 2014 WRF modeling, the YSU Planetary Boundary Layer (PBL) and Noah Land Surface Model (LSM) physics options were used in the NM OAI Study 2014 36/12/4-km WRF modeling. Previous WRF sensitivity modeling for the intermountain west region found the YSU/Noah PBL/LSM schemes produces the most realistic meteorological fields. Note that EPA's 2014/2015/2016 WRF modeling uses the ACM2 PBL and Pleim-Xiu (PX) LSM schemes (EPA, 2019).

2.3.7 Remaining WRF Physics Options

Table 2-2 lists the remaining WRF physics options for the NM OAI Study 2014 36/12/4-km WRF application. These are standard WRF physics options and consistent with the WRF options used in the WRAP-WAQS 2014 and EPA 2014/2015/2016 WRF modeling. Our comparison of 2014 WRAP-WAQS and 2014 EPA WRF modeling for summertime precipitation performance in New Mexico found that the WRAP-WAQS WRF meteorological model performance was better than EPA WRF for most variables. Therefore, we used the same microphysics and cumulus schemes for the NM OAI Study as used in 2014 WRAP-WAQS (Thompson and Multi-Scale Kain-Fritsch, respectively) and most of the same other physics options (see Table 2-2).

Table 2-2. NM OAI Study 2014 WRF model configuration and comparison with the WRF configuration used in the WRAP-WAQS 2014 and EPA 2014/2015/2016 WRF modeling.

WRF Option	NM OAI Study	2014 WRAP-WAQS	2014 EPA
Horizontal Domains	36/12/4-km	36/12/4-km	12-km
Vertical Coordinate	Hybrid Sigma	Sigma	Sigma
Microphysics	Thompson	Thompson	Morrison 2
LW Radiation	RRTMG	RRTMG	RRTMG
SW Radiation	RRTMG	RRTMG	RRTMG
Sfc Layer Physics	MM5 similarity	MM5 similarity	MM5 similarity
LSM	Noah	Noah	Pleim-Xiu
PBL scheme	Yonsei University (YSU)	YSU	ACM2
Cumulus	36/12/4-km Multi-scale Kain Fritsch	36/12-km Multi-scale_Kain Fritsch; 4-km None	Kain-Fritsch
BC, IC Analysis Nudging Source	36/12-km NAM & ERA5	36/12-km NAM	12-km NAM
Analysis Nudging Grids	36/12-km	36/12-km	12-km
Obs Nudging	None	4-km	None
Sea Sfc Temp	FNMOC	FNMOC	FNMOC

2.3.8 Application Methodology

The WRF model was executed in 5.5-day blocks initialized at 12Z every five days. Model results were output every 60 minutes, split at twelve (12) hour intervals. Twelve (12) hours of spin-up is included in each 5-day block before the data is used in the subsequent evaluation and PGM meteorological inputs.

2.4 WRF Model Evaluation

Quantitative and qualitative evaluations of the NM OAI Study 2014 WRF 36/12/4-km simulation meteorological performance was conducted for both the WRF/NAM and WRF/ERA5 applications. The quantitative evaluations compare integrated surface hourly meteorological observations with WRF predictions matched by time and location and included the calculation of model performance statistical metrics that were compared against performance benchmarks. The qualitative evaluations compared time series plots of modeled wind speed and wind direction to the observations at specific sites. The qualitative evaluation also compared spatial plots of WRF precipitation estimates against spatial maps of precipitation analysis fields based on observations

2.4.1 Quantitative Evaluation Using METSTAT

METSTAT was used to evaluate the WRF/NAM and WRF/ERA model performance against observed surface meteorological observations of wind speed and direction, temperature and mixing ratio (humidity). Figure 2-1 displays the WRF/NAM and WRF/ERA5 wind speed soccer plot that compares monthly measures of wind speed bias and error across surface monitoring sites in New Mexico with the simple and complex performance benchmarks. The monthly wind speed performance of the two WRF simulations are remarkably similar with both having near zero bias that achieves the simple benchmark ($\leq \pm 0.5$ m/s). The error (RMSE) for the two WRF simulations falls between the simple

and complex benchmarks (i.e., between 2.0 and 2.5 m/s) for all four months (May through August).

The monthly wind direction bias and error statistics for the two WRF simulations are also nearly identical with bias values of ~ 5 degrees that achieves the $\leq \pm 5$ degree simple benchmark and error statistics that falls between the 30 degree simple and 50 degree complex benchmarks (Figure 2-2).

There are differences in the two WRF simulations temperature performance and more differences in the monthly values than seen for winds (Figure 2-3). The WRF/ERA5 simulations has a near zero temperature bias in May and June with the bias and error achieving the simple benchmark for both months. The WRF/NAM has a warm bias for May and June that straddle the simple benchmark upper bound ($+0.5$ K). The two WRF simulations have similar July and August performance that have a warm bias of ~ 1.0 K that fails to achieve the simple benchmark. For both WRF simulations, the temperature bias is right at, but mostly within, the 2.0 K simple benchmark.

The WRF/ERA5 clearly has better surface humidity performance than WRF/NAM (Figure 2-4). For July and August, the WRF/NAM has a wet bias in July and August of ~ 1.5 g/kg so fails to achieve the simple ($\leq \pm 0.8$ g/kg) and complex ($\leq \pm 1.0$ g/kg) bias benchmarks. The WRF/ERA5 also has a wet bias for July and August that is not as large as WRF/NAM as it is right at the simple benchmark (~ 1.0 g/kg) but achieving the complex benchmark. The WRF/ERA5 also has better humidity error performance in July and August, although both simulations achieve the error performance benchmarks.

The two WRF simulations have better humidity performance in May and June that achieves the simple benchmark, albeit with a moist bias. May is the best performing month with nearly identical humidity model performance with a bias of ~ 0.6 g/kg and error of ~ 0.9 g/kg. In June, the WRF/ERA5 humidity performance is slightly better than WRF/NAM.

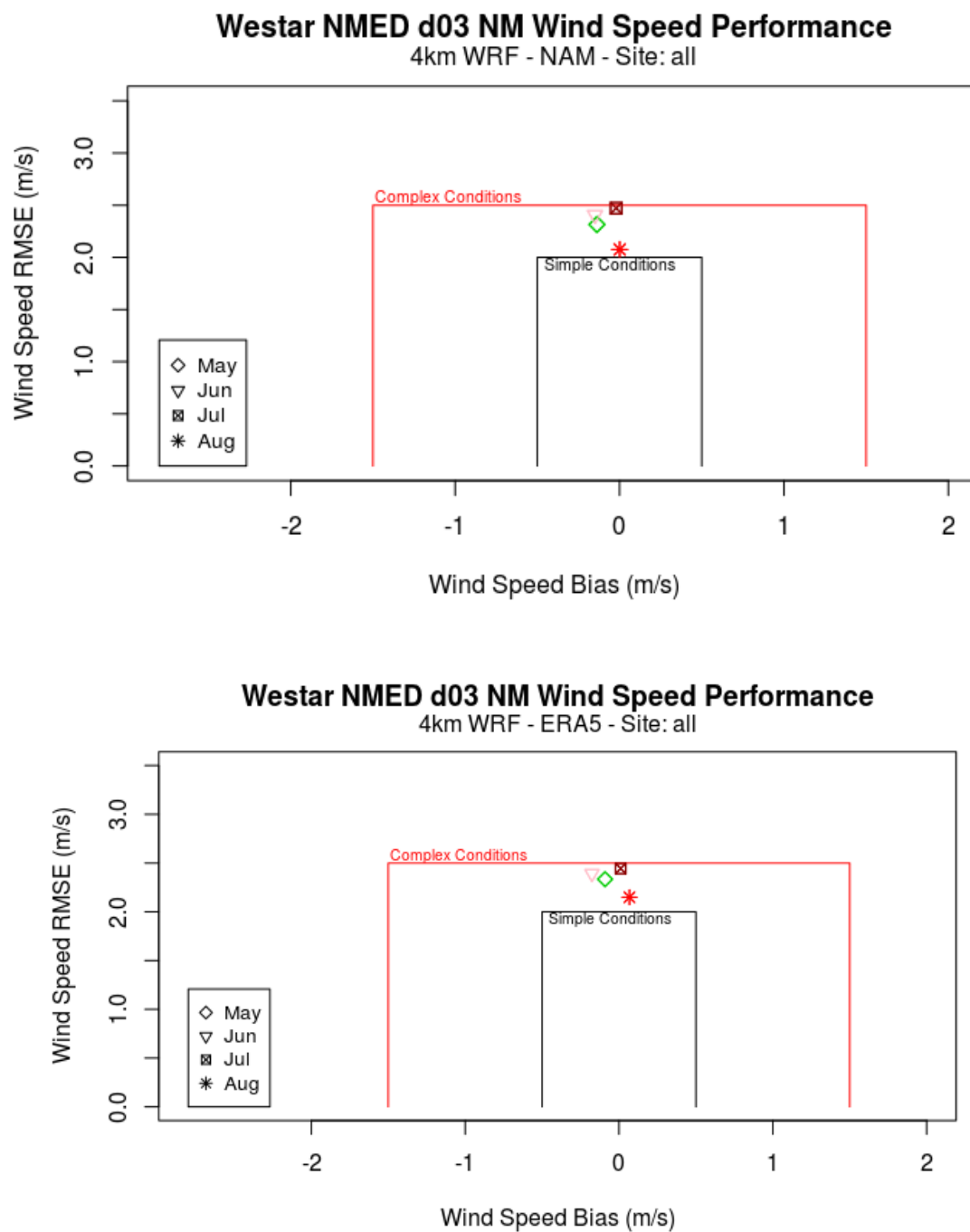


Figure 2-1. Soccer plot comparing WRF/NAM (top) and WRF/ERA5 (bottom) surface wind speed (m/s) model performance against the Simple and Complex Benchmarks for monthly RMSE (y-axis) and Mean Bias (x-axis).

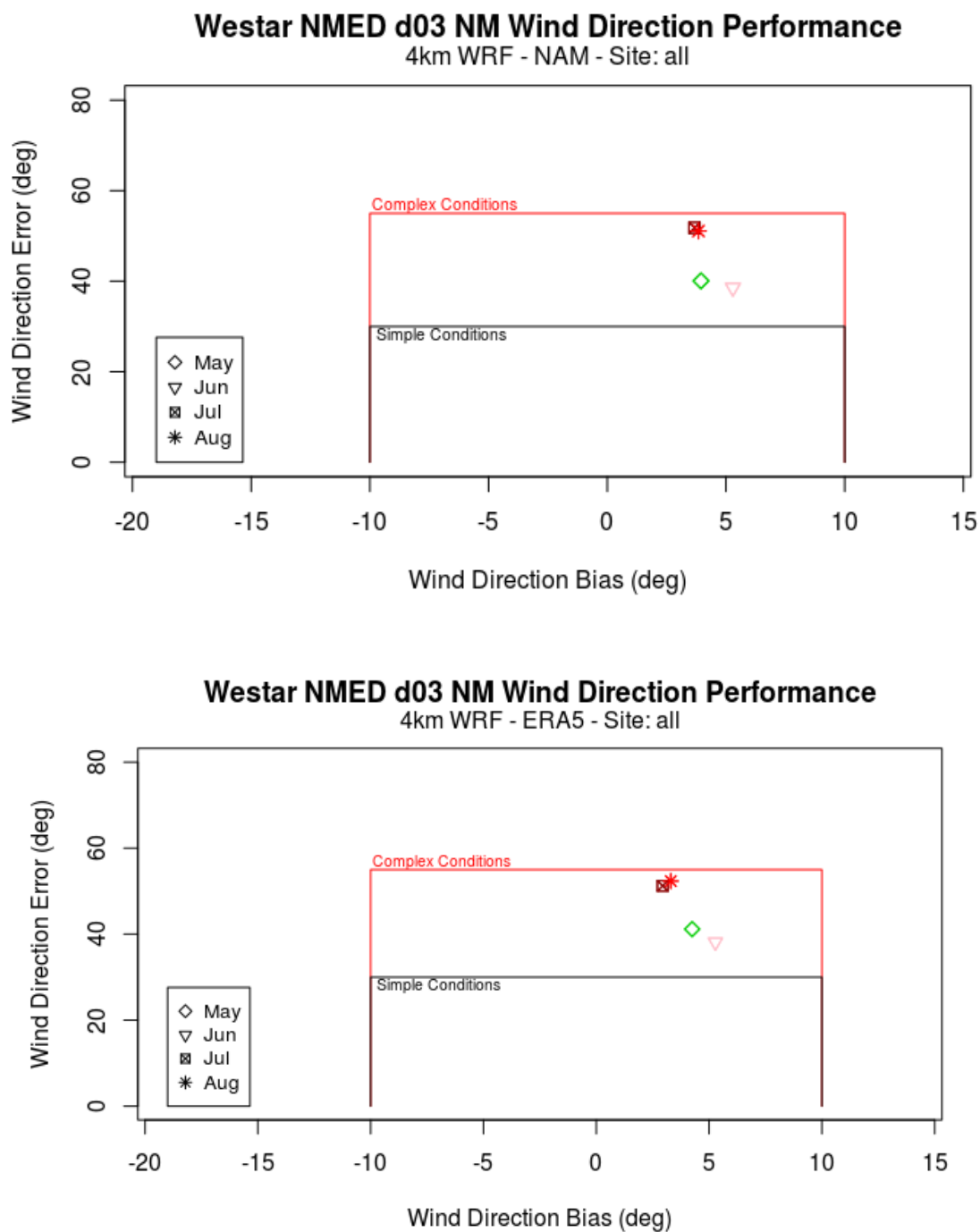


Figure 2-2. Soccer plot comparing WRF/NAM (top) and WRF/ERA5 (bottom) surface wind direction (degrees) model performance against the Simple and Complex Benchmarks for monthly RMSE (y-axis) and Mean Bias (x-axis).

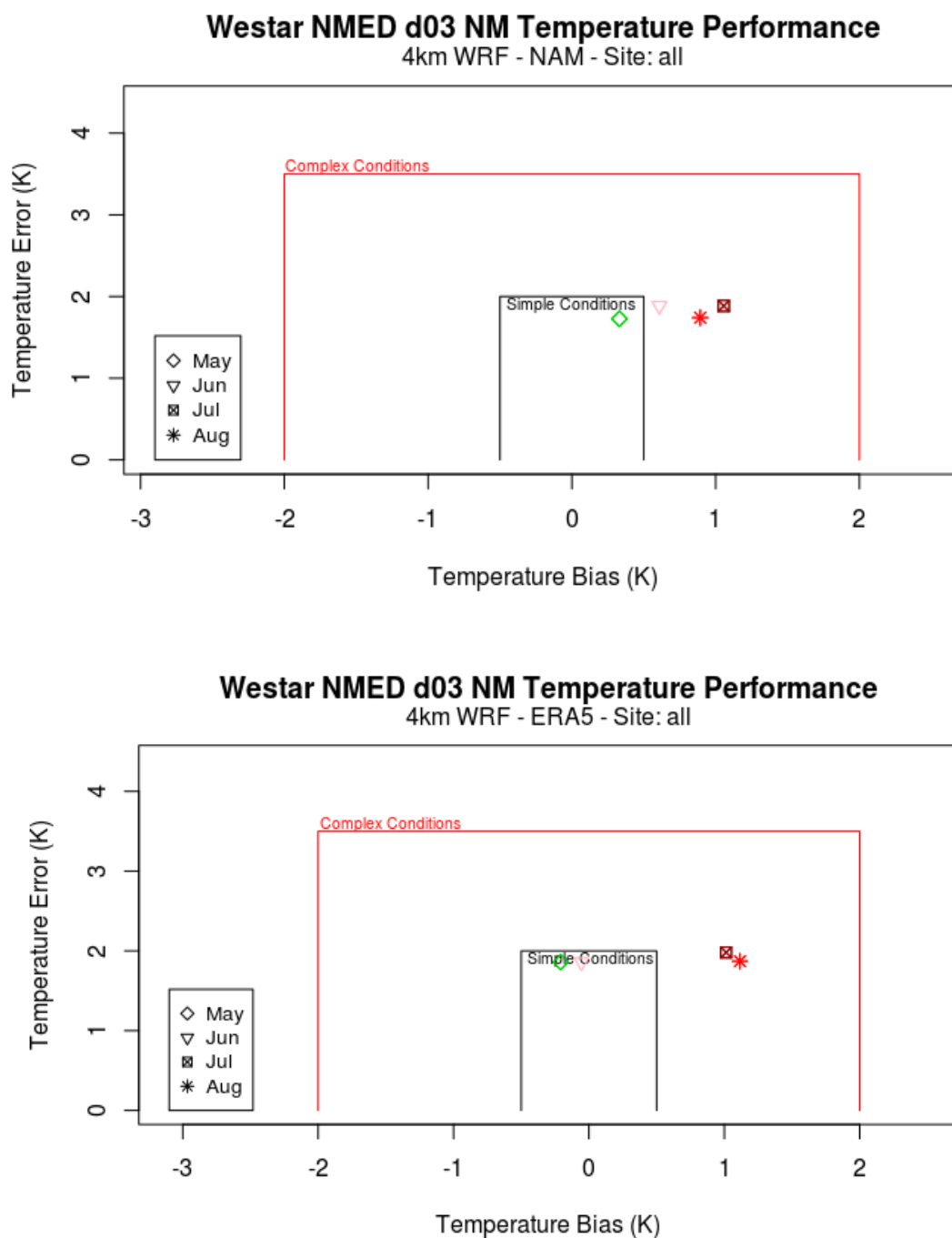


Figure 2-3. Soccer plot comparing WRF/NAM (top) and WRF/ERA5 (bottom) surface temperature (K) model performance against the Simple and Complex Benchmarks for monthly RMSE (y-axis) and Mean Bias (x-axis).

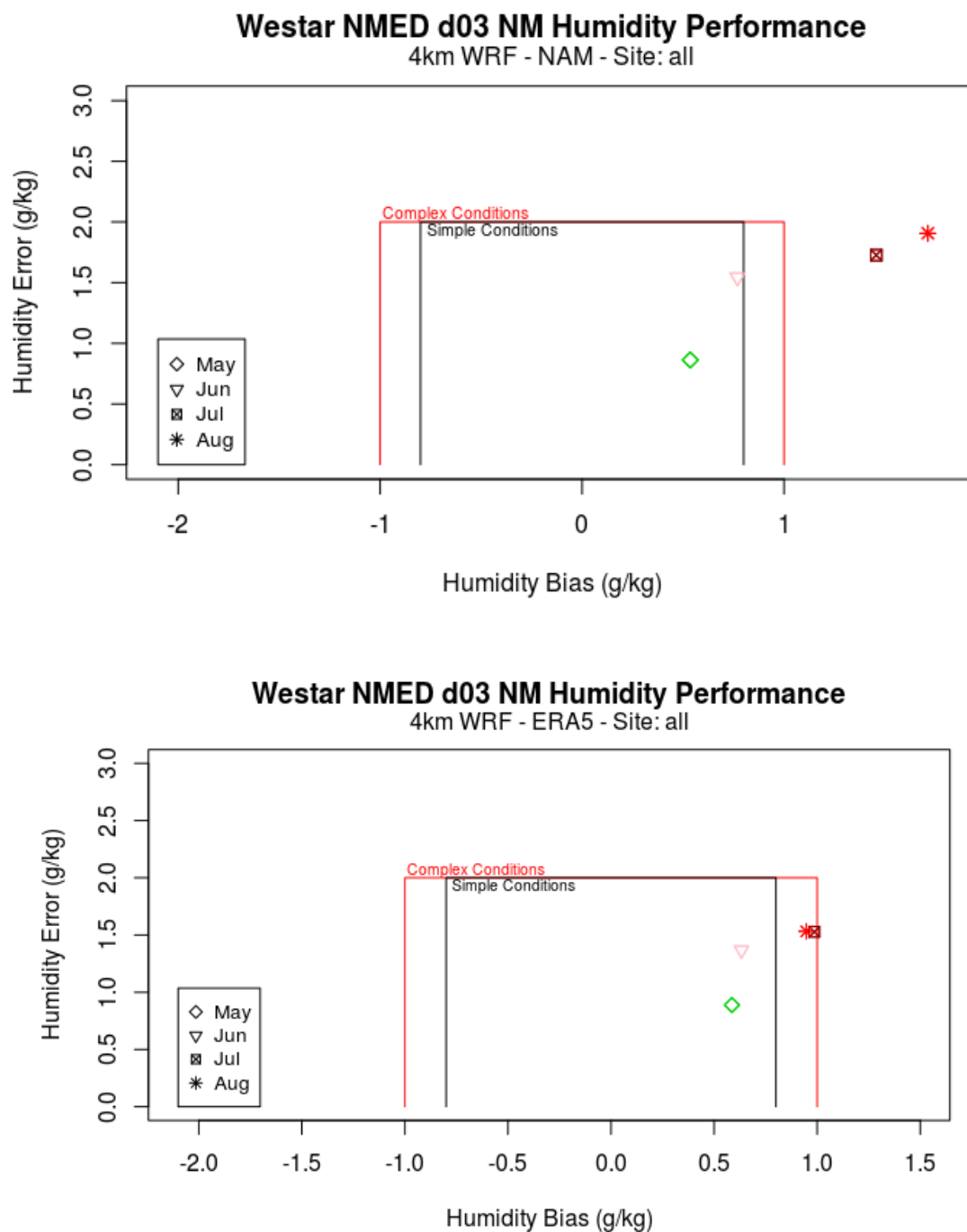


Figure 2-4. Soccer plot comparing WRF/NAM (top) and WRF/ERA5 (bottom) surface humidity (g/kg) model performance against the Simple and Complex Benchmarks for monthly RMSE (y-axis) and Mean Bias (x-axis).

2.4.2 Qualitative Evaluations for Precipitation Using PRISM Data

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 (PRISM¹⁸) is used to generate the precipitation analysis fields (Daly et al., 2008). The PRISM interpolation method of observed precipitation reflects, 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 stations entering the regression are assigned weights based primarily on the physiographic similarity of the station to the grid cell.

Figures 2-5 and 2-6 compares the PRISM monthly total precipitation across the 4-km New Mexico domain with the WRF/NAM and WRF/ERA5 model estimates for, respectively, July and August. Results for other months can be found in Ramboll and WESTAR (2020c). WRF/NAM overestimates the July monthly precipitation over northeast New Mexico, with WRF/ERA5 having an overestimation bias in most northerly Texas. But both WRF simulations have a dry bias for monthly precipitation over the remainder of New Mexico.

WRF/ERA5 does a better job at reproducing the locations and magnitudes of the August monthly PRISM precipitation than WRF/NAM (Figure 2-6). WRF/NAM overstates the August precipitation in central-south New Mexico.

¹⁸ <http://prism.oregonstate.edu/>

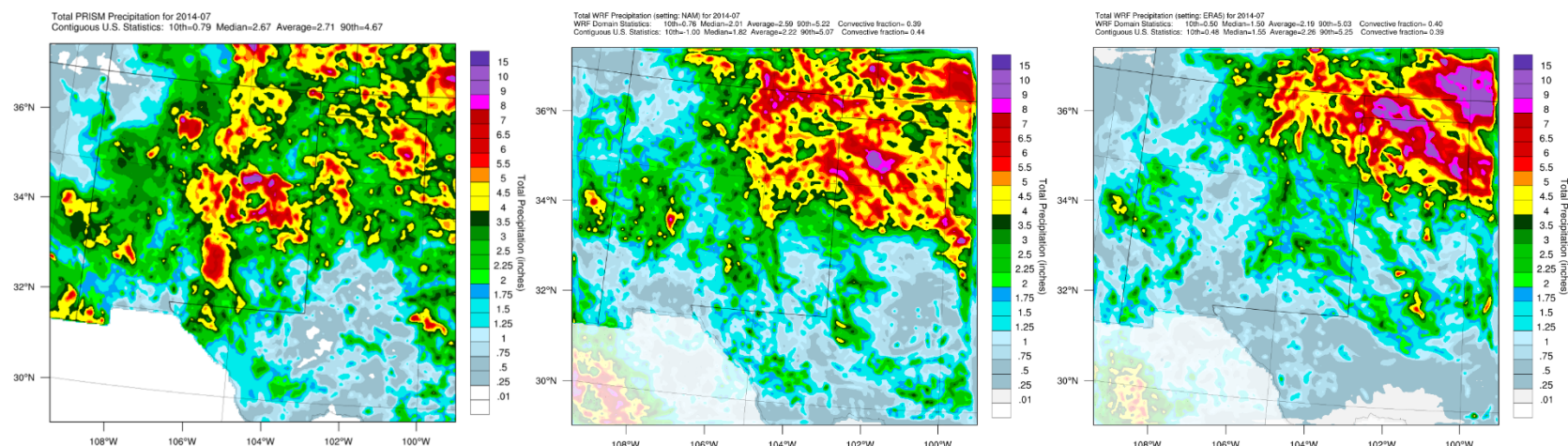


Figure 2-5. July monthly precipitation amounts from PRISM based on observations (left) and predicted by WRF/NAM (middle) and WRF/ERA5 (right).

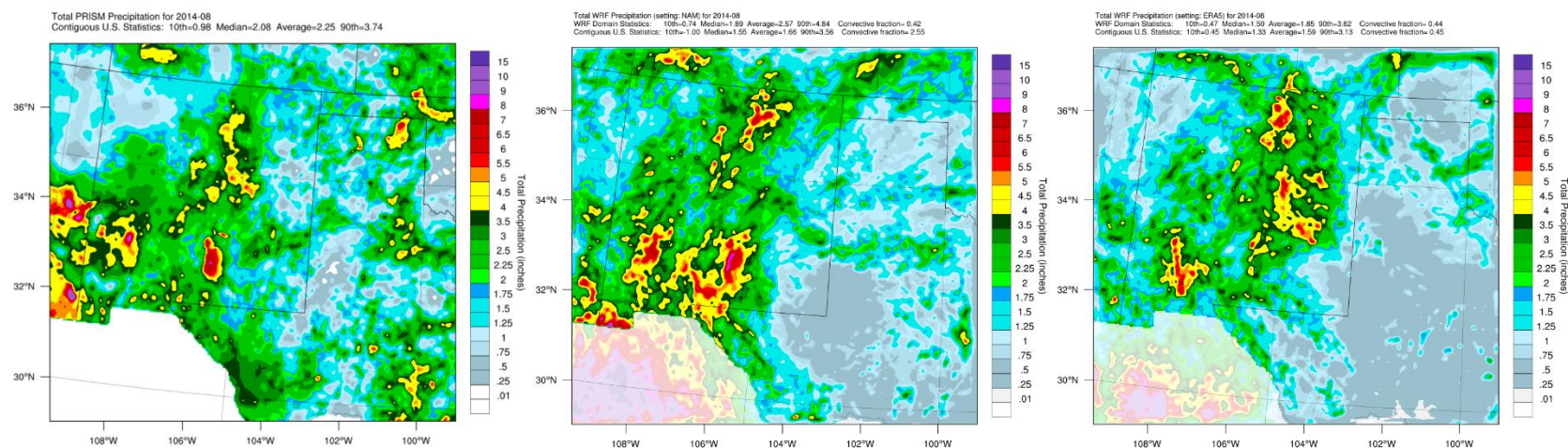


Figure 2-6. August monthly precipitation amounts from PRISM based on observations (left) and predicted by WRF/NAM (middle) and WRF/ERA5 (right).

2.4.3 Conclusions of 2014 WRF Model Performance

The model performance of the WRF/NAM and WRF/ERA5 simulations are reasonable and very similar for most meteorological variables (e.g., winds and temperature). This is in contrast to the WRAP-WAQS and EPA WRF 2014 simulations that had very different performance characteristics over New Mexico.¹⁹ The biggest difference in the performance of the two WRF simulations was for humidity and precipitation. The WRF/NAM simulation had a moist bias for June-August that is likely partly associated with overactive convective precipitation that was greater in WRF/NAM than WRF/ERA5. It is unclear whether the WRF/NAM overstated precipitation is due to overactive convective events when they occur, or having events occur when they are not observed.

From the meteorological model performance evaluation, it is not possible to determine which set of WRF meteorological inputs will produce better ozone model performance when used as meteorological inputs for CAMx. There are variations in spatial and temporal model performance that are difficult to estimate what effects they will have on ozone concentrations. Furthermore, there may be meteorological inputs (e.g., level of mixing) that are more important for ozone modeling than the parameters we have observed data to evaluate the meteorological model for (i.e., winds, temperature, humidity and precipitation). Although it appears that WRF/NAM overstates the monthly precipitation if that does not occur on high ozone days it may not matter to the ozone model performance.

CAMx was run for a portion of the summer of 2014 episode with meteorological inputs based on both the WRF/NAM and WRF/ERA5 simulations and the ozone estimates compared to determine which meteorological inputs performed best so were selected for use in the final CAMX 2014 36/12/4-km base case simulation. The meteorological diagnostic sensitivity tests using the CAMx photochemical model are described in Chapter 5.

¹⁹ https://www.wrapair2.org/pdf/NM_OAI_Study_Webinar1_2020-05-28.pdf

3. BOUNDARY CONDITION INPUTS

The Boundary Conditions (BCs) for the CAMx most outer 36-km 36US modeling domain lateral boundaries were based on output from a 2014 simulation of the GEOS-Chem global chemistry conducted by WRAP for their 2014v2 modeling platform.

3.1 WRAP 2014 GEOS-Chem Modeling

The WRAP-WAQS 2014v1 36/12-km CAMx and CMAQ base case simulations used BCs based on EPA's 2014 GEOS-Chem simulation that was used in EPA's 2014 modeling platform used in the 2014 National Air Toxics Assessment (NATA²⁰). The CAMx and CMAQ 2014v1 base case simulation and sensitivity modeling found that the BCs based on EPA's 2014 GEOS-Chem caused year-long ozone overestimation bias throughout the western U.S.²¹ Thus, WRAP conducted their own 2014 GEOS-Chem simulation using a newer version of the model and with updated emissions that resulted in much better CAMx ozone model performance without the systematic ozone over-prediction bias.²² Table 3-1 presents the WRAP 2014 GEOS-Chem model configuration.

Table 3-1. 2014 GEOS-Chem simulation model configuration used by WRAP whose output is used to define the 2014 day-specific diurnally varying BC inputs for the NM OAI Study photochemical modeling.

Science Options	WRAP 2014 GEOS-Chem Base Case
Version	Version 12.2.0 (release date: 2019-02-19)
Vertical Grid Mesh	72 Layers
Chemistry mechanism	GEOS-Chem standard chemistry with complex SOA option ²³ .
Horizontal Grids	2x2.5 degree (Nx, Ny = 144, 91)
Initial Conditions	6-month spin-up; starting from provided initial conditions for standard chemistry
Meteorology	2014 GEOS-FP meteorology
Photolysis mechanism	Default (FAST-J)
Advection Scheme	Default (TPCORE)
Cloud convection scheme	On / Relaxed Arakawa-Schubert
Planetary Boundary Layer mixing	On / non-local scheme implemented by Lin and McElroy
Dry deposition scheme	Default (Wesely)
Chemistry Solver	Default (FLEXCHEM)
Parallelization	Open Multi-Processing (OMP)

²⁰ <https://www.epa.gov/national-air-toxics-assessment>

²¹ http://views.cira.colostate.edu/iwdw/docs/waqs_2014v1_shakeout_study.aspx

²² https://www.wrapair2.org/pdf/WRAP_Shake-Out_Phase-III_Update_RTOWG_2019-09-10v3a.pptx

²³ We recommend turning off semivolatile primary organic aerosol (POA) chemistry and isoprene SOA reactions via the volatility-based scheme (VBS) [Pye et al., 2010] to avoid risk of double-counting in the complex SOA chemistry scheme. For more information, see <http://maraisresearchgroup.co.uk/Publications/GC-v11-02-SOA-options.pdf>

3.2 2014 GEOS-Chem Model Evaluation

The results of the WRAP 2014 GEOS-Chem simulation and CAMx sensitivity modeling using the new BCs can be found on the WAQS-WRAP2014v2 model evaluation webpage²⁴. Relevant for the NM OAI Study is the fact that this updated 2014 GEOS-Chem BCs do lead to better CAMx model performance for ozone concentrations and corrects a persistent year-long ozone overestimation bias that occurred using the previous 2014 GEOS-Chem simulation conducted by EPA and used in the EPA 2014 modeling platform. The NM OAI Study evaluated the use of the WRAP 2014 GEOS-Chem BCs for CAMx modeling at several sites in New Mexico and found good ozone performance that achieved ozone model performance goals.²⁵ Thus, the WAQS-WRAP 2014v2 BC inputs based on the WRAP 2014 GEOS-Chem simulation were used “as is” for the NM OAI Study.

²⁴ http://views.cira.colostate.edu/iwdw/docs/WRAP_WAQS_2014v2_MPE.aspx

²⁵ https://www.wrapair2.org/pdf/NM_OAI_Study_Webinar1_2020-05-28.pdf

4. 2014 AND 2028 EMISSION INPUTS

4.1 Summary of Emissions Used in 2014 and 2028 Modeling

The emissions inventories for the CAMx 2014 36/2/4-km base case modeling were based on the WRAP-WAQS 2014v2 emissions inventory. Within the 36-km 36US North American and 12-km 12WUS2 western U.S. domains, the WRAP-WAQS CAMx 2014v2 base case emission inputs were used without any changes.

For the 4-km New Mexico domain, the WRAP-WAQS 2014v2 emissions have been reviewed and updated as needed by the NMED. For on-road mobile sources, the 4-km domain emissions were based on MOVES2014 model, 2014 activity data and day-specific hourly gridded 2014 WRF 4-km meteorology run through SMOKE-MOVES.

For the NM OAI Study future year 2028 Base Case and 2028 New Mexico O&G Control Strategy, the emissions were based on the WRAP 2028OTBa2 emissions inventory with updated New Mexico O&G emissions and use of 2014 actual fires instead of the Representative Baseline fires. The 2028OTBa2 CAMx-ready emission inputs for the 36/12-km domains were used “as is”, substituting the 2014v2 actual 2014 fires for the Representative Baseline fires. For the 4-km NM domain, the 2028OTBa2 emissions were processed using SMOKE, with the new 2028 New Mexico (NM) oil and gas (O&G) emissions substituted for the NM O&G emissions used in the 2028OTBa2 emissions scenario.

The NM OAI Study 2028 O&G Control Strategy scenario used the exact same emissions as the NM OAI Study 2028 Base Case, only the controlled 2028 O&G emissions were used in New Mexico. The 2028 NM O&G Control Strategy oil and gas emissions were provided by ERG under separate contract to NMED.

4.2 Development of CAMx 2014 Base Case Emission Inputs

The CAMx 2014 base case emission inputs for the 36/12-km domains were based on the WRAP 2014v2 CAMx model-ready emission inputs and were used “as is.” For the 4-km NM domain, the New Mexico emissions from the 2014v2 database were reviewed and updated by the NMED. The 2014v2 emissions for New Mexico and portions of surrounding states within the 4-km New Mexico domain were then processed by the Sparse Matrix Operator Kernel Emissions (SMOKE) modeling system (UNC, 2015). SMOKE version 4.7 was used, which was released in October 2019.²⁶

4.2.1 Day-Specific On-Road Mobile Source Emissions

The 2014 on-road mobile source emission inputs for the 4-km New Mexico domain were generated using the SMOKE-MOVES emissions model. SMOKE-MOVES used a 2014 mobile source emission factor (EF) lookup table generated by the Motor Vehicle Emission Simulator (MOVES2014²⁷) model (EPA, 2014a,b,c). The SMOKE-MOVES default county-level 2014 vehicle activity data for New Mexico was reviewed by NMED and updated as needed. SMOKE-MOVES uses the 2014 MOVES EF lookup table, hourly gridded 4-km meteorological data from the 2014 WRF simulation conducted in this study (see Chapter 2) and 2014 county-level activity data (e.g., vehicle miles travelled

²⁶ <https://www.cmascenter.org/smoke/>

²⁷ <https://www.epa.gov/moves/moves-onroad-technical-reports#moves2014>

[VMT], speed, etc.) to generate 2014 day-specific hourly gridded on-road mobile source emission inputs for CAMx and the 4-km New Mexico domain.

4.2.2 Point Source Emissions

2014 point source emissions were based on the WRAP-WAQS 2014v2 emissions inventory. The 2014v2 New Mexico point source emissions were reviewed and updated by NMED. Point sources were processed in two streams: (1) major point sources with Continuous Emissions Monitoring (CEM) devices, which are primarily fossil-fueled Electrical Generating Units (EGU) with capacity of 25 MW or greater; and (2) point sources without CEMs. For point sources with CEM data, day-specific hourly NO_x and SO₂ emissions were used for the 2014 base case emissions scenario. The VOC, CO, and PM emissions for point sources with CEM data were based on the annual emissions data in the 2014v2 inventory temporally allocated to each hour of the year using the CEM hourly heat input.

4.2.3 Area and Non-Road Source Emissions

The 2014 area and non-road sources were spatially allocated to the 4-km New Mexico grid using an appropriate surrogate distribution (e.g., population for home heating, etc.). The area sources were temporally allocated by month and by hour of day using the SMOKE source-specific temporal allocation factors, while chemical speciation used the SMOKE source-specific CB6r4 speciation allocation profiles.

4.2.4 Episodic Biogenic Emissions

Two different CAMx 2014 base case simulations were conducted using two different biogenic emission inputs within the 4-km NM domain. The first CAMx 2014 base case 4-km domain biogenic emissions were generated using Version 3.1 of the MEGAN biogenic emissions model. MEGAN v3.1 is a new version of MEGAN and comes with a Leaf Area Index (LAI) database that defines the vegetative biomass and type that when combined with temperature and light dependent emission factors produces biogenic VOC emissions using the day-specific hourly gridded WRF meteorology. However, the new LAI data in MEGAN v3.1 were missing for urban areas producing “holes” in the biogenic VOC emission inputs. Thus, revised CAMx 2014v2 base case 4-km NM biogenic emission inputs used the BEIS v3.7 biogenic emissions model. BEIS3.7 is the most recent version of BEIS released by EPA in October 2020. BEIS3.7 uses updated biomass and emissions factors, and the Biogenic Emissions Landcover Database version 5 (BELD5). Table 4-1 compares the biogenic NO_x and VOC emissions by month (in tons/month) for the 4-km NM domain and the two biogenic models. The BEIS NO_x emissions are substantially lower than MEGAN, and VOC emissions are mostly lower except early summer month showing slightly higher emissions with BEIS. Figure 4-1 displays the spatial distributions of emissions in the 4-km NM domain expressed as episode average tons per day. The BEIS NO_x and VOC emissions are mostly lower than MEGAN throughout the domain. The missing biogenic VOC emissions in urban areas (e.g., El Paso/Juarez) using MEGAN v3.1 is also evident in the spatial maps.

Table 4-1. 2014 biogenic emissions (tons/month) in the 4-km NM domain estimated by MEGAN3.1 and BEIS3.7.

Tons/month		MEGAN	BEIS	% Diff (BEIS-MEGAN)
NO_x	May	35,050	10,602	-69.8%
	Jun	42,445	13,134	-69.1%
	Jul	51,639	12,838	-75.1%
	Aug	41,002	11,923	-70.9%
VOC	May	128,323	159,809	24.5%
	Jun	267,055	256,379	-4.0%
	Jul	317,697	251,562	-20.8%
	Aug	354,570	216,032	-39.1%

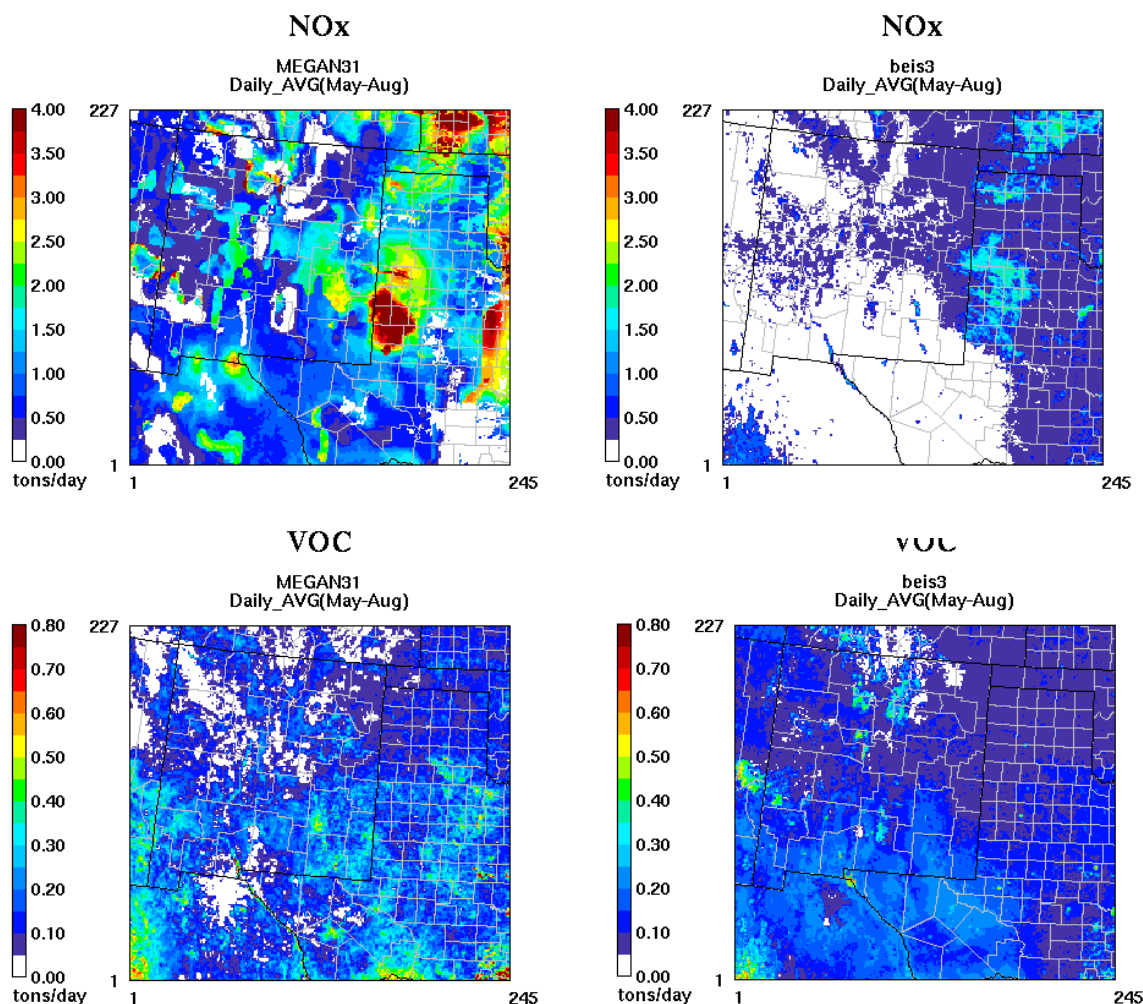


Figure 4-1. Spatial distribution of NO_x (top panel) and VOC (bottom panel) biogenic emissions (episode average tons per day) in the 4-km NM domain estimated by MEGAN3.1 (left) and BEIS3.7 (right).

4.2.5 Wildfires, Prescribed Burns, Agricultural Burns

2014 emissions from open-land burning including wildfires, wildland prescribed burns and agricultural burning were based on the WRAP-WAQS 2014v2 emissions inventory. The WRAP Fire and Smoke Work Group (FSWG²⁸) processed the 2014NEIv2 Bluesky/SMARTFIRE fire emissions for the U.S. and classified them as either wildfires (WF), wildland prescribed burns (Rx) or agricultural burning (Ag) and made other updates for the 2014v2 inventory. The 2014NEIv2 fire emissions for Mexico and Canada were used without any changes. Table 4-2 displays NO_x and VOC emissions by month and fire type within the 4-km NM domain. Figure 4-2 displays spatial maps of NO_x emissions from 2014 summer fires for the 4-km NM domain. Emissions are expressed as episode average tons per day per grid cell. We see some hotspots on the wildfires plot in New Mexico and Arizona near the western boundary of the 4-km domain.

²⁸ <https://www.wrapair2.org/FSWG.aspx>

Table 4-2. 2014 fire emissions summary (tons/month) by fire type for the 4-km NM domain

Tons/month	Pollutant	Ag fires	Prescribed fires	Wildfires	Mexico fires
NO _x	May	36	90	597	49
	Jun	11	81	1,056	32
	Jul	18	13	332	8
	Aug	18	69	39	2
VOC	May	60	617	6,663	92
	Jun	18	736	17,641	187
	Jul	29	82	4,985	40
	Aug	28	1,376	371	13

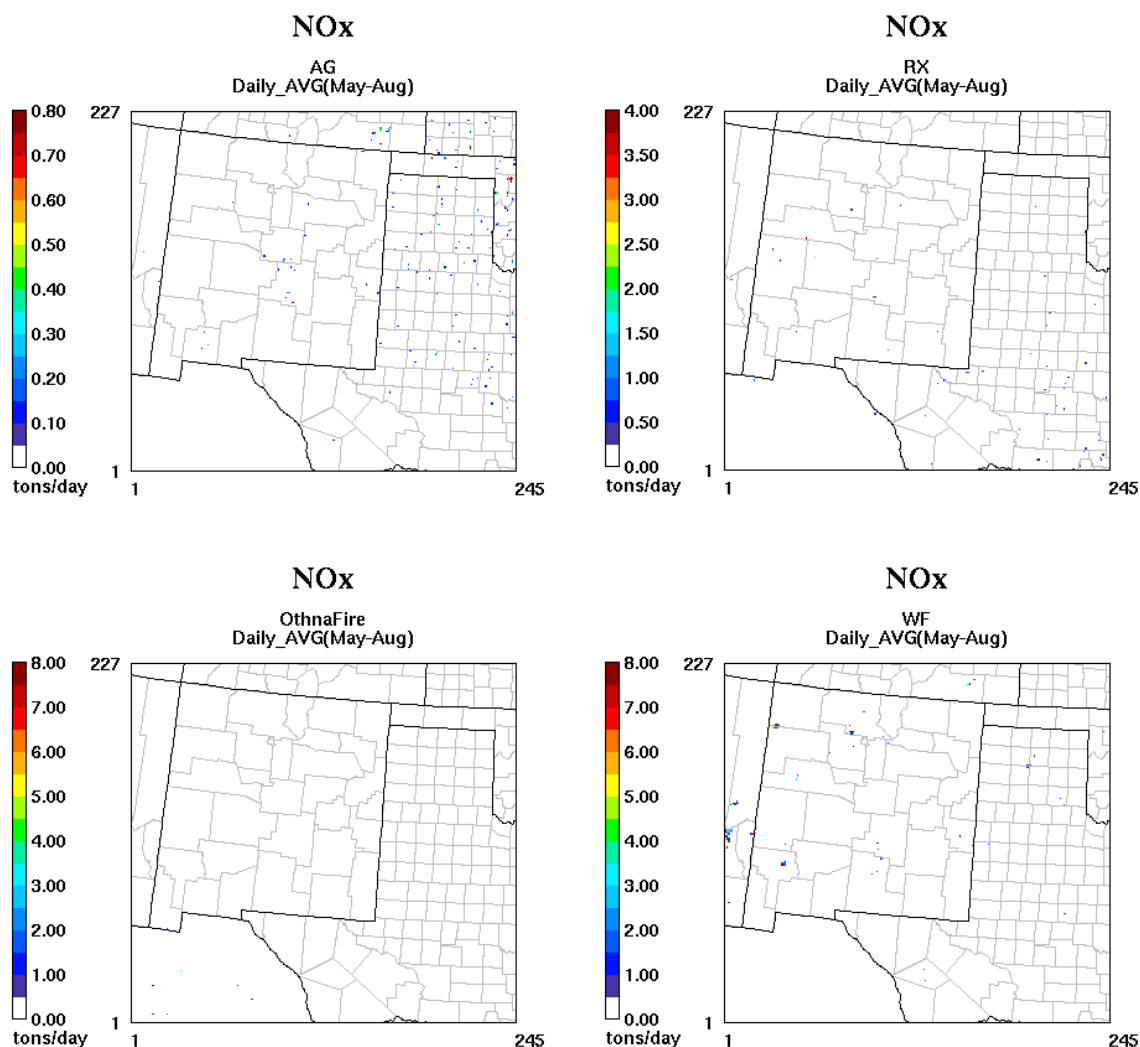


Figure 4-2. Spatial distribution of agricultural fires, prescribed fires, wildfires and Mexico fires (clockwise starting from top left) NO_x emissions (episode avg tons per day) for New Mexico 4-km domain.

4.2.6 Other Natural Emissions

Lightning NO_x (LNO_x), and windblown dust (WBD) emissions were generated for the 4-km domain using special CAMx processors and WRF 2014 meteorological data. Oceanic emissions such as sea salt spray aerosol (SSA) and dimethyl sulphide (DMS) were not generated for the 4-km New Mexico domain since this domain does not include any ocean within it. However, the LNO_x, WBD and oceanic emissions for the 36-km and 12km were based on the WRAP-WAQS 2014v2 emissions and were included in the modeling.

4.2.7 2014 Emission Results

Table 4-3 summarizes the 2014 criteria air pollutant emissions in episode average short tons per day by source category for the 4-km New Mexico domain. These data represent the model-ready emissions input to the CAMx air quality model for the 2014

base case. Mostly, emissions are summarized from the SMOKE reports generated by the SMKMRG program. There are a couple of exceptions to this general approach, fugitive dust and EGU sources. The fugitive dust emissions were adjusted after SMOKE processing to account for fugitive dust correction factors that are derived from the Biogenic Emission Landuse Database version 4 (BELD4). The correction factors are necessary to account for dust removal due to local vegetation scavenging so are not transported downwind. Model-ready emissions for EGU and Mexico point sources were obtained from WRAP/WAQS 2014 platform so were summarized for the 4-km domain outside of SMOKE.

Table 4-3. 2014 base case anthropogenic emissions summary (episode average short tons per day) by source category for the 4-km New Mexico domain.

Country/ Category	Source Category	CO	NH ₃	NO _x	PM _{2.5}	PM ₁₀	SO ₂	VOC
US Anthro	Area fugitive dust	0.0	0.0	0.0	253.3	1,788.2	0.0	0.0
	Agricultural ammonia sources	0.0	764.7	0.0	0.0	0.0	0.0	43.4
	Non-point Oil and Gas for 7 WRAP States (CO, MT, NM, ND, SD, UT, WY)	237.7	0.0	157.8	4.4	4.4	11.3	567.3
	Remaining Non-point Oil and Gas	286.8	0.0	311.7	6.9	6.9	30.0	1,642.5
	Residential Wood Combustion	7.0	0.1	0.1	0.5	0.5	0.0	1.2
	Other nonpoint sources	141.3	1.5	28.5	9.3	13.4	4.5	213.2
	On-road mobile	1,476.2	6.0	444.5	13.2	20.1	1.7	150.6
	Locomotive	22.9	0.1	122.7	2.9	3.1	0.1	6.2
	Non-road mobile	570.3	0.2	133.4	9.0	9.4	0.3	73.2
	EGU point sources	89.2	3.4	210.6	12.9	17.8	160.0	5.0
	Point Oil and Gas for 7 WRAP States (CO, MT, NM, ND, SD, UT, WY)	89.9	0.0	114.7	1.4	1.4	23.8	56.1
	Remaining Point Oil and Gas	113.8	0.1	205.2	3.2	3.3	27.1	48.4
	Non-EGU point sources	74.4	4.9	47.5	11.4	32.5	49.3	24.4
Mexico Anthro	Mexico area	19.9	33.2	42.2	5.8	15.7	1.7	103.3
	Mexico on-road mobile	356.3	0.6	98.4	1.5	2.6	1.4	34.4
	Mexico point sources	28.4	0.7	20.2	4.8	5.7	16.4	8.3

Figure 4-3 presents pie charts showing VOCs and NO_x emissions from anthropogenic sources by source category for New Mexico and portion of surrounding states within the 4-km domain. Point and non-point oil and gas sectors account for majority of NO_x emissions followed by on-road mobile and EGU sources. In New Mexico, oil and gas sources are the largest anthropogenic VOC emitters and accounts for nearly 80% of 4-km domain VOC emissions.

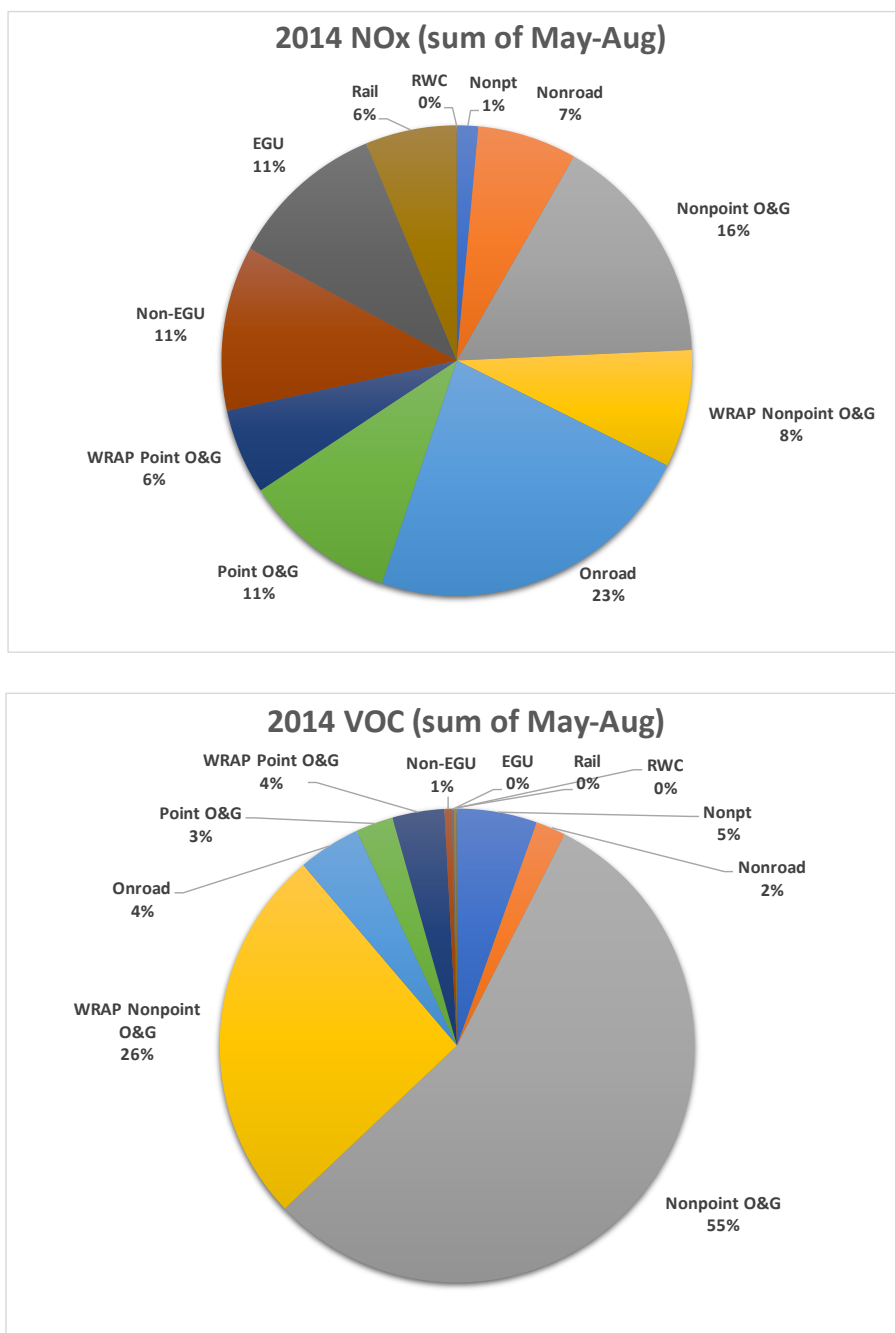


Figure 4-3. New Mexico 2014 base case anthropogenic NO_x and VOC emissions by source category.

Figure 4-4 displays spatial maps of NO_x and VOC anthropogenic emissions from the oil and gas sector across the 4-km New Mexico domain. Top panel shows emission maps for non-point O&G sources while bottom panel shows point O&G sources. The San Juan and Permian basins are clearly visible on the emissions map and confirm correct spatial allocation of oil and gas emissions. Figure 4-5 shows emission maps for on-road mobile (top panel), rail (middle panel) and non-point sources including non-road equipment (bottom panel).

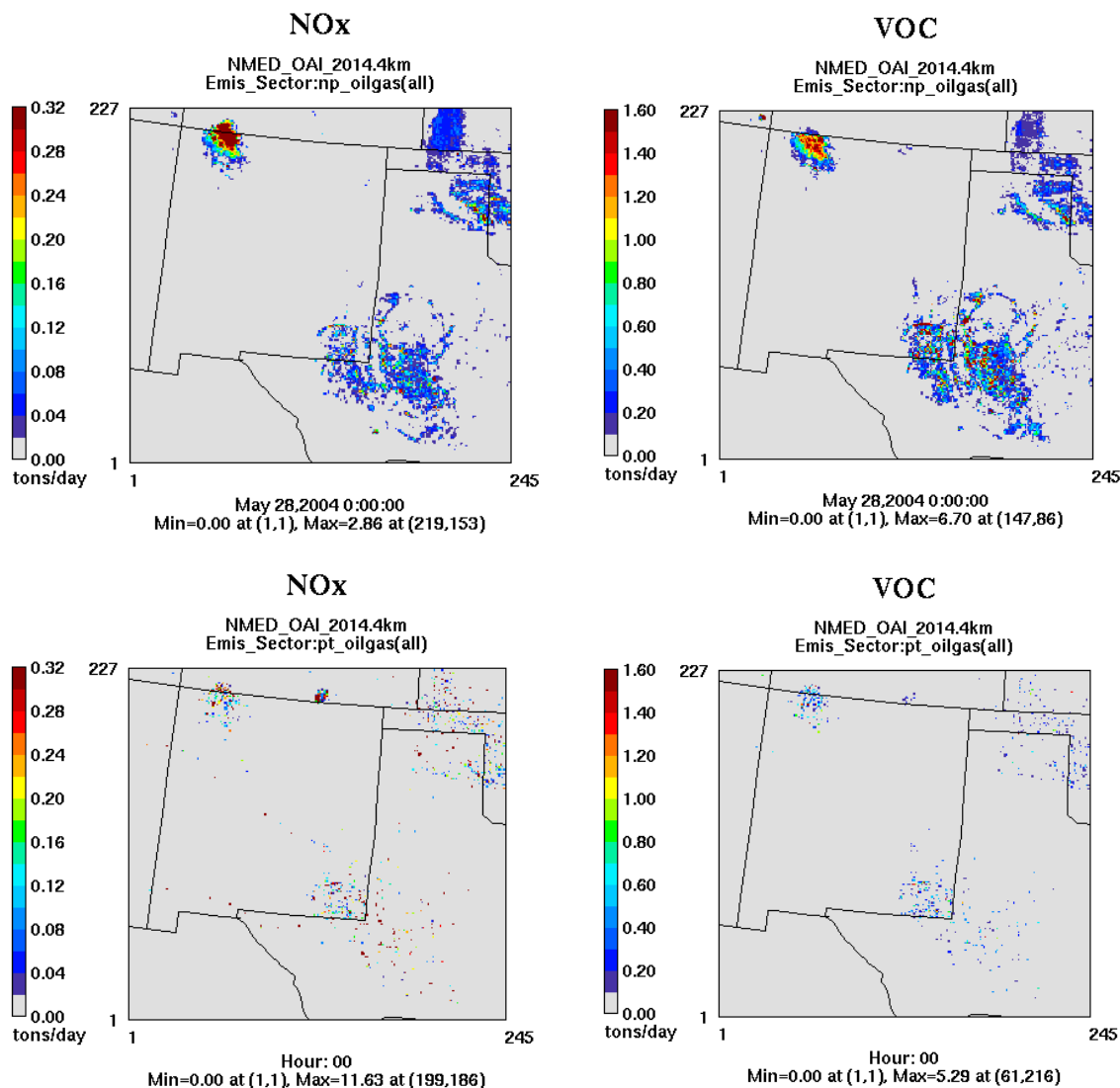


Figure 4-4. Spatial distribution of the non-point (top) and point (bottom) source oil and gas NO_x (left) and VOC (right) emissions (episode avg tons per day) for New Mexico 4-km domain.

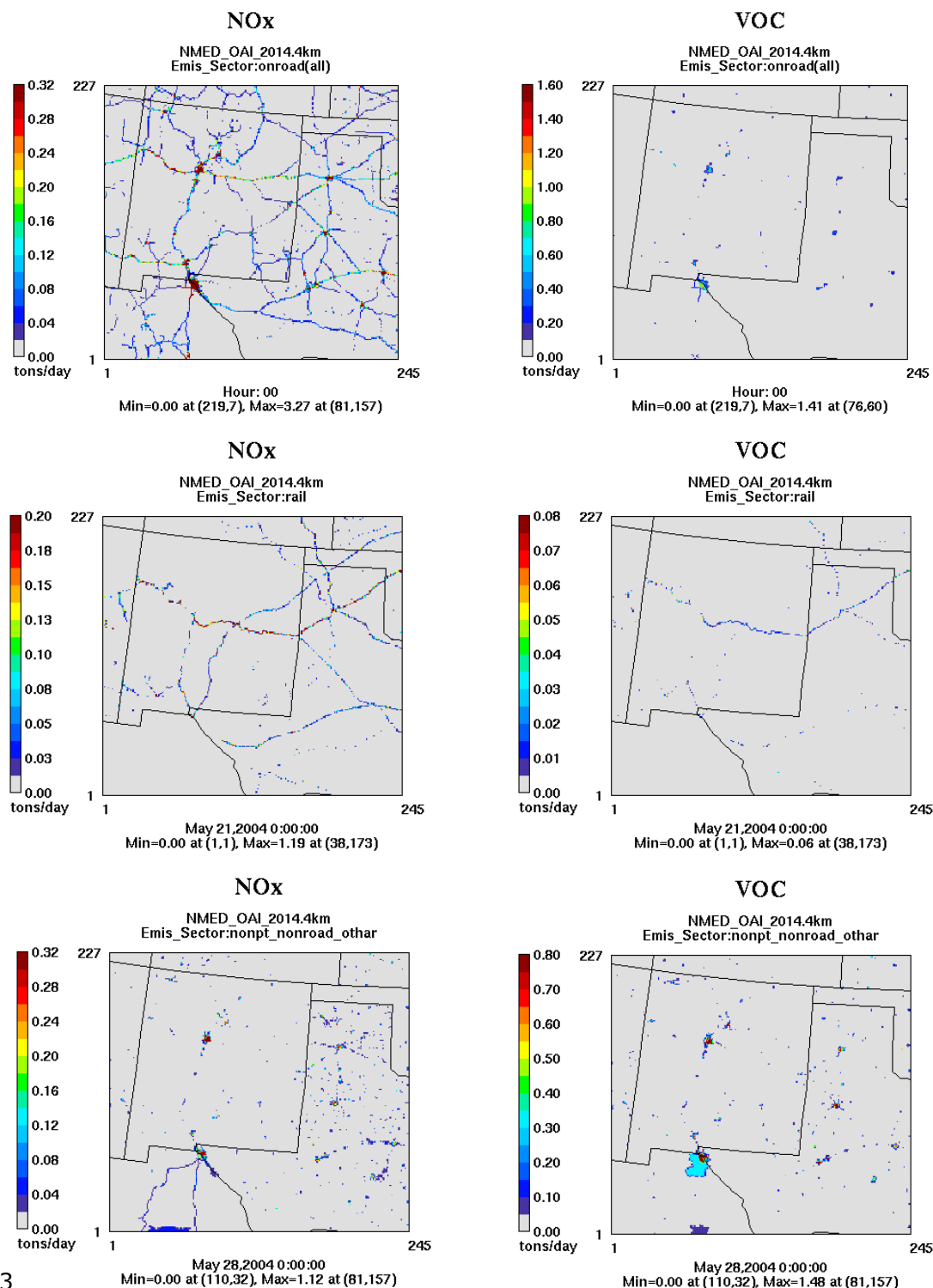


Figure 4-5. Spatial distribution of on-road (top), rail (middle) and non-point/non-road equipment (bottom) NO_x (left) and VOC (right) emissions (episode avg tons per day) for New Mexico 4-km domain.

4.3 Development of CAMx 2028 Emission Scenarios

The NM OAI Study 2028 base case and 2028 O&G Control Strategy emissions were based on the WRAP 2028OTBa2 emissions inventory with updates to NM O&G emissions and using 2014 actual fires. Details on the 2028OTBa2 emission assumptions are contained in the WRAP Representative Baseline (RepBase2) and 2028 On-the-Books (2028OTBa2) CAMx Simulation Run Specification Sheet.²⁹ The original WRAP 2028OTBa2 emissions scenario used EPA's 2028 emission projections from their 2016v1 modeling platform³⁰ for several source sectors (e.g., non-EGU Point Sources). However, some of EPA's 2028 emission projections were inconsistent with the WRAP 2014v2 emission updates for the western states and there were double counted sources in EPA's 2016v1 platform 2028 emission projections. Thus, WRAP elected to use more source sector emissions from the EPA 2016v1 and WRAP 2014v2 emissions inventories that were vetted by many states resulting in the following source sectors used in the 2028OTBa2 emissions inventory with deviations from the WRAP 2028OTBa2 from the NM OAI Study 2028 base case discussed below (see details in Run Specification Sheet cited in footnote):

- The California Air Resources Board provided 2028 emissions for California and all source sectors.
- 2028 emissions for Electrical Generating Units (EGU) for fossil-fueled EGUs in WRAP states were reviewed in detail by the individual states starting from the results of the WRAP EGU Analysis Project.³¹ 2028 emissions for Non-fossil-fueled EGU in the WRAP region and all EGUs outside of the WRAP region were based on EPA's 2016v1 modeling platform 2028 projections.
- 2028 O&G emissions for New Mexico were based on new estimates developed in the NM OAI Study as described later in this chapter. 2028 O&G emissions for other non-New Mexico WRAP region O&G basins are based on the WRAP projections out to 2023 (Ramboll, 2020a). The EPA 2016v1 platform 2016 O&G emissions were used for non-WRAP states. The 2028OTBa2 O&G emissions were reviewed in detail by WRAP region states to eliminate duplications and update sources as needed.
- Non-EGU Point Source emissions for the WRAP states were reviewed in detail by the individual states starting from the WRAP 2014v2 emissions, while the EPA 2016v1 platform emissions for 2016 were used for non-WRAP states.
- The SMOKE-MOVES model with 2014 meteorology, 2028 vehicle activity and 2028 MOVES2014 Emissions Factor Look-Up tables were used to generate 2028 on-road mobile source emissions by either WRAP³² for the 12-km domain or the NM OAI Study for the 4-km domain.
- 2028 Non-road emissions were based on 2028 estimates by WRAP in the Mobile Source Emissions Inventory Projection Project for the WRAP region and EPA's 2028 estimates for the non-WRAP states.

²⁹

https://views.cira.colostate.edu/docs/iwdw/platformdocs/WRAP_2014/EmissionsSpecifications_WRAP_RepBase2_and_2028_OTBa2_RegionalHazeModelingScenarios_Sept30_2020.pdf

³⁰ <https://www.epa.gov/air-emissions-modeling/2016v1-platform>

³¹ <https://www.wrapair2.org/EGU.aspx>

³² WRAP Mobile Source Emissions Inventory Projections Project

- WRAP region 2014v2 and EPA 2016v1 emissions were used for the Non-Point source sector in the 2028OTBa2 emissions scenario.
- The NM OAI Study 2028 fires were based on the WRAP region 2014v2 actual fire estimates.
- Natural emissions (biogenic, lighting NO_x, windblown dust and oceanic) were the same as used in the WRAP 2014v2, RepBase2 and 2028OTBa2 emission scenarios

4.3.1 2028 Base Case New Mexico Oil and Gas Emissions

A circa 2028 forecast oil and gas (O&G) emission inventory was developed for New Mexico for use in the NM OAI Study 2028 Base Case emission scenario. The basis of the forecast O&G emission inventory is circa 2028 O&G activity estimates provided by BLM³³ and emissions and emission per unit of O&G activity from the future year WRAP Oil and Gas Working Group (OGWG) emission inventory (Ramboll, 2020a). The WRAP OGWG developed 2023 future year O&G emissions for 7 of the WRAP states.

The 2028 New Mexico O&G emission inventory includes wellsite, gathering, and processing subsectors, which are items 1, 5, and 6 in Figure 4-6. Item 1 are On-Shore Petroleum and Natural Gas Production is referred to as “wellsite” sources; emissions from wellsite sources are classified as nonpoint sources. Item 2 are Gathering and Boosting sources. Item 6 consists of Gas Processing Plants are collectively referred to as “midstream” sources; emissions from midstream sources are classified as point sources. The classification of well-site emissions as nonpoint and midstream emissions as point sources is consistent with other O&G emission inventory classifications used in prior studies, such as the BLM Colorado Air Resource Management Modeling Study (CARMMS)³⁴.

³³ Email communication from BLM Staff (Forrest Cook) to Ramboll (John Grant). September 15, 2020.

³⁴ <https://www.blm.gov/programs/natural-resources/soil-air-water/air/colorado>

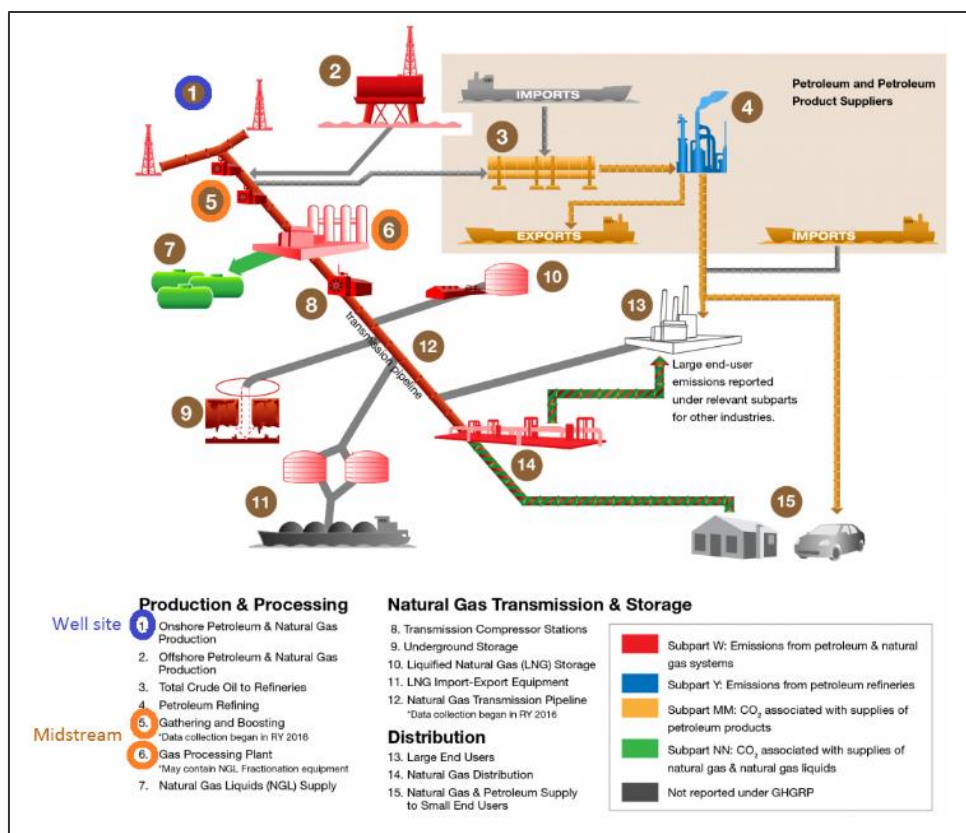


Figure 4-6. Example Petroleum and Natural Gas Industry schematic³⁵.

The BLM O&G forecast factors were used to project New Mexico O&G emissions to 2028. Table 4-4 compares the New Mexico O&G VOC and NO_x activity for the WRAP 2014 and 2023 scenarios with the NM OAI Study 2028 base case activity based on BLM forecasts. With the exception of spud count, the 2028 NM O&G activity is greater than 2014.

A comparison of the WRAP OGWG 2014 and 2023 New Mexico O&G emissions with the 2028 values from the NM OAI Study are given in Table 4-5. Across New Mexico, 2028 O&G NO_x and VOC emissions are, respectively, 29% and 15% higher than in 2014. In the Permian Basin, New Mexico 2028 O&G NO_x emissions are 64% higher than 2014, with VOC emissions 19% higher. The 2028 and 2014 New Mexico O&G emissions in the San Juan Basin are more comparable, with 2028 NO_x and VOC emissions, respectively, 1% and 10% higher than 2014.

³⁵ Source: <https://www.epa.gov/ghgreporting/ghgrp-and-oil-and-gas-industry>, accessed in April 2020.

Table 4-4. Comparison of WRAP OGWG 2014 and 2023 New Mexico O&G emissions used in the 2014v2 and 2028OTBa2 scenarios with the NM OAI study 2028 base case New Mexico O&G emissions based on BLM forecast.

Activity Metric	WRAP OGWG		BLM Forecast
	2014	2023	Circa- 2028
Permian Basin (NM)			
Oil Production (million bbl)	119	276	166
Gas Production (BCF)	508	1,190	790
Well Count	28,615	27,335	40,478
Spud Count	1,178	651	794
San Juan Basin (NM)			
Oil Production (million bbl)	6	7	7
Gas Production (BCF)	713	440	1,138
Well Count	21,687	19,604	23,073
Spud Count	146	64	94
Las Vegas-Raton Basin (NM)			
Oil Production (million bbl)	0	0	0
Gas Production (BCF)	24	24	20
Well Count	835	835	835
Spud Count	0	0	0
Sierra Grande Uplift (NM)			
Oil Production (million bbl)	0	0	0
Gas Production (BCF)	0.02	0.02	0.27
Well Count	1	1	8
Spud Count	34	34	0.4

Table 4-5. Comparison of WRAP OGWG 2014 and 2023 NO_x and VOC New Mexico O&G emissions with the NM OAI Study 2028 base case.

Pollutant	WRAP OGWG		NMED OAI EI
	2014	2023	2028
New Mexico State Total			
NO _x	81,188	93,719	104,955
VOC	185,269	226,032	213,073
Permian , NM			
NO _x	35,251	52,074	57,922
VOC	97,977	149,609	116,896
San Juan , NM			
NO _x	44,730	39,789	45,200
VOC	86,567	75,670	95,500
Estancia Basin , NM			
NO _x	113	645	645
VOC	5	26	26
Orogrande Basin , NM			
NO _x	541	548	548
VOC	28	30	29
Raton , NM			
NO _x	8	8	6
VOC	646	646	600
Pedregosa Basin , NM			
NO _x	262	373	373
VOC	6	9	9
Basin-And-Range Province , NM			
NO _x	261	261	261
VOC	10	11	11
Sierra Grande Uplift , NM			
NO _x	23	23	0
VOC	31	31	2

4.4 Summary of 2014 and 2028 Base Case Emissions

Tables 4-6 through 4-8 summarizes the total emissions in New Mexico for the 2014 and 2028 base case emission scenarios and their differences. Graphical comparisons of the changes in NO_x and VOC emissions between 2014 and 2028 base cases are shown in, respectively, Figures 4-7 and 4-8. And the distribution of NO_x and VOC emissions across source sectors are shown in Figures 4-9 and 4-10, respectively. Total NO_x emissions in New Mexico are estimated to be reduced by -28% between 2014 and 2028 with the largest reductions coming from on-road mobile (-72%), EGU point (-69%) and non-road mobile (-51%) source sectors (Table 4-6 and Figure 4-7). These NO_x emission reductions were offset somewhat by increases in O&G point (+40%) and non-point (+36%) source sectors. Although there are large reductions in on-road (-61%) and non-road (-49%) mobile source VOC emissions between 2014 and 2028 base cases, the total reduction in New Mexico VOC emissions between 2014 and 2028 is only -6% because non-point O&G dominates (~75%; Figure 4-10) anthropogenic VOC emissions in New Mexico and they are only reduced by -5%.

Table 4-6. Summary of total emissions (tons/year) in New Mexico for the 2014 base case emissions scenario.

Category	CO	NH ₃	NO _x	PM _{2.5}	PMC	SO ₂	VOC
Fugitive Dust	0	0	0	31,152	188,801	0	0
Agricultural	0	28,774	0	0	0	0	2,825
Non-Point	23,039	262	5,934	1,561	794	937	28,621
Non-Road	77,821	13	7,334	548	40	18	9,397
O&G Non-Point	76,949	0	45,476	1,362	0	4,129	321,608
On-Road	246,144	939	75,861	2,194	1,042	252	26,275
O&G Point	23,458	0	31,125	436	0	8,623	40,744
EGU Point	11,309	422	43,071	1,507	650	11,911	429
Non-EGU Point	5,479	54	3,829	592	1,577	308	2,043
Rail	3,527	11	20,114	490	52	12	1,033
RWC	1,375	10	23	93	0	4	214
Total	469,102	30,485	232,766	39,935	192,956	26,194	433,188

Table 4-7. Summary of total emissions (tons/year) in New Mexico for the 2028 base case emissions scenario.

Category	CO	NH ₃	NO _x	PM _{2.5}	PMC	SO ₂	VOC
Fugitive Dust	0	0	0	31,152	188,801	0	0
Agricultural	0	28,774	0	0	0	0	2,825
Non-Point	23,039	262	5,934	1,561	794	937	28,621
Non-Road	69,460	15	3,618	244	24	11	4,767
O&G Non-Point	106,267	0	61,987	1,989	0	21,789	304,635
On-Road	111,251	821	21,610	688	1,178	143	10,311
O&G Point	37,205	0	43,480	706	55	11,912	53,212
EGU Point	7,173	301	13,389	1,292	755	3,385	256
Non-EGU Point	5,479	54	4,126	592	1,577	639	2,043
Rail	3,845	12	14,493	300	11	14	603
RWC	1,375	10	23	93	0	4	214
Total	365,093	30,248	168,661	38,617	193,195	38,834	407,488

Table 4-8. Percent differences in total New Mexico emissions between the 2014 and 2028 emission scenarios.

Category	CO	NH ₃	NO _x	PM _{2.5}	PMC	SO ₂	VOC
Fugitive Dust				0%	0%		
Agricultural		0%					0%
Non-Point	0%	0%	0%	0%	0%	0%	0%
Non-Road	-11%	17%	-51%	-56%	-41%	-37%	-49%
O&G Non-Point	38%		36%	46%	-98%	428%	-5%
On-Road	-55%	-13%	-72%	-69%	13%	-43%	-61%
O&G Point	59%		40%	62%		38%	31%
EGU Point	-37%	-29%	-69%	-14%	16%	-72%	-40%
Non-EGU Point	0%	0%	8%	0%	0%	107%	0%
Rail	9%	9%	-28%	-39%	-78%	9%	-42%
RWC	0%	0%	0%	0%	0%	0%	0%
Total	-22%	-1%	-28%	-3%	0%	48%	-6%

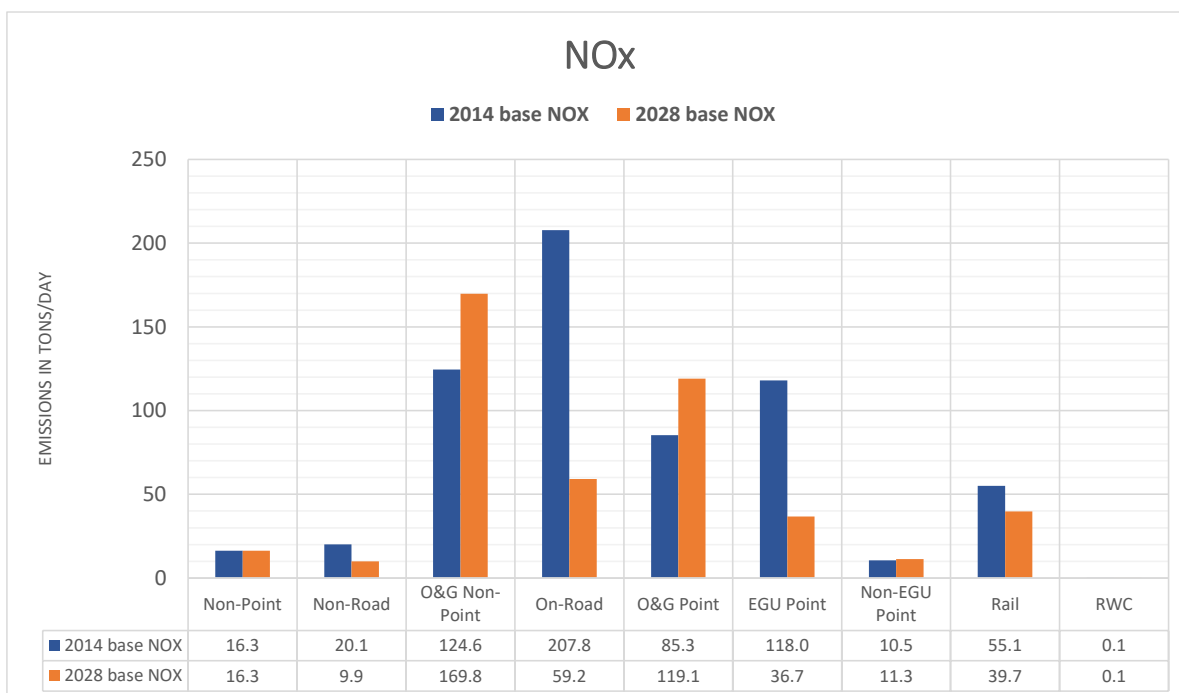


Figure 4-7. Comparison of 2014 and 2028 New Mexico NO_x emissions by source sector.

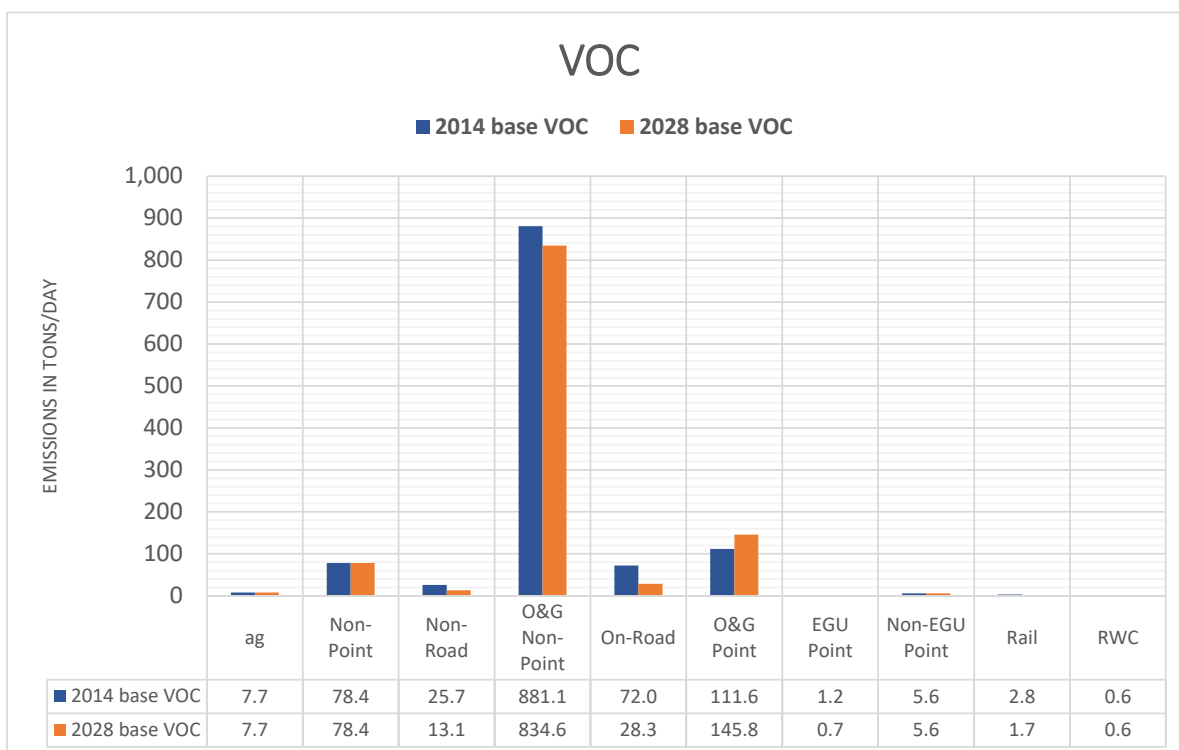


Figure 4-8. Comparison of 2014 and 2028 New Mexico NO_x emissions by source sector.

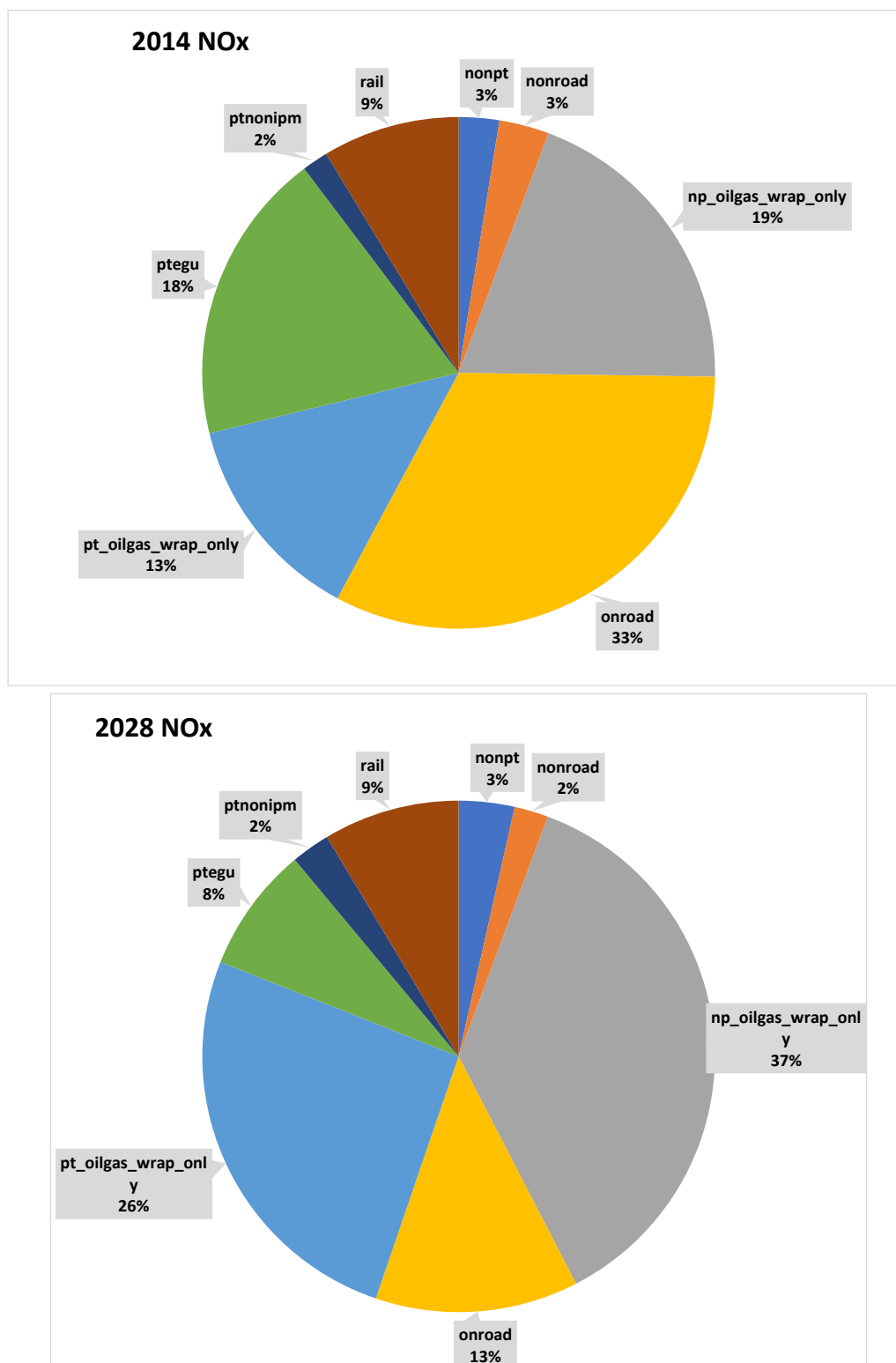


Figure 4-9. Distribution of New Mexico NO_x emissions across source sectors for the 2014 (top) and 2028 (bottom) base cases.

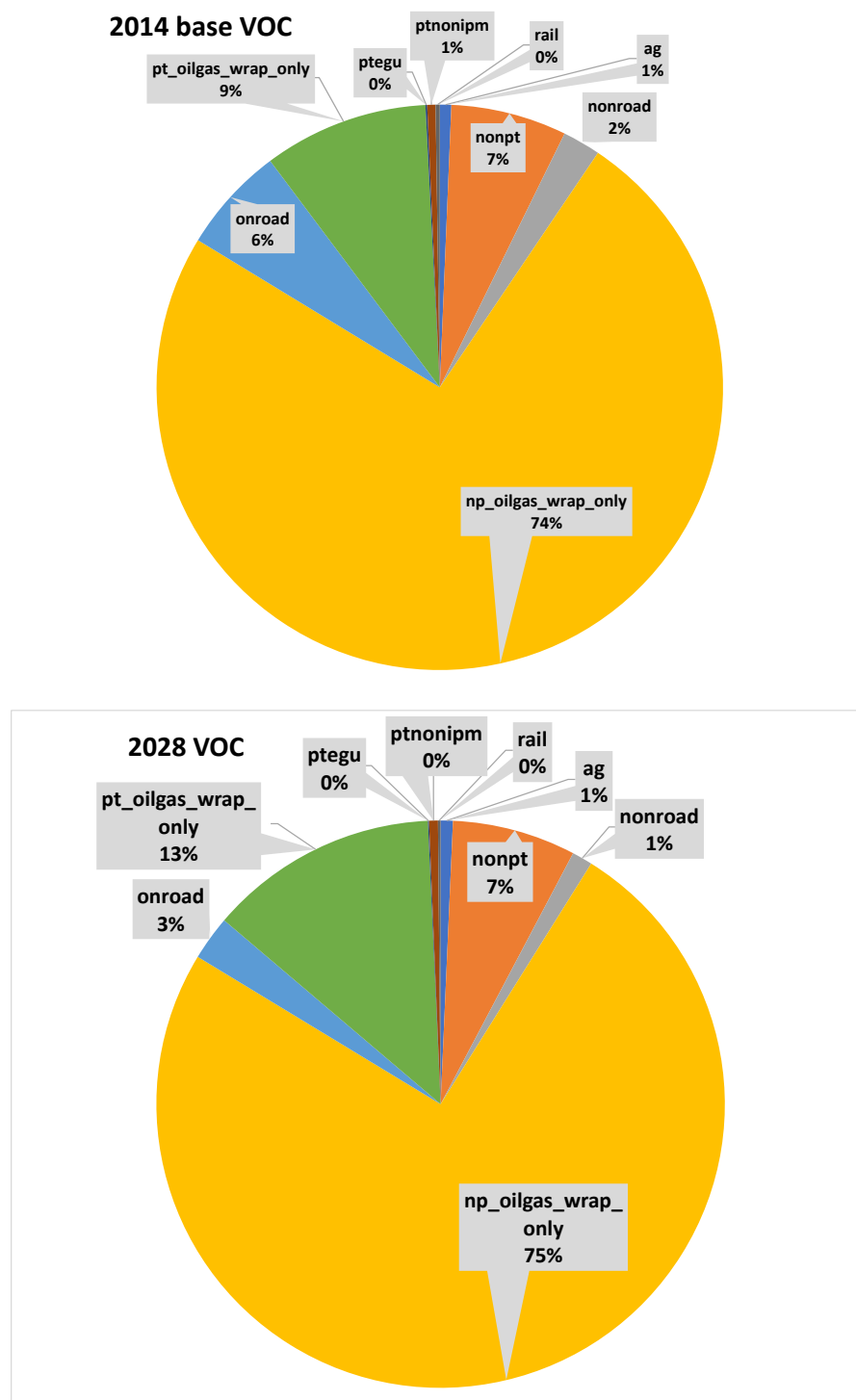


Figure 4-10. Distribution of New Mexico VOC emissions across source sectors for the 2014 (top) and 2028 (bottom) base cases.

4.5 2028 New Mexico Oil and Gas Control Strategy

The WESTAR/Ramboll Team provided the New Mexico 2028 O&G base case emissions to the NMED. The Eastern Research Group (ERG) under separate contract with NMED implemented the emission controls in the 2028 NM O&G emissions based on their interpretation of the proposed New Mexico “Ozone Precursor Rule for Oil and Natural Gas Sector.”³⁶ The 2028 O&G Control Strategy reduced O&G emissions in 7 counties in New Mexico.

The 2028 NM O&G controlled emissions were processed by SMOKE and substituted for the 2028 NM O&G Base Case emissions to create the 2028 O&G Control Strategy emissions scenario. The only difference between the NM OAI Study 2028 Base Case and 2028 O&G Control Strategy were the controls on O&G emissions in New Mexico as implemented by ERG.

Table 4-9 displays the New Mexico state-wide O&G emissions for the 2028 Base Case and 2028 O&G Control Strategy. State-wide O&G NO_x emissions are reduced approximately -45% with similar reductions from both the Point and Non-Point source sectors. State-wide O&G VOC emission reductions are reduced approximately -50% with more reductions coming from the Non-Point (-53%) than Point (-35%) source sectors.

Table 4-9. New Mexico NO_x and VOC O&G emissions (tons per year) for the 2028 Base Case and 2028 NM O&G control strategy.

Source Sector	NO _x Emissions (TPY)			VOC Emissions (TPY)		
	Base	Control	Diff	Base	Control	Diff
Non-Point	61,245	33,144	-46%	181,252	85,564	-53%
Point	41,066	22,872	-44%	30,340	19,608	-35%
Total	102,311	56,016	-45%	211,592	105,172	-50%

Figures 4-11 and 4-12 display the changes in, respectively, NO_x and VOC emissions in the Permian and San Juan Basins between the 2028 base and 2028 control cases. In the Permian Basin, O&G NO_x emissions are estimated to be reduced by approximately 21,000 TPY (64%). In the San Juan Basin, O&G NO_x emissions are estimated to be reduced by approximately 25,000 TPY (44%). 2028 VOC O&G emissions in the Permian and San Juan Basins are estimated to be reduced by approximately 53,000 TPY each (-46% and -55% reduction, respectively).

Figure 4-13 shows the spatial distribution of the differences Non-Point and Point O&G NO_x and VOC emissions between the 2028 Base Case and 2028 O&G Control Strategy scenario. The O&G emission reductions are restricted to the New Mexico portions of the San Juan and Permian Basins.

³⁶ <https://www.env.nm.gov/new-mexico-methane-strategy/wp-content/uploads/sites/15/2020/07/Draft-Ozone-Precursor-Rule-for-Oil-and-Natural-Gas-Sector-Version-Date-7.20.20.pdf>



Figure 4-11. Comparison of 2028 Base Case and 2028 NM O&G control strategy NO_x emissions for the Non-Point (top) and Point (bottom) source sectors and the Permian (left) and San Juan (right) basins.

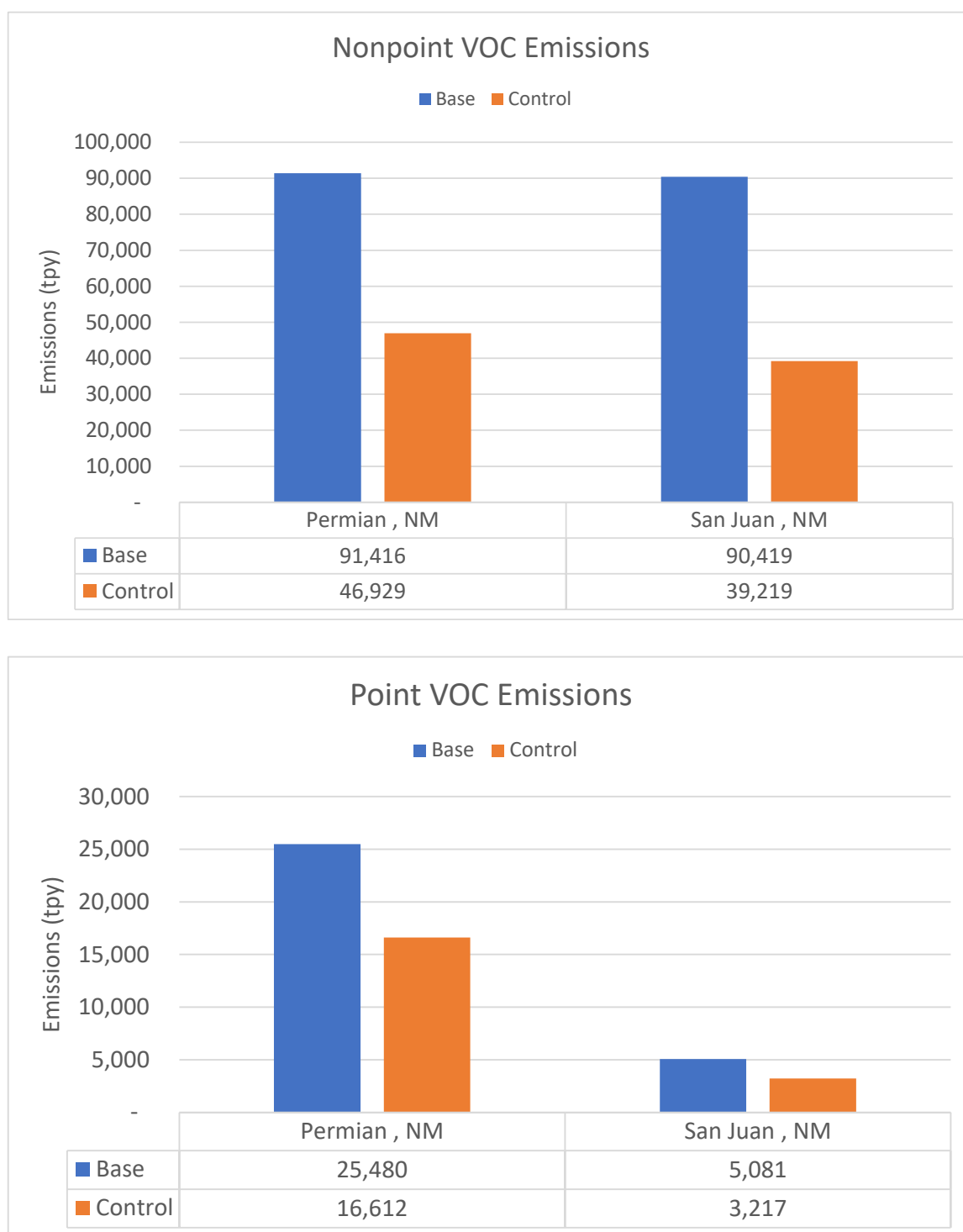


Figure 4-12. Comparison of 2028 Base Case and 2028 NM O&G control strategy VOC emissions for the Non-Point (top) and Point (bottom) source sectors and the Permian (left) and San Juan (right) basins.

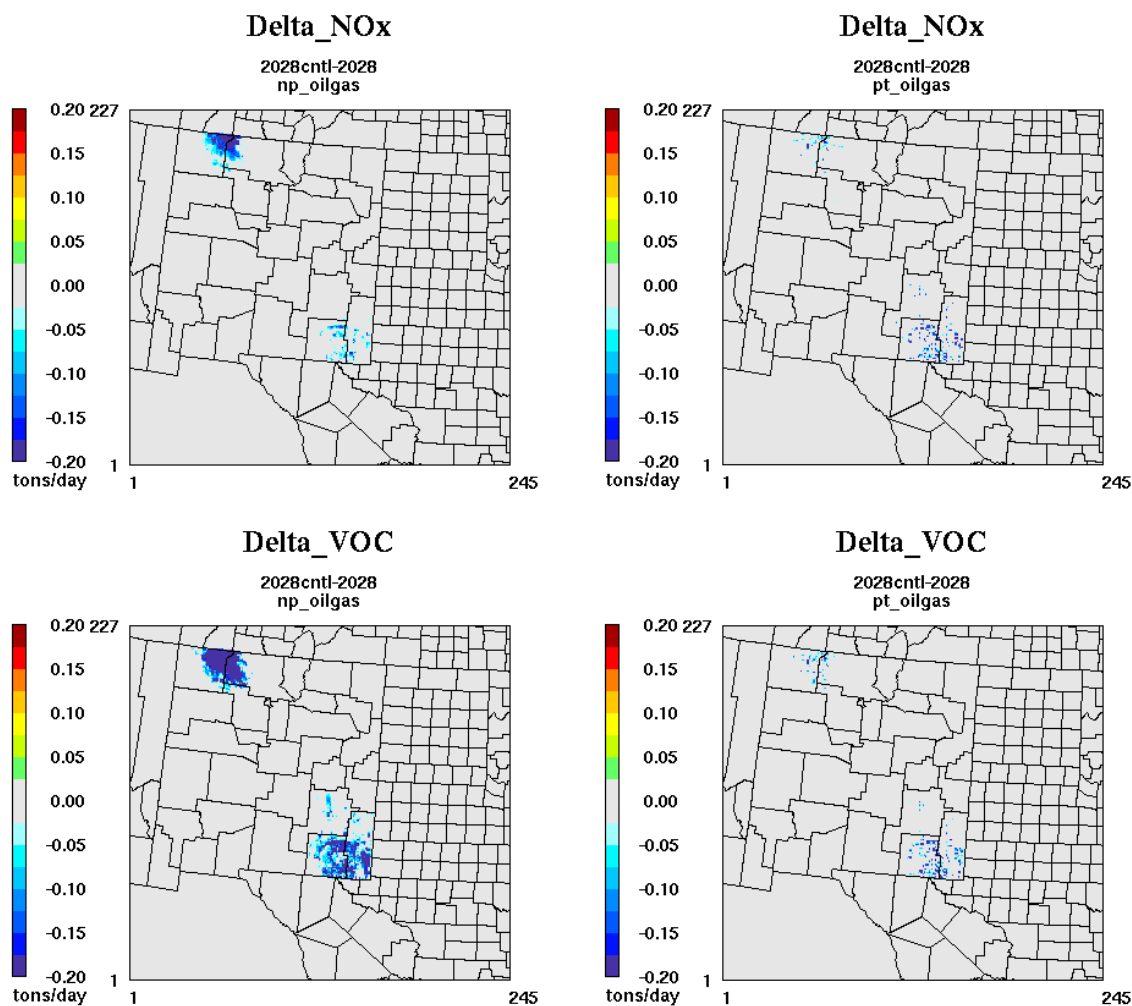


Figure 4-13. Differences in 2028 O&G Control Strategy and 2028 Base Case oil and gas NO_x (top) and VOC (bottom) emissions for the Non-Point (left) and Point (right) source sectors.

5. DIAGNOSTIC SENSITIVITY TESTS

Several CAMx diagnostic sensitivity tests were conducted to evaluate the effects that alternative meteorological inputs have on ozone concentrations.

5.1 WRFCAMx Processing of 2014 WRF Output

The WRFCAMx processor maps WRF meteorological fields to the format required by CAMx. It also calculates turbulent vertical exchange coefficients that define the rate and depth of vertical mixing in CAMx. Several options are available in WRFCAMx to derive vertical turbulent exchange coefficient (also known as Kv or vertical diffusivity) fields from WRF output. The Kv fields are diagnosed from wind, temperature, and Planetary Boundary Layer (PBL) parameters in WRFCAMx. For this application, the WRFCAMx processing was performed to generate two sets of Kv profiles using two different Kv options in WRFCAMx, the CMAQ-like and YSU Kv profile options.

The CAMx Kv_patch pre-processor program was used to set the minimum Kv value to 0.1 to 1.0 m²/s in the lowest 100 m of the atmosphere depending on the amount urban land use category in a grid cell. This is done to account for the urban heat island effect that enhances vertical mixing through-out the day and night.

WRF was run with 36 vertical levels (35 vertical layers) as shown in Table 2-1. For the NM OAI Study, a layer collapsing strategy was employed that reduced the 35 WRF vertical layers to 25 layers in CAMx, which reduces the CAMx run time by about a third. Table 5-1 displays the WRF to CAMx layer collapsing strategy. This is the same layer collapsing study employed by WRAP-WAQS 2014 modeling platform.

5.2 CAMx Meteorological Diagnostic Sensitivity Tests

Four separate CAMx 2014 36/12/4-km diagnostic sensitivity tests were conducted for the first portion of the summer 2014 modeling episode that spanned May 15 to June 4, 2014. The purpose of the four meteorological inputs CAMx sensitivity tests was to identify the optimal meteorological inputs for the final CAMx 2014 base case simulation. The four sets of CAMx simulations were based on the WRF/NAM and WRF/ERA5 2014 36/12/4-km simulations described in Chapter 2 processed by WRFCAMx to generate two sets of vertical mixing coefficient (Kv) as described above:

1. WRF/NAM with CMAQ Kv
2. WRF/NAM with YSU Kv
3. WRF/ERA5 with CMAQ Kv
4. WRF/ERA5 with YSU Kv

Table 5-1. WRF to CAMx vertical layer collapsing strategy used in the NM OAI Study.

CAMx Layers	WRF Layers	WRF hybrid eta	WRF Pressure (mb)	Height (m)
	0	1.0000	1000.0	0
	1	0.9985	998.6	12
1	2	0.9970	997.2	24
	3	0.9950	995.3	40
2	4	0.9930	993.4	56
	5	0.9910	991.5	72
3	6	0.9880	988.6	97
	7	0.9850	985.8	121
4	8	0.9800	981.0	162
5	9	0.9700	971.5	243
6	10	0.9600	962.0	326
7	11	0.9500	952.5	409
	12	0.9400	943.0	492
8	13	0.9300	933.5	577
9	14	0.9100	914.5	747
10	15	0.8900	895.5	921
11	16	0.8700	876.5	1098
12	17	0.8400	848.0	1369
13	18	0.8000	810.0	1742
14	19	0.7600	772.0	2130
15	20	0.7200	734.0	2533
16	21	0.6800	696.0	2954
17	22	0.6400	658.0	3393
18	23	0.6000	620.0	3854
19	24	0.5500	572.5	4463
	25	0.5000	525.0	5115
20	26	0.4500	477.5	5816
	27	0.4000	430.0	6576
21	28	0.3500	382.5	7408
	29	0.3000	335.0	8328
22	30	0.2500	287.5	9360
	31	0.2000	240.0	10541
23	32	0.1500	192.5	11930
	33	0.1000	145.0	13630
24	34	0.0600	107.0	15355
	35	0.0270	75.7	17205
25	36	0.0000	50.0	19260

Figures 5-1 and 5-2 summarize the CAMx MDA8 ozone normalized mean bias (NMB) and error (NME) statistical performance metrics for each site in New Mexico and the four WRF meteorological inputs sensitivity tests. The statistics presented in these figures were calculated using a 60 ppb cutoff value relative to observed MDA8 ozone concentrations to understand the performance of each sensitivity test when ozone concentrations are most relevant to the NAAQS. Figure 5-1 shows that the NMB is generally within $\pm 10\%$ (colored grey) at almost all sites (note that the NMB performance goal is within $\pm 5\%$ and performance criteria is within $\pm 15\%$). All of the sensitivity simulations have an under-prediction bias for observed ozone greater than 60 ppb at sites in the southern portion of the domain such that for one or two sites have a bias even lower than -10% (i.e., colored bright green). The WRF/NAM with CMAQ Kv sensitivity test has slightly better performance than the others with less underestimation bias (e.g., all sites but one are within $\pm 10\%$ compared to two sites for the other tests). Figure 5-2 shows that the NME is also generally within the performance goal (less than 15%) in all cases, with the southern portions of NM showing the largest errors but still within the performance criteria (less than 25%). The figure shows that CAMx using the WRF/NAM inputs tends to have slightly lower error and better ozone performance than when the WRF/ERA5 meteorological inputs are used.

Figure 5-3 presents soccer plots of bias and error for observed ozone above 60 ppb and all four CAMx sensitivity tests. This figure plots site-specific bias versus error with performance lines in the shape of a soccer goal, when the site-specific bias and error symbol falls within the soccer goal area (i.e., the red box) it is easy to see when the ozone performance goals are achieved. The figure shows that all sites have NMB and NME that fall within the performance criteria for bias ($\leq \pm 15\%$) and error ($\leq 25\%$), with most sites having an underestimation bias of the high (> 60 ppb) observed ozone concentrations. The CAMx simulations with the WRF/NAM meteorological inputs has slightly better performance than when the WRF/ERA5 inputs are used as more sites fall within the performance goal area. Comparison between the NAM cases indicate that the CAMx sensitivity test with CMAQ Kv has slightly smaller errors relative to the test with YSU Kv.

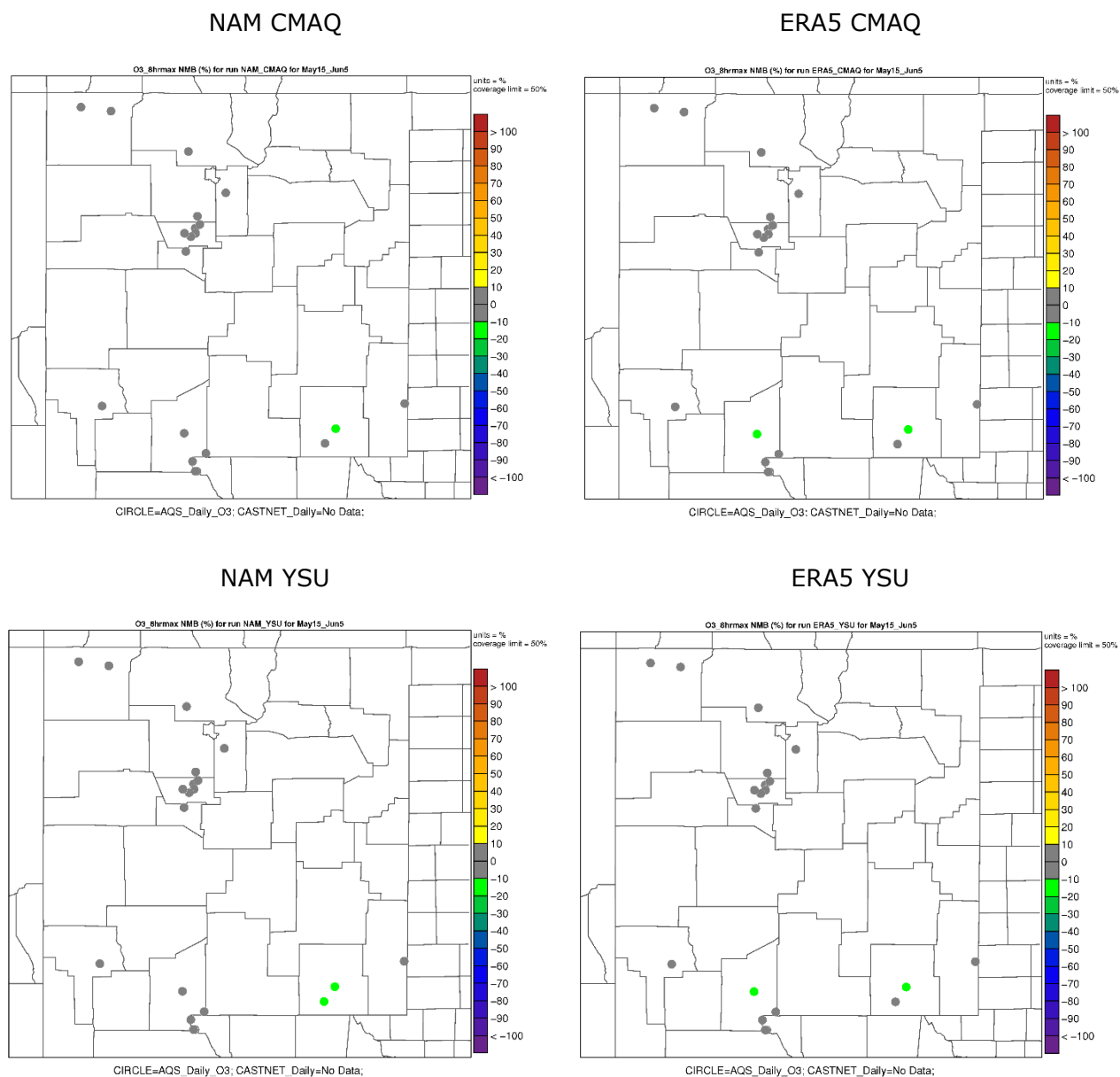


Figure 5-1. Comparison of sensitivity tests NMB with 60 ppb cutoff spatial plots over NM.

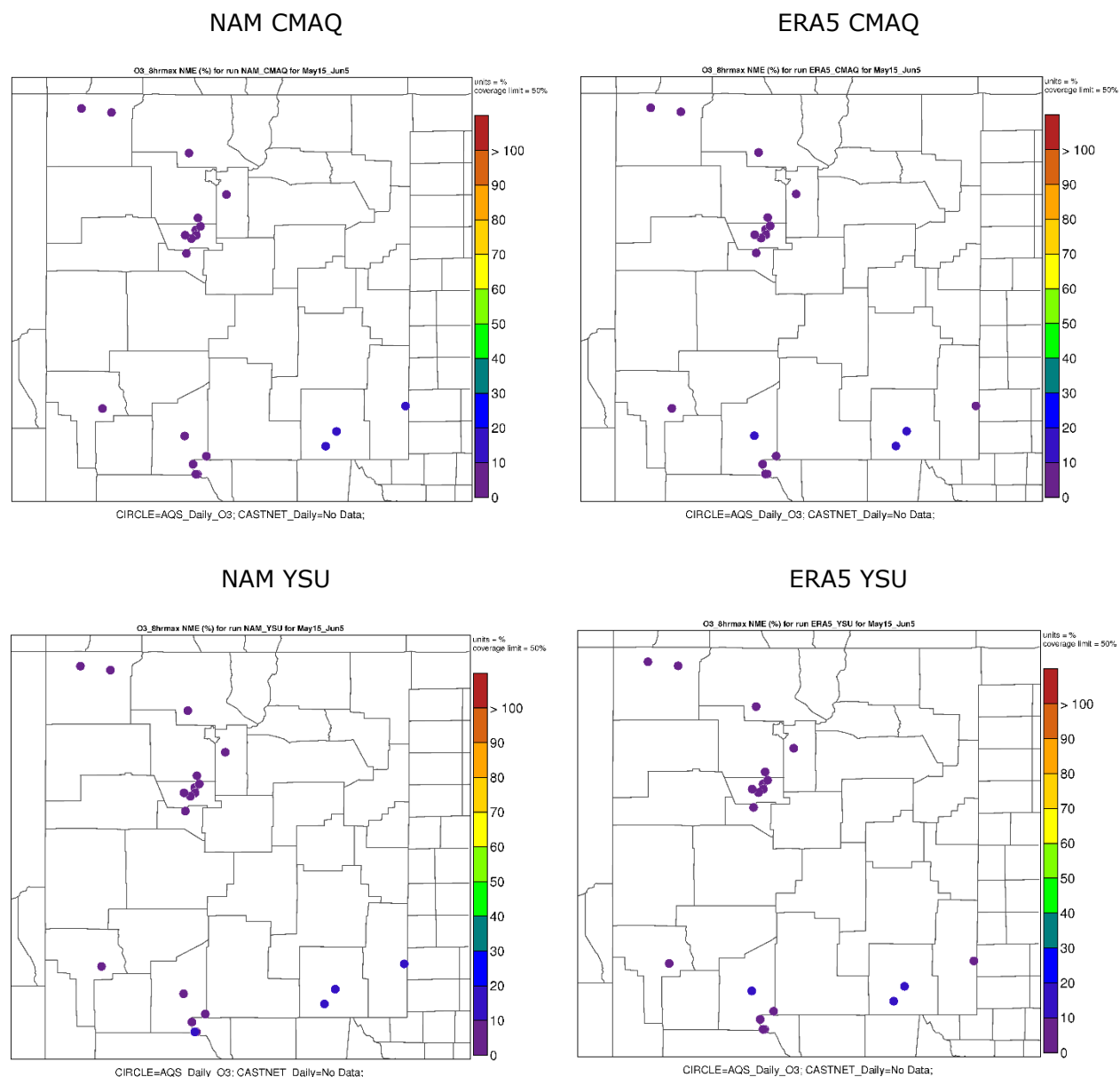


Figure 5-2. Comparison of sensitivity tests NME with 60 ppb cutoff spatial plots over NM.

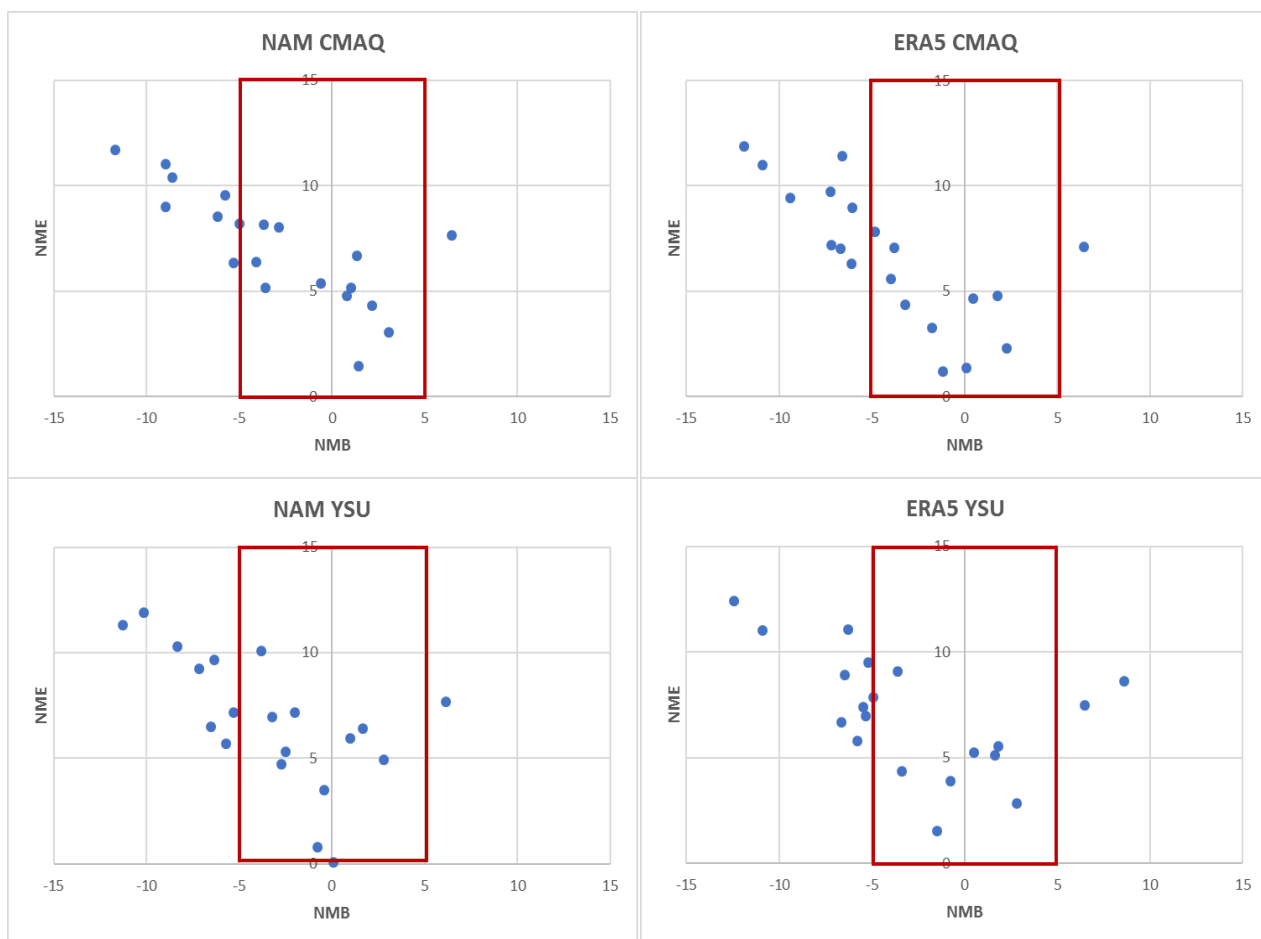


Figure 5-3. Comparison of sensitivity tests soccer plots with 60 ppb cutoff. Red rectangle indicates the performance goal soccer area.

Figures 5-4 to 5-7 present time series of predicted and observed MDA8 ozone concentrations for selected sites in Doña Ana, Eddy and Sandoval counties. At the Solano Road site in Doña Ana County the time series shows that the observed peak ozone concentration on May 29 is matched very well by the CAMx WRF/NAM sensitivity tests, while the CAMx WRF/ERA5 sensitivity test under-predicts by approximately 10 ppb (Figure 5-4). At the Desert View site, which is also in Doña Ana County, all four CAMx sensitivity tests underestimate the high observed ozone on May 28-29, but the CAMx WRF/NAM tests perform slightly better than the CAMx WRF/ERA5 test (Figure 5-5). At the Carlsbad site in Eddy County all test cases under-predict the high ozone concentration from May 27 to May 31 (Figure 5-6). For the site in Sandoval county (Figure 5-7) all four CAMx sensitivity tests track the daily variations of the observed MDA8 ozone including getting the timing and values of the observed ozone peak on May 29, but the CAMx WRF/NAM with CMAQ Kv test exhibits the lowest biases.

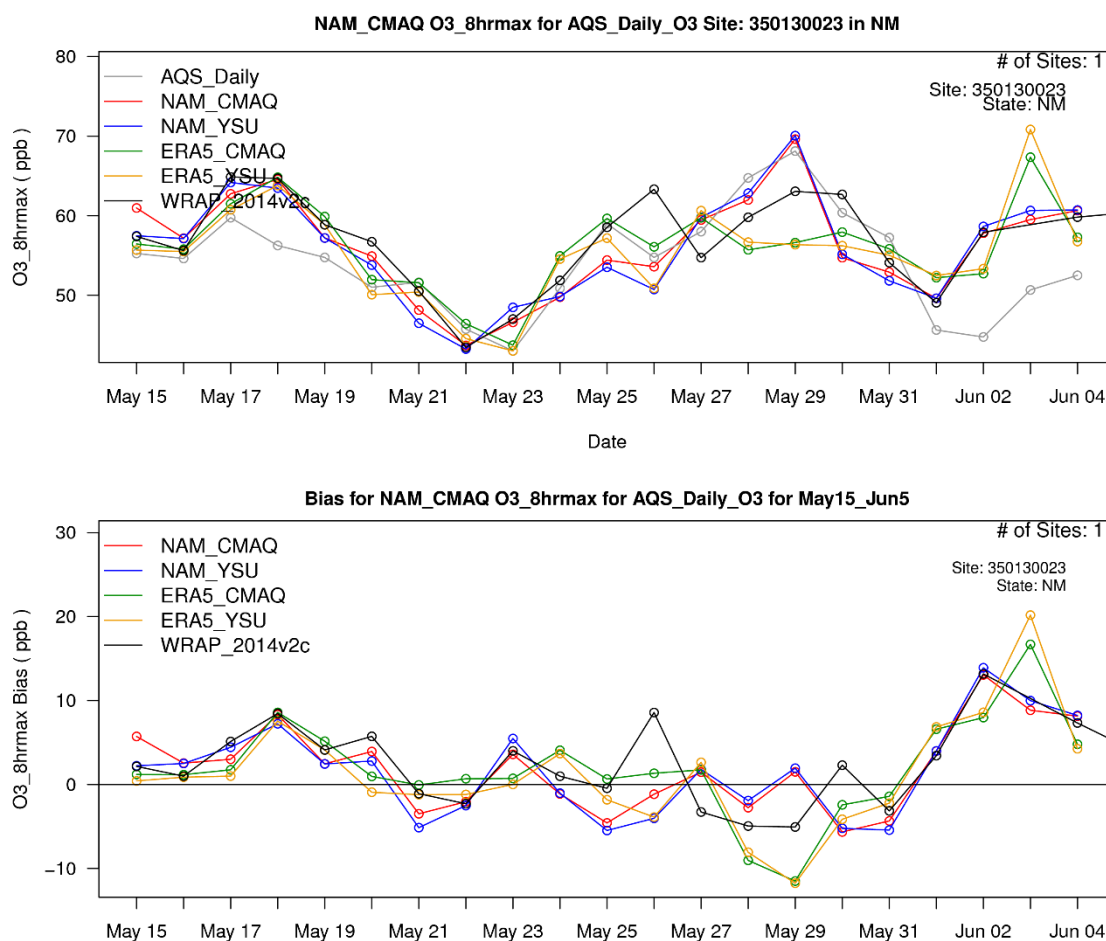


Figure 5-4. Timeseries comparison of sensitivity tests with observations (top) and bias (bottom) at Solano Road site in Doña Ana County

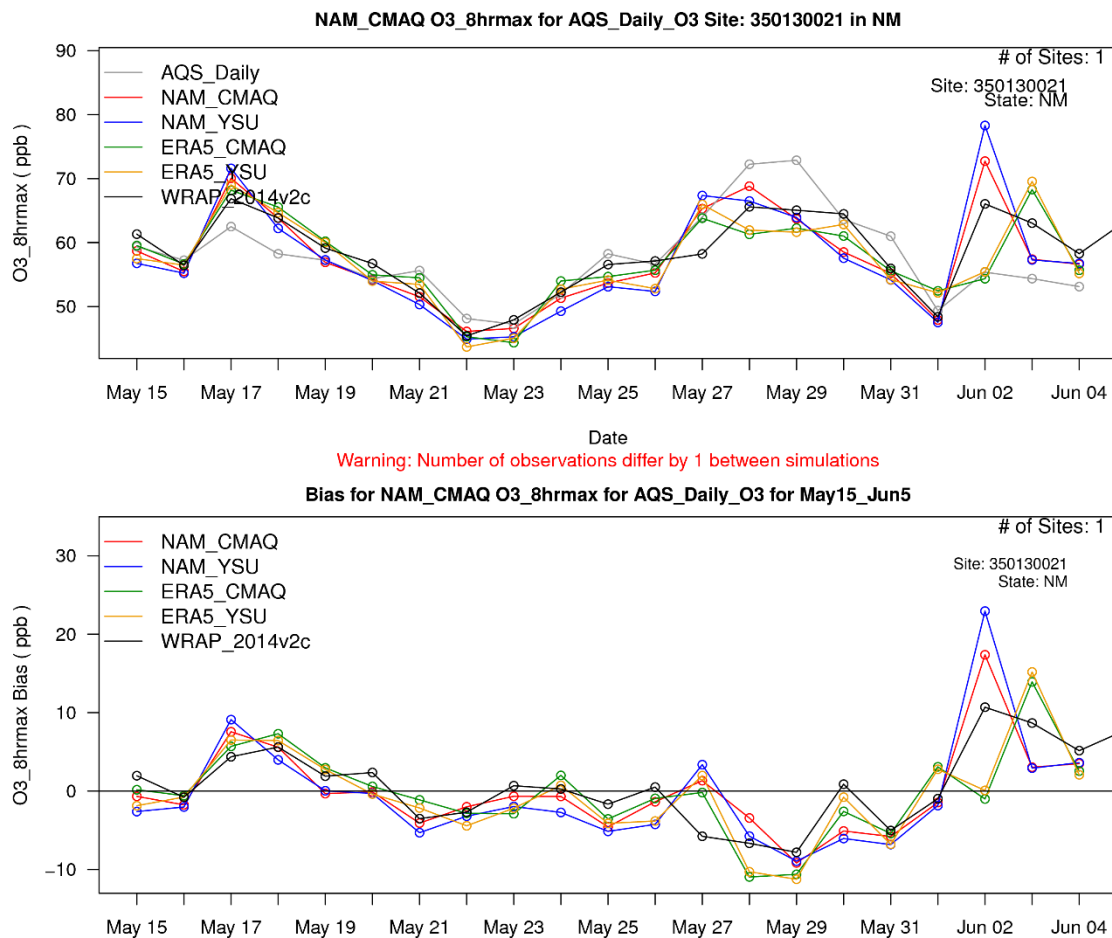


Figure 5-5. Timeseries comparison of sensitivity tests with observations (top) and bias (bottom) at Desert View site in Doña Ana County

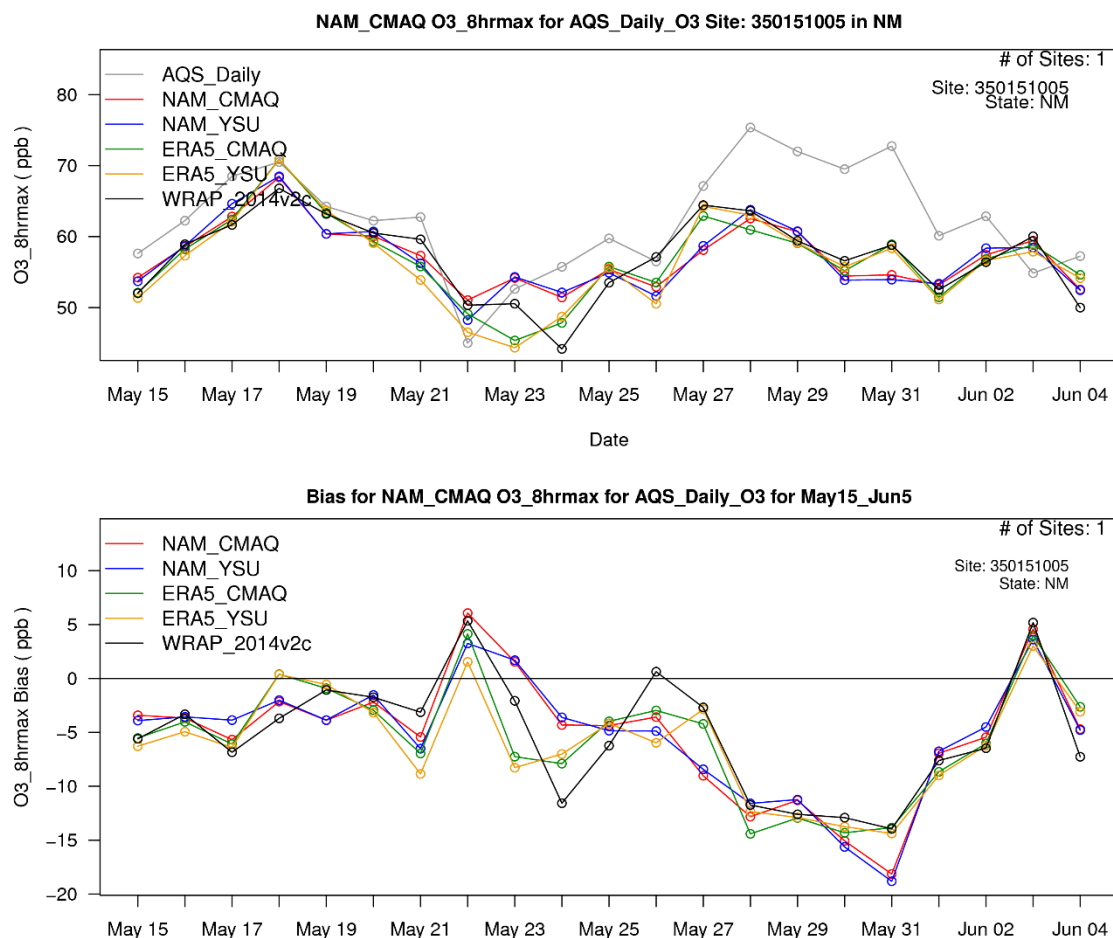


Figure 5-6. Timeseries comparison of sensitivity tests with observations (top and bias (bottom) at Carlsbad site in Eddy County

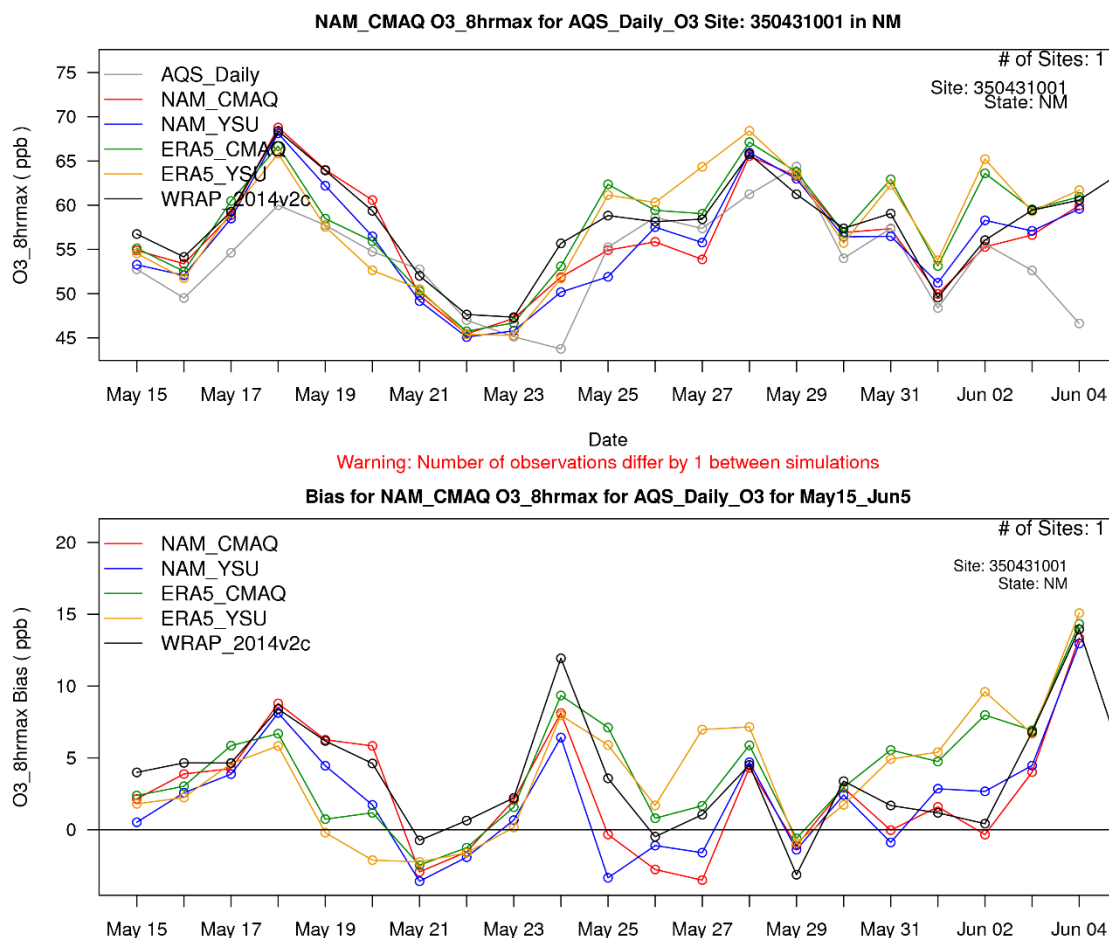


Figure 5-7. Timeseries comparison of sensitivity tests with observations (top) and bias (bottom) at Albuquerque site in Sandoval County

5.3 Summary of CAMx Diagnostic Sensitivity Tests

All four of the CAMx meteorological sensitivity cases have biases and errors well within the performance criteria and in most cases even within the more stringent performance goals. For the modeled episode, the differences in performance among all the cases considered are relatively minor. On some sites and days, CAMx using the WRF/NAM meteorology tends to capture peak ozone concentrations better than when the WRF/ERA5 meteorology is used. Based on the results presented here, the final CAMx 2014 base case model configuration used the WRF/NAM with CMAQ Kv treatment meteorological inputs.

6. 2014 BASE CASE MODELING AND MODEL PERFORMANCE EVALUATION

The NM OAI Study conducted two CAMx 2014 36/12/4-km base case simulations. The original 2014 base case simulation used CAMx v7.0 and biogenic emissions in the 4-km based on the MEGAN v3.1 model and is documented in Ramboll and WESTAR (2020c). There were errors in the CAMx v7.0 source apportionment algorithms that did not significantly affect the CAMx v7.0 2014 base case ozone estimates but would affect planned future year ozone source apportionment modeling. So, a second CAMx 2014v2 base case simulation was performed using CAMx v7.1 that had corrections to the ozone source apportionment algorithms. The revised CAMx v7.1 2014v2 base case simulation also updated the biogenic emissions in the 4-km domain using the BEIS v3.7 biogenic emissions model. The MEGAN v3.1 biogenic model used in the first CAMx v7.0 2014 base case was missing leaf area index (LAI) data for urban areas so produced zero biogenic VOC emissions for the urban land use type. The development of New Mexico-specific urban LAI inputs was beyond the resource and time constraints of the study, so BEIS biogenic emissions were used for the revised 2014v2 CAMx base case simulation. Details on the CAMx 2014v2 final base case simulation and model performance are provided in Ramboll and WESTAR (2021) with a summary provided below.

6.1 Final CAMx 2014v2 Base Case Configuration

The final CAMx meteorological inputs were based on the WRF/NAM simulations using the CMAQ-like Kv profiles as described in Chapters 2 and 5.

The 2014 emissions used in the 36-km and 12-km domains were the same as the WRAP-WAQS 2014v2 emissions. For the 4-km New Mexico domain, the WRAP 2014v2 emissions were processed by the SMOKE emissions model to generate the gridded hourly speciated emissions for CAMx. Chapter 4 describes the updates to the WRAP-WAQS 2014v2 emissions for New Mexico and the development of the emission inputs for the New Mexico 4-km domain.

Table 6-1 summarizes the CAMx configuration and options used for the CAMx 2014v2 base case simulation. Version 7.1 (v7.1) of CAMx released in January 2021 was used in the final 2014v2 base case simulation. CAMx was operated using the 36/12/4-km nested grid structure shown in Figure 1-1 using two-way grid nesting for all simulations. Boundary Conditions (BCs) for the CAMx most outer 36-km 36US modeling domain lateral boundaries were based on output from a 2014 simulation of the GEOS-Chem global chemistry conducted by WRAP for their 2014v2 modeling platform. CAMx was started on May 1, 2016 using the 36/12/4-km domains that allowed the model over two-weeks to initialize the model and wash out the initial concentrations before the first high ozone day on May 17, 2014.

Other CAMx model options and setup are defined in Table 6-1. The PPM advection solver (Colella and Woodward, 1984) was used for horizontal transport along with the spatially varying (Smagorinsky) horizontal diffusion approach. K-theory was used for vertical diffusion using the CMAQ-like Kv profiles from the WRF/CAMx processing of the WRF/NAM output. The CB6r4 gas-phase chemical mechanism was selected because it includes the very latest chemical kinetic rates with halogen chemistry that affects ozone levels over the ocean. The latest aerosol mechanism was used in CAMx along with the

standard wet and dry deposition schemes. The Plume-in-Grid module was used to treat the near-source chemistry and dispersion of major NO_x emissions sources in the New Mexico 4-km domain for sources with greater than 5 tons per day NO_x emissions.

Table 6-1. Final CAMx model configuration for the 2014v2 base case simulation in NM OAI Study.

Science Options	CAMx	Comment
Model Codes	CAMx v7.1	Latest version of CAMx at time of study released in January 2020 (www.camx.com)
Horizontal Grid Mesh	36/12/4-km	
36-km grid	148 x 112 cells	36US domain
12-km grid	227 x 215 cells	12WUS2 domain. Includes buffer cells
4-km grid	245 x 227 cells	New Mexico 4-km domain. Includes buffer cells
Vertical Grid Mesh	25 vertical layers, defined by WRF	Layer 1 thickness ~20 m. Model top at 50 mb (~19 km). Layer collapsing from 35 vertical layers in WRF
Grid Interaction	36/12/4 km two-way nesting	
Initial Conditions	Start on May 1, 2014	First high ozone day is May 17, 2014
Boundary Conditions	WRAP 2014 GEOS-Chem	For 36US domain lateral boundaries
Emissions		
Baseline Emissions Processing	SMOKE, SMOKE-MOVES2014, BEIS v3.7	WRAP/WAQS 2014v2 emissions
Sub-grid-scale Plumes	Plume-in-Grid for major NO _x sources in New Mexico	Point sources with NO _x emission s greater than 5 tons per day
Chemistry		
Gas Phase Chemistry	CB6r4	Latest chemical reactions and kinetic rates with halogen chemistry (Yarwood et al., 2010)
Meteorological Processor	WRF-CAMx	Compatible with CAMx v7.0
Horizontal Diffusion	Spatially varying	K-theory with Kh grid size dependence
Vertical Diffusion	CMAQ-like Kv	Evaluated YSU Kv scheme
Diffusivity Lower Limit	Kv-min = 0.1 to 1.0 m ² /s in lowest 100 m	Depends on urban land use fraction
Deposition Schemes		
Dry Deposition	Zhang dry deposition scheme	(Zhang et. al, 2001; 2003)
Wet Deposition	CAMx -specific formulation	rain/snow/graupel
Numerics		
Gas Phase Chemistry Solver	Euler Backward Iterative(EBI)	EBI fast and accurate solver
Vertical Advection Scheme	Implicit scheme w/ vertical velocity update	Emery et al., (2009a,b; 2011)
Horizontal Advection Scheme	Piecewise Parabolic Method (PPM) scheme	Colella and Woodward (1984)
Integration Time Step	Wind speed dependent	~0.5-1 min (4-km), 1-5 min (12-km), 5-15 min (36-km)

6.2 Ozone Model Performance Goals and Criteria

Emery and co-workers (2016) analyzed almost 100 PGM model applications and developed a set of PGM model performance goals and criteria based on the variability in the past PGM model performance. “Goals” indicate statistical values that approximately a third of the top performance past PGM applications have met and should be viewed as the best a model can be expected to achieve. “Criteria” indicates statistics values that about two thirds of past PGM applications have met and should be viewed as what a majority of the models have achieved. The CAMx revised 2014v2 and original 2014 base case simulations ozone model performance statistics for normalized mean bias (NMB) and normalized mean error (NME) are compared against the ozone model performance goals and criteria developed by Emery et al., (2016) that are given in Table 6-2.

Table 6-2. Recommended ozone benchmarks for photochemical model statistics (Source: Emery et al., 2016).

Species	NMB		NME		r	
	Goal	Criteria	Goal	Criteria	Goal	Criteria
1-hr & MDA8 Ozone	<±5%	<±15%	<15%	<25%	>0.75	>0.50

6.3 Spatial Ozone Model Performance

Figures 6-1 and 6-2 display the spatial distribution of bias (NMB) performance at monitoring sites in the 4-km NM domain for the revised 2014v2 and original 2014 CAMx base case simulation with and without using a 60 ppb observed ozone cutoff concentrations (i.e., only include predicted and observed MDA8 ozone pairs in the statistics when the observed MDA8 ozone is greater than 60 ppb). When the symbols are grey, they achieve the within ±5% ozone bias Performance Goal and when the symbols are the brightest green or yellow colors they are within the ozone bias Performance Criteria (i.e., between ±5% and ±15%).

With the exception of one monitoring site in El Paso, the NMB at all of the ozone sites in the 4-km domain achieve the ozone Performance Criteria using no cutoff in both CAMx base case simulations, although some sites have an overestimation bias greater than 5% Performance Goal (Figure 6-1). The CAMx 2014v2 and 2014 base case ozone bias performance looks nearly identical with the only noticeable differences being two sites (one in Doña Ana County and one in Luna County) that achieve the ozone bias Performance Goal in the revised 2014v2 CAMx base case (i.e., are colored grey in Figure 6-1, top) but have bias between the 5% and 15% in the original CAMx base case (Figure 6-1, bottom) so fall between the Performance Goal and Criteria (i.e., are colored bright yellow).

Whereas the CAMx base cases tend to have a small ozone overestimation bias when no observed ozone 60 ppb cutoff is used, when using a 60 ppb observed ozone cutoff both base cases tend to have a small underestimation bias (Figure 6-2). With one exception, when using the cutoff all sites achieve the ozone Performance Criteria and many sites achieve the ozone bias Performance Goal. The bias performance of the two base case simulations are nearly identical. The one exception is the Carlsbad site in Eddy County that is between the Performance Goal and Criteria (i.e., between -5% and -15%) in the

original 2014 base case (Figure 3-2, bottom), but has a NMB between -15% and -20% in the revised 2014v2 base case so fails to achieve the ozone bias Performance Criteria (Figure 3-2, top).

We also compared the spatial model performance of the two base cases for error (NME) and correlation (r), but the spatial maps were identical so did not provide any relevant information on the relative performance of the two base case simulations.

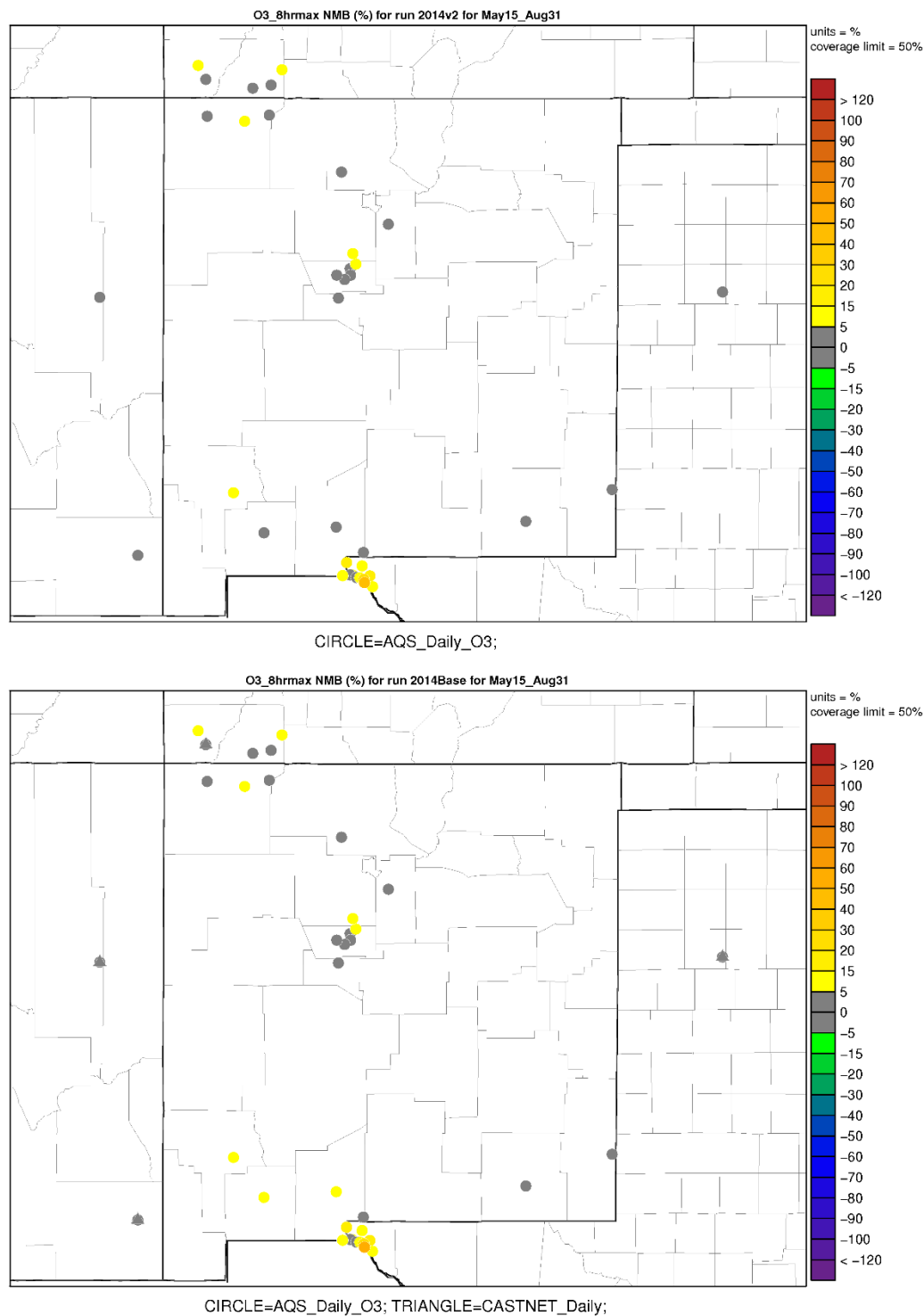


Figure 6-1. Normalized Mean Bias (NMB) for MDA8 ozone concentrations for the revised 2014v2 (top) and original 2014 (bottom) CAMx base case simulations with no ozone cutoff.

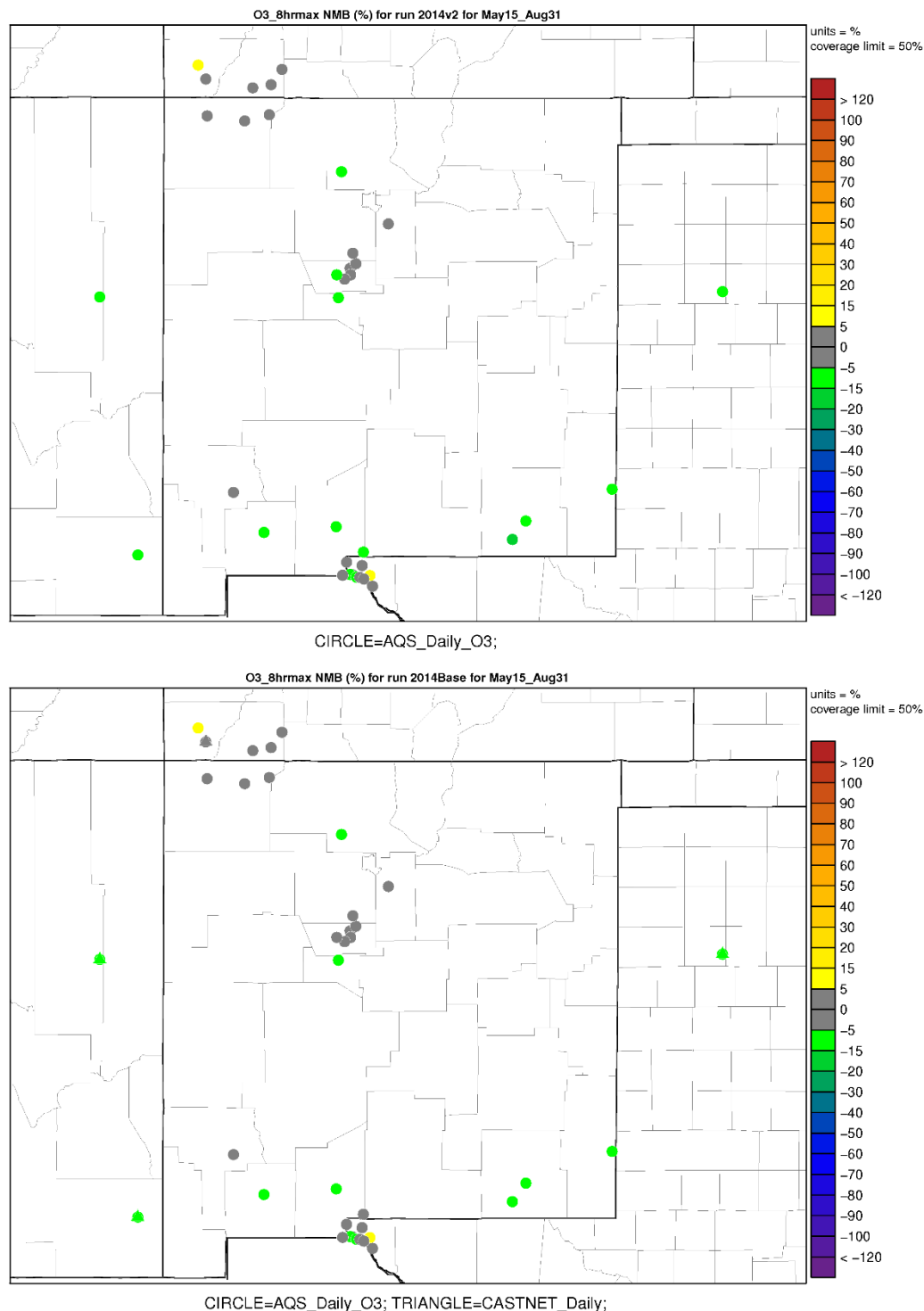


Figure 6-2. Normalized Mean Bias (NMB) for MDA8 ozone concentrations for the revised 2014v2 (top) and original 2014 (bottom) CAMx base case simulations with an observed 60 ppb ozone cutoff.

6.4 Scatter Plots of MDA8 Ozone

Figure 6-3 display scatter plots and summary statistics of MDA8 ozone across AQS or CASTNet sites in the 4-km domain for the revised 2014v2 and original 2014 CAMx base case simulations. The 2014v2 and 2014 MDA8 scatter plots look identical with the MDA8 performance at the AQS sites exhibiting a slight MDA8 ozone overestimation bias as indicated by the center density of the scatterplot being slightly above the 1:1 line of perfect agreement. This is in contrast to the CASTNet MDA8 scatterplots that are centered on the 1:1 line of perfect agreement so the two base case simulations are less biased.

The AQS performance statistics across the 4-km domain for the May-August 2014 modeling period show that the 2014v2 and 2014 MDA8 ozone performance is not exactly identical with the revised 2014v2 base case having a NMB of 4.4% that achieves the ozone bias Performance Goal, whereas the original 2014 base case has a NMB of 6.2% that falls between the ozone bias Performance Goal and Criteria. The 2014v2 NME (10.6%) is also slightly better than the original 2014 base case (10.9%).

Both CAMx base case simulations exhibit extremely good MDA8 ozone model performance across the CASTNet sites in the 4-km domain with near zero bias (-1.4% and +0.1%) and errors (8.1% and 7.9%) that are almost half the ozone error Performance Goal (<15%).

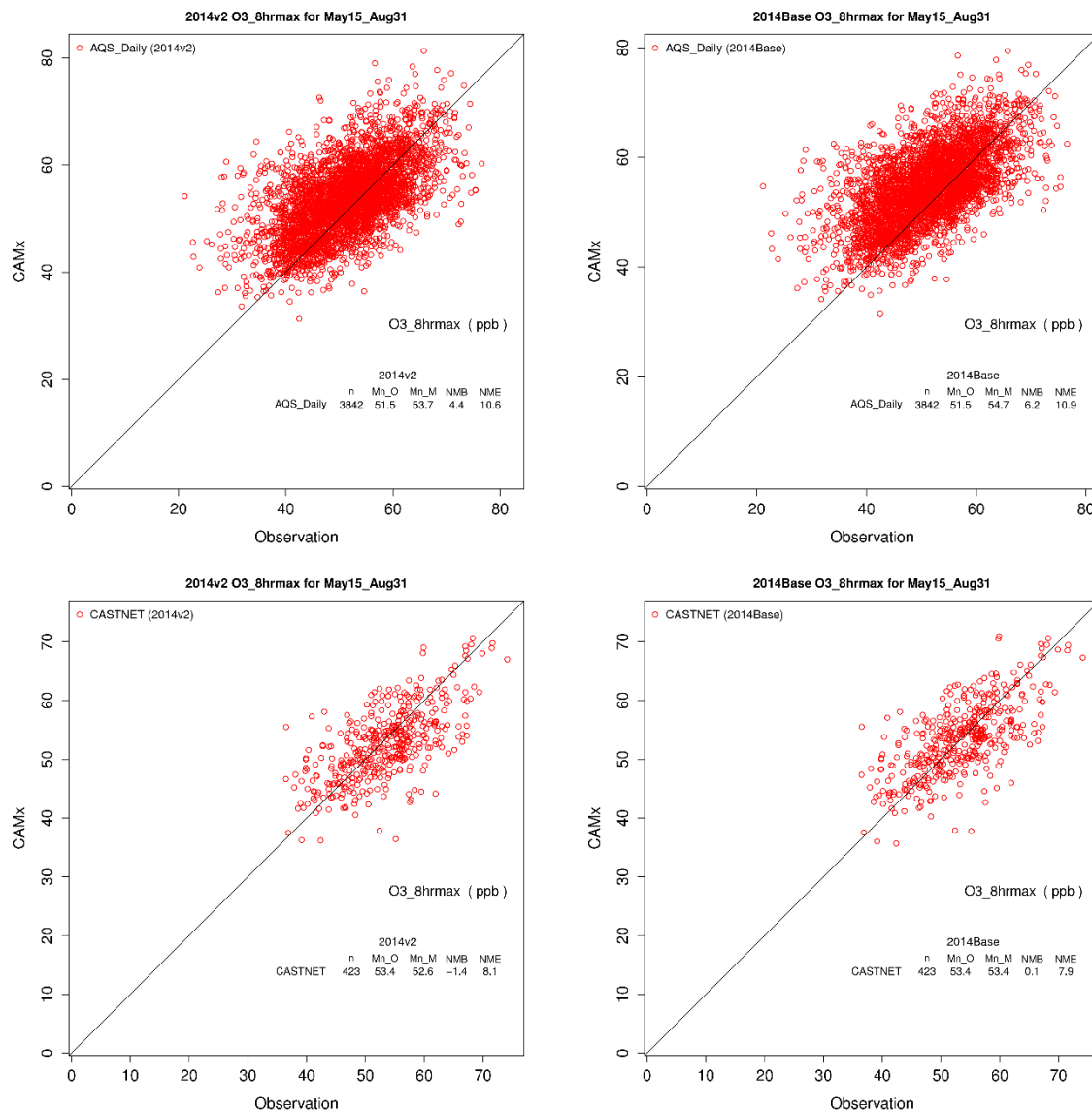


Figure 6-3. Scatter plots of predicted and observed MDA8 ozone concentrations for AQS (top) and CASTNet (bottom) monitoring sites within the 4-km New Mexico domain and the revised 2014v2 (left) and original 2014 (right) CAMx base case simulations.

6.5 MDA8 Ozone Time Series

Example predicted and observed MDA8 ozone time series at selected sites are presented below, with time series at all sites contained in the Appendix in Ramboll and WESTAR (2021). Figure 6-4 displays MDA8 ozone time series at the Desert View monitoring site in Doña Ana County in southern New Mexico. The CAMx MDA8 ozone predictions for the revised 2014v2 (blue) and original 2014 (green) base case simulations are almost on top of each other. In general, when they are a little different the revised 2014v2 MDA8 ozone is slightly lower, although that is not always the case as seen in the MDA8 ozone peaks in early June, mid-July, and end of August.

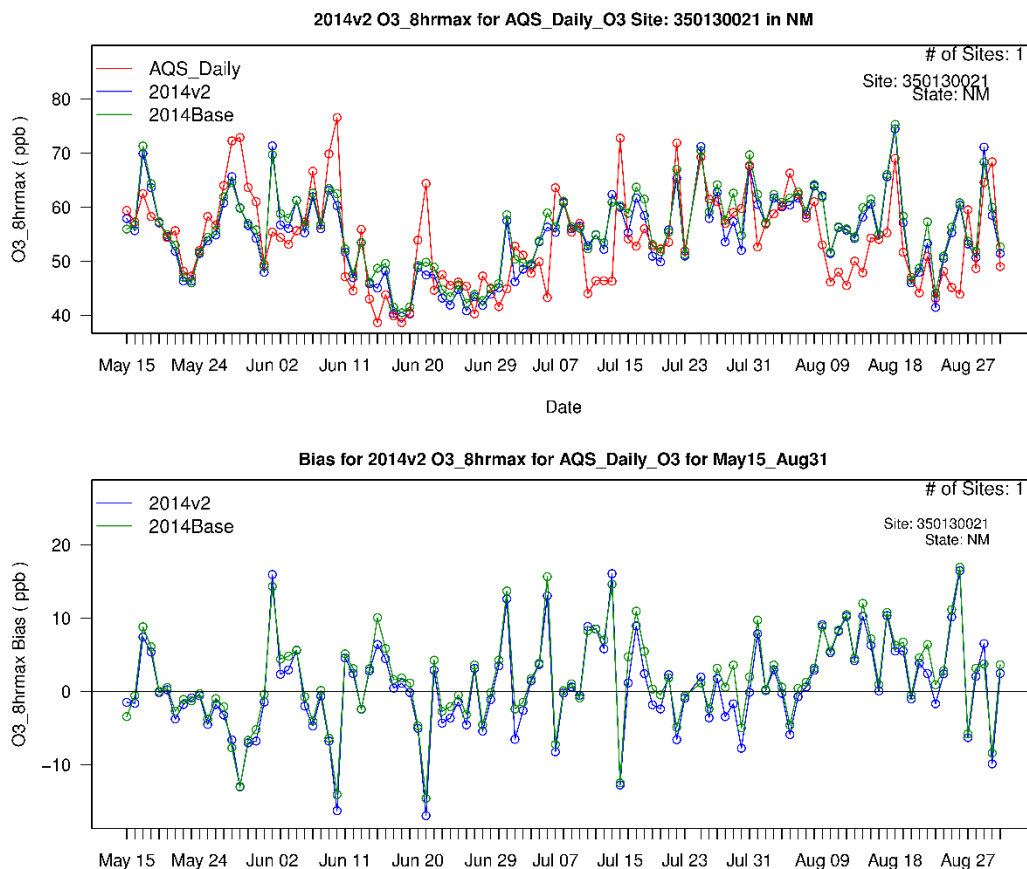


Figure 6-4. Time series of predicted and observed (red) MDA8 ozone at Desert View in Doña Ana County for the CAMx revised 2014v2 (blue) and original 2014 (green) CAMx base case simulations.

The MDA8 ozone time series comparison for the South East Heights monitoring site in Bernalillo County is shown in Figure 6-5. With the exception of a period in early July where the revised 2014v2 base case has a larger underestimation bias compared to the original 2014 base case, the two CAMx base case simulations are predicting nearly identical MDA8 ozone concentrations at this site.

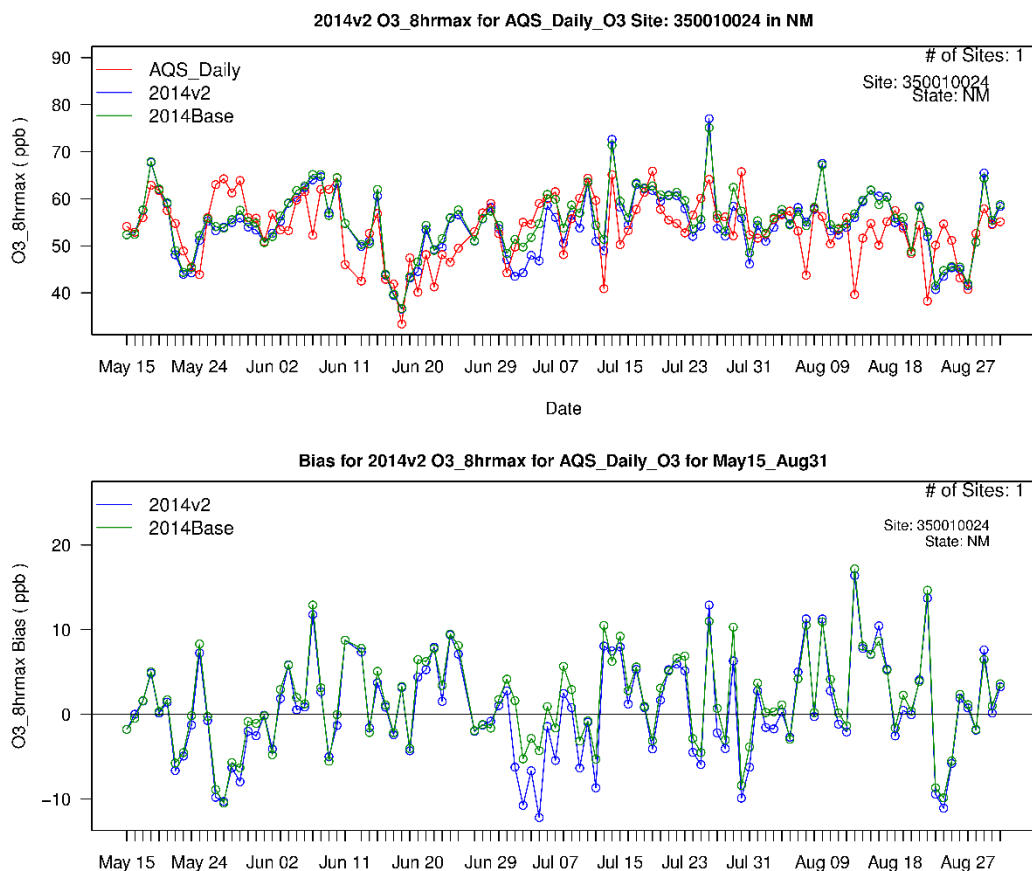


Figure 6-5. Time series of predicted and observed (red) MDA8 ozone at South East Heights in Bernalillo County for the CAMx revised 2014v2 (blue) and original 2014 (green) CAMx base case simulations.

The ozone time series at the Substation monitoring site in San Juan County is shown in Figure 6-6. Both CAMx base cases track the observed MDA8 ozone concentrations very well at the Substation monitoring site. Most of the time, the predicted MDA8 ozone are on top or nearly on top of each other and when different the revised 2014v2 MDA8 ozone is a little lower than the original CAMx 2014 base case.

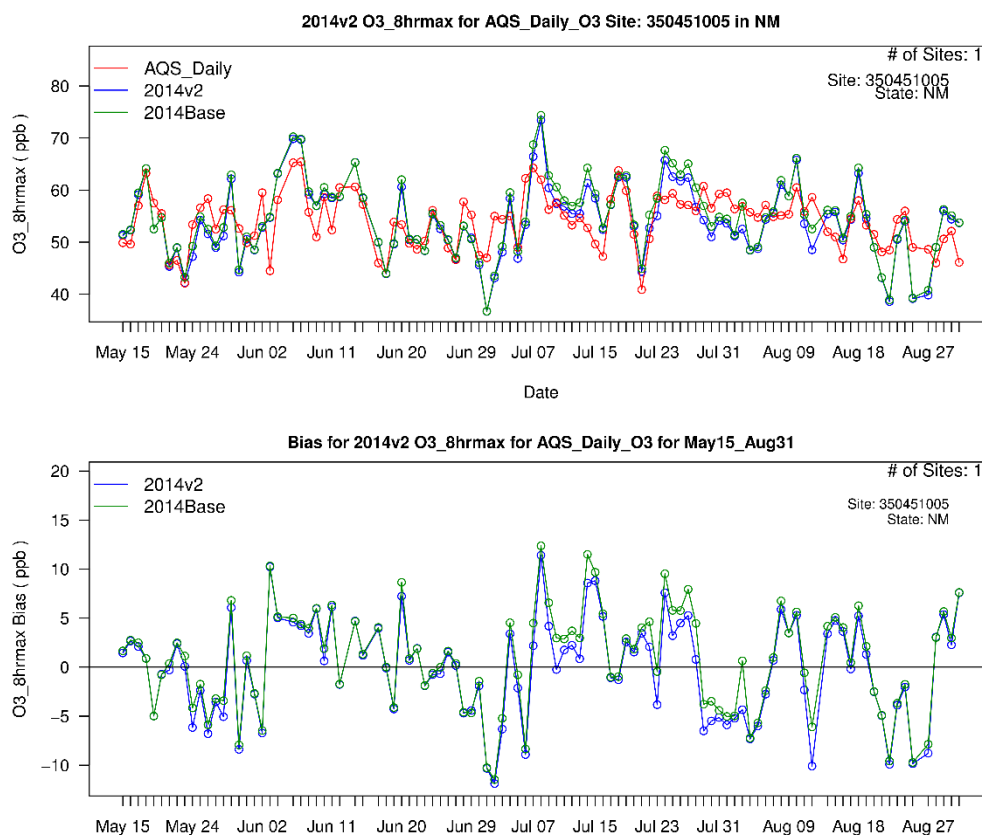


Figure 6-6. Time series of predicted and observed (red) MDA8 ozone at Sub Station in San Juan County for the CAMx revised 2014v2 (blue) and original 2014 (green) CAMx base case simulations.

6.6 Summary Ozone Model Performance Statistics in New Mexico

Ozone model performance statistics were calculated for three geographic regions in New Mexico. The central region was defined as all monitoring sites within Bernalillo County with the southern and northern regions defined as sites, respectively, south and north of Bernalillo County.

Tables 6-3 and 6-4 display the bias and error MDA8 ozone performance statistics with and without the observed MDA8 ozone 60 ppb cutoff for the three New Mexico subregions and the, respectively, original 2014 and revised 2014v2 CAMx base case simulations. The bias and error MDA8 ozone performance statistics are colored green when they achieve the Performance Goal, yellow when they lie between the Performance Goal and Criteria and red when they fail to achieve the Performance Criteria. The CAMx 2014 and 2014v2 base case performance statistics within the three New Mexico subregions are very good and very similar with the bias for the revised 2014v2 base case being 1-2 percentage points lower than the original 2014 CAMx base case simulation. Using no cutoff, when CAMx has a slight ozone overestimation tendency, the revised 2014v2 exhibits better performance statistics than the original 2014 base case. For example, the bias in the southern New Mexico region in original 2014 base case (5.8%) fails to achieve the ozone bias Performance Goal due to too high ozone overestimation, but achieves the ozone bias Performance Goal in the revised 2014v2 base case (3.5%). On the other hand, when an observed ozone 60 ppb cutoff is used the model tends to underestimate ozone a little so the revised 2014v2 base case ozone model performance is degraded a little compared to the original 2014 base case. For example, for the southern New Mexico subregion the original CAMx 2014 base case has a -6.1% NMB that is -7.8% for the revised CAMx 2014v2 base case, both of these NMB ozone performance statistics fall between the ozone bias Performance Goal and Criteria.

Table 6-3. Bias and error MDA8 ozone performance statistics for the original CAMx 2014 base case and the three subregions of New Mexico calculated with and without using an observed MDA8 ozone 60 ppb cutoff.

Region	Nocutoff		Withcutoff	
	NMB(%)	NME(%)	NMB(%)	NME(%)
North NM	4.3	9.1	0	6.4
Bernalillo	4.3	9.4	-2.8	7.1
South NM	5.8	10.5	-6.1	8.5

Table 6-4. Bias and error MDA8 ozone performance statistics for the revised CAMx 2014v2 base case and the three subregions of New Mexico calculated with and without using an observed MDA8 ozone 60 ppb cutoff.

Region	Nocutoff		Withcutoff	
	NMB(%)	NME(%)	NMB(%)	NME(%)
North NM	2.6	8.6	-1.0	6.6
Bernalillo	2.6	9.6	-4.3	8.5
South NM	3.5	10.2	-7.8	9.9

Tables 6-5 and 6-6 contain the bias performance statistics with and without a cutoff for each monitoring site in New Mexico and the, respectively, original CAMx 2014 and revised CAMx 2014v2 base case simulations. When not using the observed ozone cutoff, the original 2014 base case has 59% of the sites achieving the ozone bias Performance Goal with 36% of the sites falling between the Performance Goal and Criteria and one site failing to achieve the ozone bias Performance Criteria due to a 17.4% overestimation bias. The revised 2014v2 base case bias with no cutoff has 68% of the sites achieving the Performance Goal, 27% falling between the Performance Goal and Criteria and one site right at (15.0%) the Performance Criteria.

When an observed ozone cutoff is used, the number of sites achieving the ozone bias Performance Goal is flipped between the two base cases with 68% of the sites achieving the Performance Goal for the original 2014 base case and 59% of the sites achieving the Performance Goal for the revised 2014v2 base case with the remainder of the sites falling between the ozone bias Performance Goal and Criteria.

Table 6-5. Bias MDA8 ozone performance statistics with and without an observed ozone cutoff for each site in New Mexico and the original CAMx 2014 base case simulation.

2014Base (with MEGAN)			
SiteID	SiteNames	NMB No Cutoff	NMB 60 ppb Cutoff
350010023	Del Norte	1.7	-3.9
350010024	South East Heights	3.1	-2.4
350010029	South Valley	3.1	-2.8
350010032	Westside	1.1	-3.4
350011012	Foot Hills	13.6	2.0
350130008	La Union	17.4	-1.6
350130017	Sunland Park Yard	9.0	-3.6
350130020	Chaparral	4.8	-4.7
350130021	Desert View	3.2	-5.1
350130022	Santa Teresa	8.2	0.1
350130023	Solano	6.1	-6.5
350151005	Carlsbad	-1.1	-12.3
350171003	Chino Copper	9.1	-1.0
350250008	Hobbs Jefferson	2.1	-9.9
350290003	Deming Airport	6.2	-5.0
350390026	Coyote Ranger	3.3	-5.4
350431001	Bernalillo	8.1	3.8
350450009	Bloomfield	7.2	2.5
350450018	Navajo Lake	2.2	-0.6
350451005	Sub Station	1.4	3.3
350490021	Santa Fe Airport	3.8	-1.7
350610008	Los Lunas	0.8	-6.5

Table 6-6. Bias MDA8 ozone performance statistics with and without an observed ozone cutoff for each site in New Mexico and the revised CAMx 2014v2 base case simulation.

2014v2 (with BEIS)			
SiteID	SiteNames	NMB No Cutoff	NMB 60 ppb Cutoff
350010023	Del Norte	0.5	-4.9
350010024	South East Heights	1.3	-3.6
350010029	South Valley	0.9	-4.4
350010032	Westside	-1.0	-5.4
350011012	Foot Hills	11.9	0.8
350130008	La Union	15.0	-3.0
350130017	Sunland Park Yard	7.4	-4.1
350130020	Chaparral	2.8	-5.8
350130021	Desert View	1.4	-6.3
350130022	Santa Teresa	5.8	-1.8
350130023	Solano	3.9	-8.2
350151005	Carlsbad	-4.3	-14.5
350171003	Chino Copper	7.0	-1.8
350250008	Hobbs Jefferson	-1.2	-12.6
350290003	Deming Airport	3.8	-8.6
350390026	Coyote Ranger	1.2	-5.6
350431001	Bernalillo	6.4	3.3
350450009	Bloomfield	6.0	1.7
350450018	Navajo Lake	0.5	-3.6
350451005	Sub Station	-0.1	2.2
350490021	Santa Fe Airport	1.5	-2.5
350610008	Los Lunas	-1.7	-9.0

6.7 Conclusions of 2014 Base Case Modeling and Model Performance Evaluation

The evaluation of the NM OAI Study CAMx original 2014 and revised 2014v2 base case simulations focused on MDA8 ozone model performance across all sites within New Mexico, within three subregions in New Mexico (northern, Bernalillo County, and southern) and at individual sites in New Mexico. When examining MDA8 ozone performance across groups of sites, both CAMx 2014 base cases always achieves the ozone Performance Criteria and usually achieves the ozone Performance Goals. Except for one site (La Union in Doña Ana County) both CAMx base cases also achieve the ozone Performance Criteria at all monitoring sites and achieve the ozone Performance Goals as a majority of the sites in New Mexico. When examining MDA8 ozone performance across all observations, the model tended to have an ozone overestimation tendency but still always achieved the bias performance criteria ($\leq \pm 15\%$) and usually achieved the bias performance goal ($\leq \pm 5\%$). When comparing the model's ability to reproduce the highest observed ozone concentrations greater than 60 ppb, the model still always achieved the bias performance criteria and usually achieved the bias performance goal, albeit with an underestimation tendency. The

MDA8 ozone error essentially always achieves the performance goal whether examining all ozone observations or just those observations greater than 60 ppb.

In conclusion, the NM OAI Study original CAMx 2014 and revised CAMx 2014v2 base case simulations ozone model performance within New Mexico is as good or better than most recent PGM applications (e.g., WRAP-WAQS, EPA 2016v1 and Denver ozone SIP) and appears to be a reliable PGM modeling platform for evaluating emission reduction strategies for reducing ozone concentrations in New Mexico.

7. 2028 BASE CASE MODELING AND OZONE DESIGN VALUE PROJECTIONS

A CAMx v7.1 2028 36/12/4-km Base Case model simulation was conducted using the WRF/NAM meteorological, 2014 Boundary Conditions (BCs) and 2028 base case emission inputs described in, respectively, Chapters 2, 3 and 4. The CAMx 2028 base case simulation used the same model configuration as used in the CAMx v7.1 2014v2 revised base case simulations presented in Chapter 6 only with the 2028 Base Case anthropogenic emissions.

The CAMx 2014v2 and 2028 Base Case simulations were used to make 2028 future-year ozone design value (DVF) projections.

7.1 EPA Recommended Ozone Design Value Projection Procedure

EPA recommends using photochemical grid model (PGM) modeling results in a relative fashion to scale the observed current year ozone design value (DVC) to estimate the future year ozone design value (DVF). The model derived scaling factors are called Relative Response Factors (RRF) and are the ratio of future (2028) to base (2014v2) year ozone modeling results averaged over the 10 highest base year base case modeled Maximum Daily 8-hour Average (MDA8) ozone concentrations near the monitor:

$$RRF = \sum \text{Model}_{2028} / \sum \text{Model}_{2014}$$

$$DVF = DVC \times RRF$$

EPA guidance recommends that the DVC is calculated as the average of three-years of ozone design values (DV) centered on the base modeling year, which is 2014 in this case:

$$DVC_{2012-2016} = (DV_{2012-2014} + DV_{2013-2015} + DV_{2014-2016}) / 3$$

By near the monitor, EPA guidance recommends that the highest modeled base year MDA8 ozone is selected within a 3x3 array of grid cells centered on the monitor. For the future year, the future year MDA8 ozone is selected from the same grid cell in the 3x3 array centered on the monitor as used in the base year.

EPA guidance recommends using the 10 highest modeled base year MDA8 ozone concentrations days with MDA8 ozone greater than 60 ppb in the RRFs. If there are less than 10 modeled days with base year MDA8 ozone greater than 60 ppb, EPA guidance states that RRFs can still be calculated as long as there are at least 5 days with ozone greater than 60 ppb.

EPA has codified their recommended ozone DVF projection approach in the Software for the Modeled Attainment Test (SMAT³⁷). The SMAT tool was used to make 2028 ozone DVF projections in the NM OAI Study. The default SMAT specification were used except

³⁷ <https://www.epa.gov/scram/photochemical-modeling-tools>

that the minimum number of days needed to calculate an RRF was lowered from 5 to 4 in order to obtain 2028 ozone DV projections at all sites in New Mexico.

7.1.1 Ozone DV Unmonitored Area Analysis (UAA)

SMAT includes an unmonitored area analysis (UAA) that examines projected future year ozone DVFs away from the monitoring sites. The first step in the UAA is the spatial interpolation of the monitor-based ozone DVCs (DVC₂₀₁₂₋₂₀₁₆) across the domain being analyzed, which is the 4-km New Mexico domain in this case. The SMAT spatial interpolation of the monitoring site ozone DVC can be performed with and without using the modeled ozone concentration gradients. As shown below, the SMAT UAA analysis was run for the NM OAI Study 2028 base case ozone DVC projections with and without using the modeled concentration gradients. We recommend using the interpolation without the modeled concentration gradients because of the influence of fires on UAA interpolated ozone DVCs that are uncertain, unverifiable, and not regulatory relevant.

The SMAT UAA procedure for projecting the spatially interpolated ozone DVCs is the same as used at the monitor described above, only instead of using the modeling results in the in a 3x3 array of grid cells with the highest 2014 modeled MDA8 ozone to define near the monitor, the value at the grid cell is used (i.e., 1x1 array).

7.2 2028 Base Case Ozone DVF Projections at Monitoring Sites

Table 7-1 displays the current year DVC₂₀₁₂₋₂₀₁₆ and projected 2028 ozone DVFs at monitoring sites in New Mexico for the 2028 Base Case simulation and their differences. There are two sites in Doña Ana County with current year DVC₂₀₁₂₋₂₀₁₆ above the 70 ppb 2015 ozone NAAQS, Desert View (72.0 ppb) and Santa Teresa (71.3 ppb). However, it should be noted that measured ozone concentrations in Southern New Mexico have been higher in more recent years, as shown in Table 1-1. This issue is examined in a DVC sensitivity analysis presented in Chapter 9.

The 2028 Base Case ozone DVFs at monitoring sites in northern New Mexico are projected to be -2.2 ppb to -5.6 ppb lower than the observed DVC₂₀₁₂₋₂₀₁₆. For the northern New Mexico sites, Navajo Lake has the highest ozone DVC₂₀₁₂₋₂₀₁₆ (67.0 ppb) and 2028 Base Case projected DVF (64.8) and is the site with the lowest reduction between the DVC and DVF (-2.2 ppb).

The current observed DVC₂₀₁₂₋₂₀₁₆ in Bernalillo County range from 65.0 to 68.0 ppb and are projected to be reduced by -4.4 ppb to -5.9 ppb by 2028 with all 2028 Base Case projected ozone DVFs in Bernalillo County below 63 ppb.

The current ozone DVC₂₀₁₂₋₂₀₁₆ at the southern New Mexico sites range from 62.0 to 72.0 ppb and are reduced by -2.0 ppb to -6.3 ppb in the 2028 Base Case. The sites in Doña Ana County have the largest ozone DV reductions between 2014 and 2028 (-4.7 to -6.3 ppb). While those monitoring sites in southeast New Mexico have the lowest ozone DVF reduction between 2014 and 2028 Base Cases, -2.3 ppb at Carlsbad and -2.0 ppb at Hobbs in, respectively, Eddy and Lea Counties. The lower reductions in 2028 Base Case ozone DVFs at the two southeastern New Mexico sites are due to increased oil and gas emissions in the Permian Basin between 2014 and 2028 that offset the effects due to emission reductions from other source sectors, such as mobile sources (see Chapter 4).

Table 7-1. Current year DVC₂₀₁₂₋₂₀₁₆ and projected 2028 Base Case ozone DVCs at New Mexico monitoring sites within the 4-km NM domain.

AQS_ID	2012-2016 DVC (ppb)	2028 Base DVC Base (ppb)	Difference 2028 DVC minus DVC ₂₀₁₂₋₁₆ (ppb)	Site Name	State	County
Northern New Mexico						
350390026	64.0	60.8	-3.2	Coyote Ranger District	NM	Rio Arriba
350431001	64.0	58.4	-5.6	Bernalillo (E Avenida)	NM	Sandoval
350450009	64.3	61.0	-3.3	Bloomfield	NM	San Juan
350450018	67.0	64.8	-2.2	Navajo Lake	NM	San Juan
350451005	63.7	60.8	-2.9	Substation	NM	San Juan
350490021	64.3	60.6	-3.7	Santa Fe Airport	NM	Santa Fe
Bernalillo County						
350010023	66.3	60.9	-5.4	Del Norte HS	NM	Bernalillo
350010024	68.0	62.3	-5.7	South East Heights	NM	Bernalillo
350010029	66.0	61.0	-5.0	South Valley	NM	Bernalillo
350010032	67.0	62.6	-4.4	Westside	NM	Bernalillo
350011012	65.0	59.1	-5.9	Foothills	NM	Bernalillo
Southern New Mexico						
350130008	66.3	60.0	-6.3	La Union	NM	Doña Ana
350130017	67.0	61.9	-5.1	Sunland Park City Yard	NM	Doña Ana
350130020	67.0	62.3	-4.7	Chaparral	NM	Doña Ana
350130021	72.0	67.0	-5.0	Desert View	NM	Doña Ana
350130022	71.3	66.1	-5.2	Santa Teresa	NM	Doña Ana
350130023	65.0	60.3	-4.7	Solano	NM	Doña Ana
350151005	69.0	66.7	-2.3	Carlsbad	NM	Eddy
350171003	62.0	59.0	-3.0	Chino Copper Smelter	NM	Grant
350250008	66.0	64.0	-2.0	Hobbs Jefferson	NM	Lea
350290003	66.0	62.7	-3.3	Deming Airport	NM	Luna
350610008	66.3	62.2	-4.1	Los Lunas (Los Lentos)	NM	Valencia

The current year DVC₂₀₁₂₋₂₀₁₆ and projected 2028 Base Case ozone DVFs at monitoring sites within the 4-km NM domain but outside of New Mexico are shown in Table 7-2. The El Paso UTEP site is the only site in Table 7-2 that has a DVC₂₀₁₂₋₂₀₁₆ that exceeds (71.0 ppb) the 2015 ozone NAAQS. Design values at monitoring sites in El Paso are projected to go down between -3.2 ppb to -5.2 ppb with projected 2028 Base Case ozone DVFs ranging from 62.5 ppb to 66.2 ppb.

The sites in Arizona and Colorado have current year DVC₂₀₁₂₋₂₀₁₆ that are 68 ppb or lower and are reduced from -1.6 ppb to -5.2 ppb with the smallest reductions occurring in La Plata County, Colorado and the largest reductions occurring in El Paso.

Table 7-2. Current year DVC₂₀₁₂₋₂₀₁₆ and projected 2028 Base Case ozone DVFs at monitoring sites within the 4-km NM domain but outside of New Mexico.

AQS_ID	2012-2016 DVC (ppb)	2028 Base DVF Base (ppb)	Difference 2028 DVF minus DVC ₂₀₁₂₋₁₆ (ppb)	Site Name	State	County
Arizona, Colorado and Texas						
40038001	68.0	64.0	-4.0	Chiricahua NM	AZ	Cochise
40170119	66.7	61.9	-4.8	Petrified Forest	AZ	Navajo
80677001	67.7	66.1	-1.6	UTE 1	CO	La Plata
80677003	66.7	64.4	-2.3	UTE 3	CO	La Plata
80830006	63.0	59.7	-3.3	Cortez - Health Dept	CO	Montezuma
80830101	66.0	62.4	-3.6	Mesa Verde NP	CO	Montezuma
481410029	61.0	58.0	-3.0	Ivanhoe	TX	El Paso
481410037	71.0	66.2	-4.8	El Paso UTEP	TX	El Paso
481410044	67.7	62.5	-5.2	El Paso Chamizal	TX	El Paso
481410055	62.7	59.2	-3.5	Ascarate Park SE	TX	El Paso
481410057	66.5	63.3	-3.2	Socorro Hueco	TX	El Paso
481410058	68.0	63.4	-4.6	Skyline Park	TX	El Paso
483819991	66.7	62.4	-4.3	Palo Duro	TX	Randall

7.3 2028 Base Case Ozone DVF Unmonitored Area Analysis

SMAT was run using output the 2014v2 and 2028 Base Case CAMx simulations to obtain the spatial distribution of interpolated current year ozone DVC₂₀₁₂₋₂₀₁₆ and projected 2028 ozone DVF throughout the 4-km NM domain using the Unmonitored Area Analysis (UAA) feature. SMAT UAA was run with and without using modeled concentration gradients in the spatial interpolation of the observed ozone DVC₂₀₁₂₋₂₀₁₆ at the monitoring sites to each grid cell in the 4-km NM domain.

Figure 7-1 displays the spatial distribution of the SMAT UAA ozone DVC₂₀₁₂₋₂₀₁₆ and DVF across the 4-km NM domain calculated using CAMx modeled ozone concentrations gradients in the spatial interpolation of the DVC₂₀₁₂₋₂₀₁₆. Although the highest DVC₂₀₁₂₋₂₀₁₆ at a monitoring site is 72.0 ppb at Desert View, using modeled concentration

gradients produces an interpolated $DVC_{2012-2016}$ as high as 89.5 ppb that occurs in Arizona on the border with New Mexico that is reduced to 84.0 ppb for the maximum 2028 Base Case UAA DVF. These high MDA8 ozone concentrations in eastern Arizona and southwestern New Mexico are due to elevated ozone concentrations from wildfire emissions that are used in the SMAT UAA $DVC_{2012-2016}$ spatial interpolation when the option to use modeled concentration gradients is selected. Because they occur away from any monitoring sites, whether actual elevated ozone occurred in these wildfire ozone plumes is not known. Away from these wildfire ozone plumes, the SMAT UAA $DVC_{2012-2016}$ range from 60 to 71 ppb that are reduced to the 50 to 65 ppb range in for the SMAT UAA 2028 ozone DVF with small patches in the 65-71 ppb range scattered across New Mexico.

The SMAT UAA ozone $DVC_{2012-2016}$ and 2028 Base Case projections obtained without using the modeled concentrations gradients are shown in Figure 7-2. When doing the SMAT UAA spatial interpolation of the $DVC_{2012-2016}$ without including the concentrations gradients the ozone $DVC_{2012-2016}$ across the 4-km NM modeling domain are constrained by the $DVC_{2012-2016}$ values at the monitoring sites (i.e., Tables 7-1 and 7-2), which range from 61.4 to 71.0 ppb (10 ppb range; Figure 7-2). This is in contrast when the modeled concentrations gradients are used in the SMAT UAA interpolation and the $DVC_{2012-2016}$ range from 58.2 to 89.5 ppb across the domain (31 ppb range; Figure 7-1).

Figure 7-3 displays a spatial map of the differences in ozone $DVC_{2012-2016}$ and 2028 base case DVF ($DVF - DVC$) from the SMAT UAA with the top panel shown the differences with and the bottom panel showing the differences without using the modeled spatial gradients in the interpolation. Using the modeled concentration gradients in the interpolation has a significant effect on the DVC/DVFs, but has little effect on the differences in the SMAT UAA DVF and DVC. In fact, the only perceptible change in the ozone DVF and DVC differences is near the location of the modeled wildfire ozone plume in eastern Arizona.

The largest differences in current year ozone DVC and the 2028 Base Case DVF occurs in the eastern part of the domain with reductions of -4 to -11 ppb that are coming in from east Texas where there are larger emission reductions due to larger population centers. Over most of New Mexico, there are small reductions in the -1 to -4 ppb range with reductions in the -4 to -6 ppb range near Albuquerque. However, within the Permian and San Juan Basins there are small areas of ozone DVF increases with the largest increase of +3 ppb.

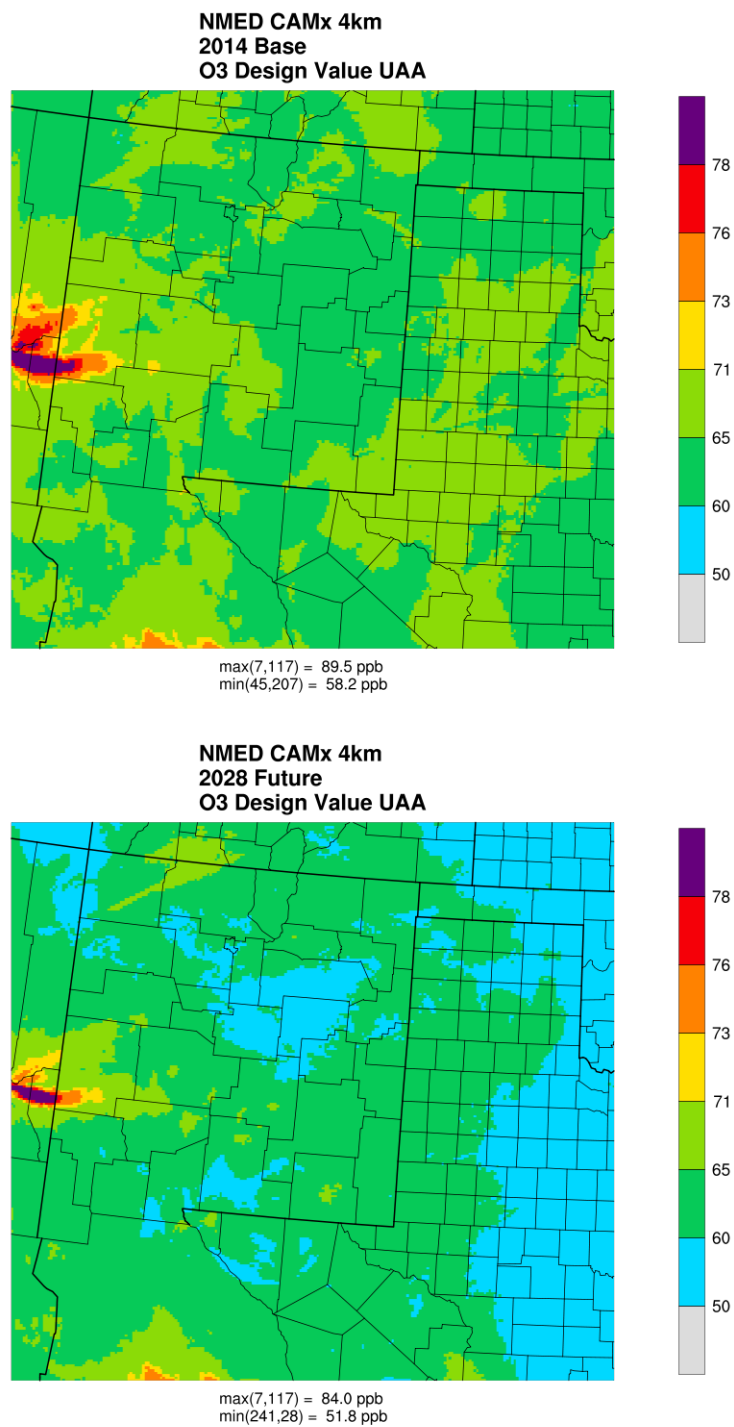


Figure 7-1. SMAT UAA current year ozone DVC₂₀₁₂₋₂₀₁₆ and projected 2028 future year ozone DVF for the 2028 Base Case using spatial interpolation with concentration gradients.

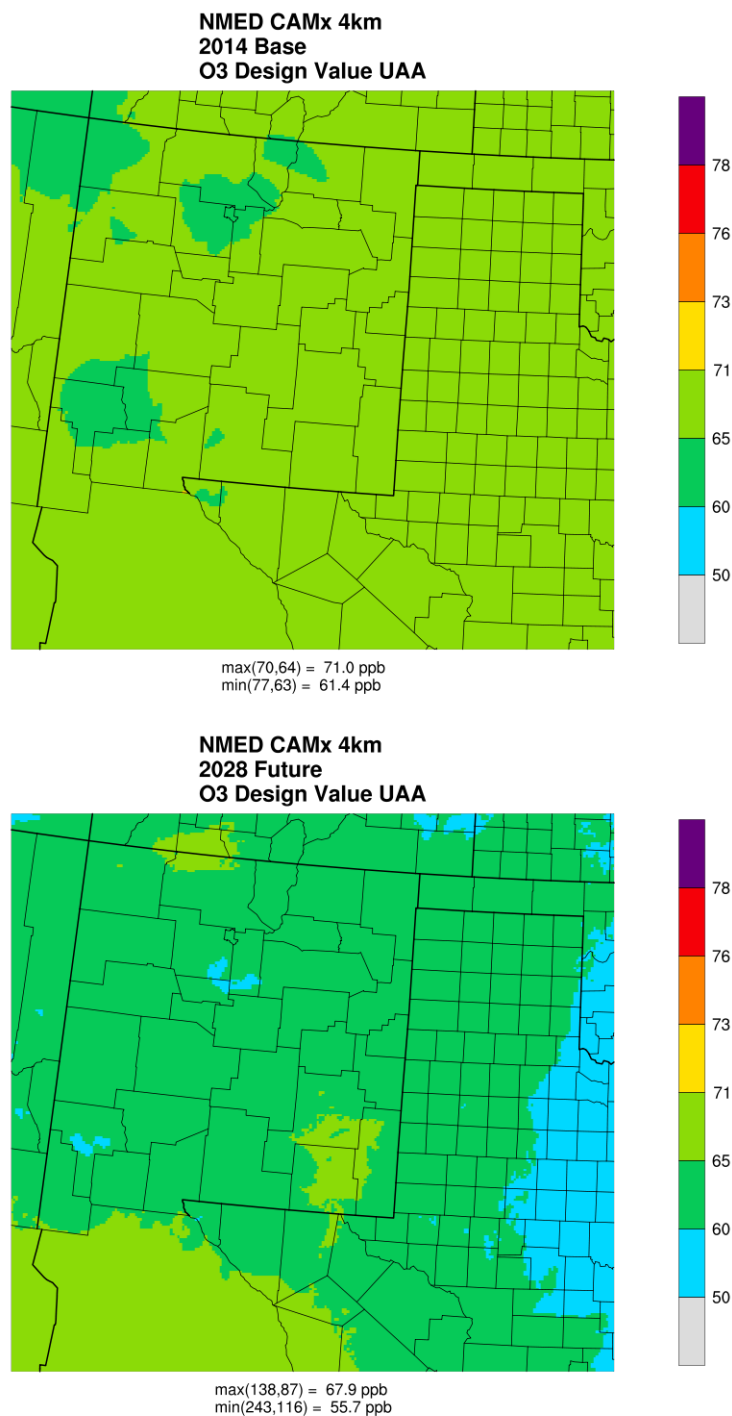


Figure 7-2. SMAT UAA current year ozone DVC₂₀₁₂₋₂₀₁₆ (top) and projected 2028 future year DVF for the 2028 Base Case using spatial interpolation without concentration gradients.

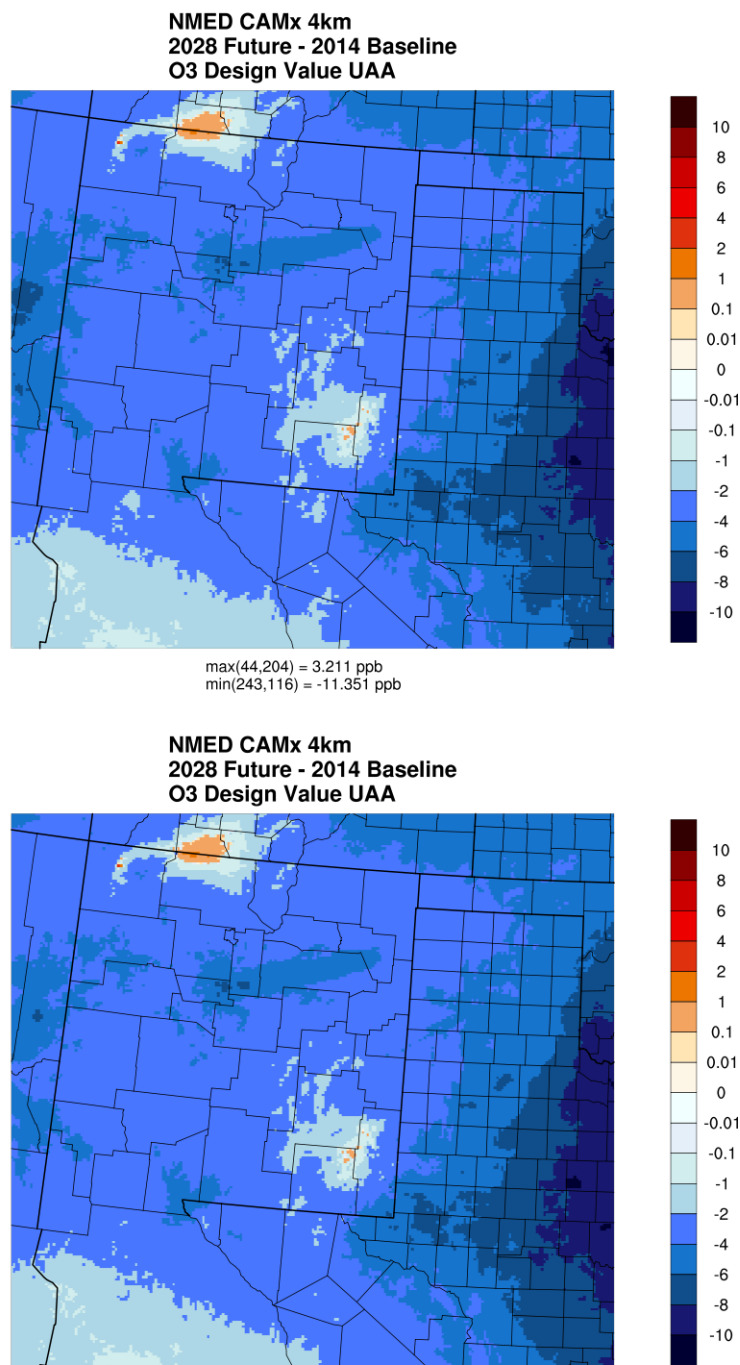


Figure 7-3. Differences between SMAT UAA current year ozone DVC₂₀₁₂₋₂₀₁₆ and projected 2028 future year ozone DVF for the 2028 Base Case using spatial interpolation with (top) and without (bottom) concentration gradients.

7.4 2014v2 and 2028 MDA8 Ozone Concentrations

In this section we present spatial maps of daily MDA8 ozone and the differences in MDA8 ozone for the 2014v2 and 2028 Base Case CAMx simulations for six example days. MDA8 ozone concentration and difference plots were generated for all ~100 days of the modeling episode, most of which were fairly low ozone concentration days so are of less interest.

7.4.1 Daily 2014v2 and 2028 Base Case MDA8 Ozone Concentrations

Figures 7-4 through 7-9 display example spatial maps of MDA8 ozone concentrations for the CAMx 2014v2 and 2028 Base Case simulations and their differences for six example days.

The most prominent features in the estimated MDA8 ozone concentrations on May 17, 2014 are locations of very high (> 80 ppb) ozone concentrations in eastern Arizona and southwest New Mexico (Figure 7-4). These high ozone concentrations have a signature of ozone from wildfires with the largest being an ozone plume being transported into western New Mexico from a wildfire in eastern Arizona. Although there are no ozone monitors located in the center of these model-estimated highly elevated ozone plumes, the Chino Copper Smelter site in Grant County is within the edge of the plume where the model estimates MDA8 ozone concentrations in the 65-71 ppb range that match the observed concentrations at this site extremely well for the May-June 2014 portion of the episode (see Appendix A in Ramboll and WESTAR, 2020c; 2021). Over most of New Mexico, the 2028 Base Case has lower MDA8 ozone concentrations with reductions as high as -11 ppb in southwest Torrance County. However, the 2028 Base Case has MDA8 ozone increases in the San Juan and Permian Basins with a maximum MDA8 ozone increase of +5 ppb in Eddy County.

On June 5, 2014, the 2014v2 Base Case has CAMx-estimated MDA8 ozone concentrations in the 65-71 ppb range in northwest New Mexico and in Doña Ana County with even a small location of MDA8 ozone exceeding the 2015 ozone NAAQS in the northeast corner of San Juan County and a modeled peak MDA8 ozone concentration of 72.9 ppb occurring in El Paso just over the border from Doña Ana County (Figure 7-5). Although the emission changes from 2014v2 to 2028 reduce the intrusion of elevated ozone entering Doña Ana County from El Paso, the elevated ozone in northwest New Mexico is increased. The area of estimated MDA8 ozone in San Juan County that is above the 2015 ozone NAAQS is larger in the 2028 Base Case than the 2014v2 Base Case and stretches into Rio Arriba County with a peak ozone value of 74 ppb in Colorado at the border with New Mexico. As shown in the MDA8 ozone difference plot in Figure 7-5, increases in MDA8 ozone concentrations in the 2028 Base Case are due to increased O&G emissions within the Permian and San Juan Basins.

Although the 2014v2 and 2028 Base Case estimated MDA8 ozone on July 12, 2014 is well below the NAAQS (mostly < 60 ppb with small pockets in the 60-65 ppb range), the 2028 Base Case has increases MDA8 ozone in the San Juan and Permian Basins with a maximum increase of +11.4 ppb (Figure 7-6). The maximum decrease in MDA8 ozone is -7.6 ppb near Albuquerque.

On July 24, 2014, the CAMx 2014v2 Base Case estimates elevated MDA8 ozone concentrations in northwest New Mexico with values even exceeding the 2015 ozone

NAAQS in San Juan County and a peak value of 74.7 ppb in Colorado at the border with New Mexico (Figure 7-7). The 2028 Base Case has lower ozone than the 2014v2 Base Case across New Mexico with only small areas of ozone increases. The area of MDA8 ozone in San Juan County that was above the 2015 ozone NAAQS in the 2014v2 Base Case is reduced to below the NAAQS in the 2028 Base Case, although the peak MDA8 ozone in Colorado at the border of New Mexico still exceeds the NAAQS (71.3 ppb).

The CAMx 2014v2 Base Case estimates a high peak MDA8 ozone concentration of 78.4 ppb in Albuquerque with several additional areas of high ozone above the NAAQS occurring in other northern New Mexico Counties on July 26, 2014 (Figure 7-8). Although the 2028 Base Case has reduced almost all of the areas with 2014v2 MDA8 ozone above the NAAQS, there is still an estimate ozone peak above the NAAQS (72.3 ppb) just west of Albuquerque in northeast Cibola County. Ozone increases are seen in the Permian and San Juan Basins on July 26 with the highest increase of +5.7 ppb occurring in the San Juan Basin.

An ozone peak of 74.1 ppb occurs on August 14 on the border of Doña Ana County and El Paso with ozone in excess of the NAAQS stretching into Doña County (Figure 7-9). The emission reductions in the 2028 Base Case appear reduce the estimated ozone in Doña County to below the NAAQS, although the peak ozone (71.2 ppb) just over the border in El Paso still exceeds the NAAQS. Ozone increases in the Permian and San Juan Basins are mostly less than +1 ppb and fairly isolated on this day.

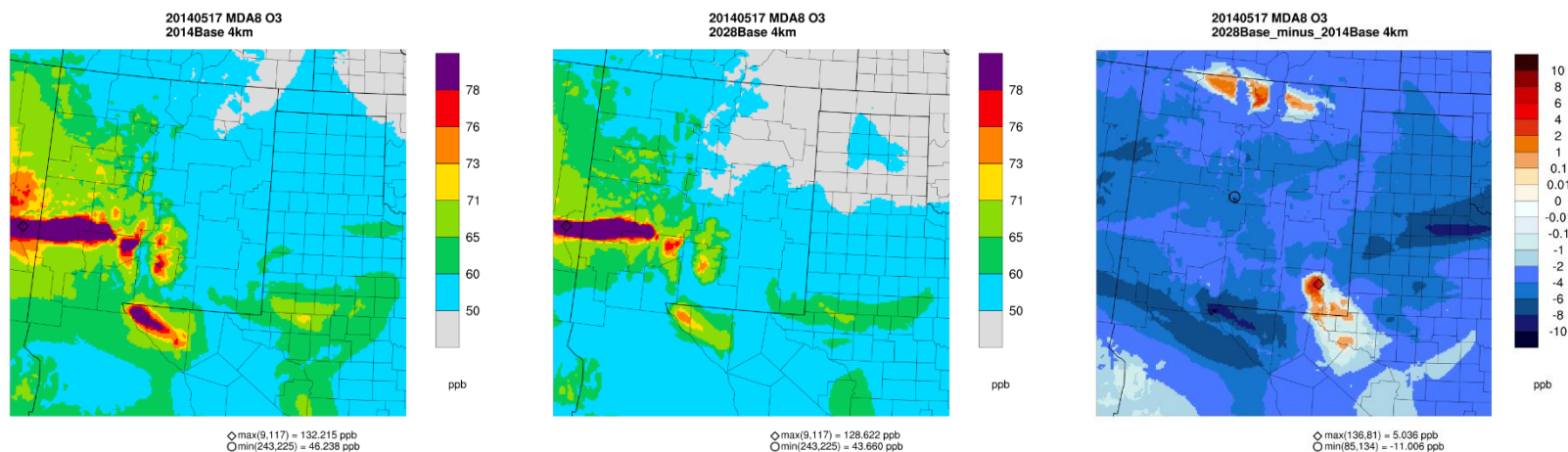


Figure 7-4. CAMx estimated MDA8 ozone concentrations (ppb) on May 17, 2014 for the 2014v2 Base Case (left), 2028 Base Case (middle) and their difference (right).

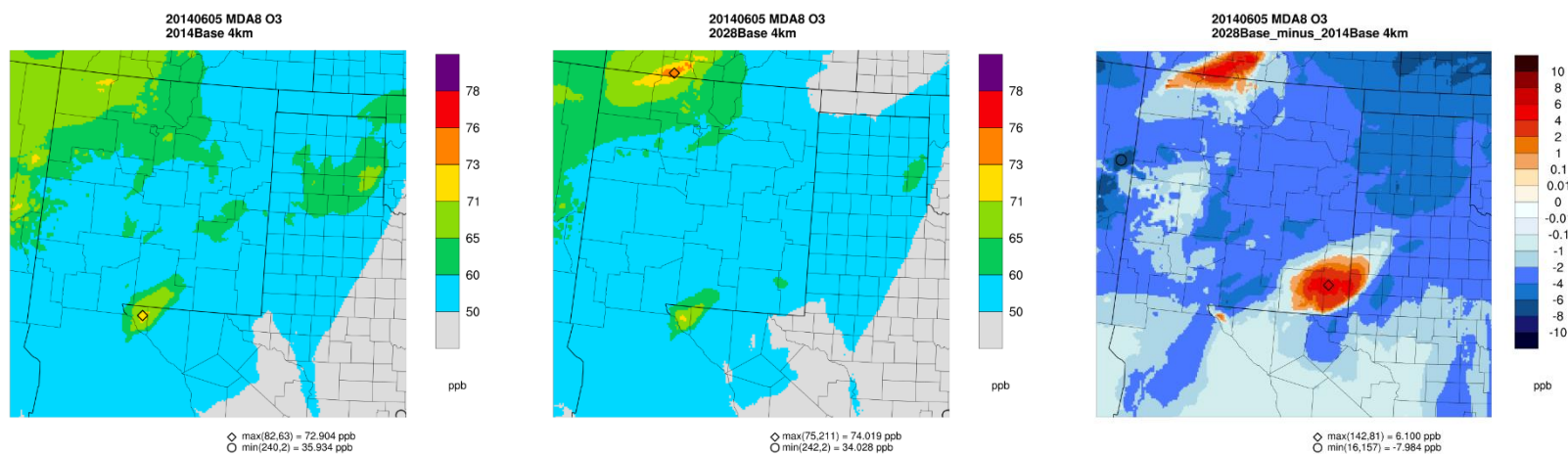


Figure 7-5. CAMx estimated MDA8 ozone concentrations (ppb) on June 5, 2014 for the 2014v2 Base Case (left), 2028 Base Case (middle) and their difference (right).

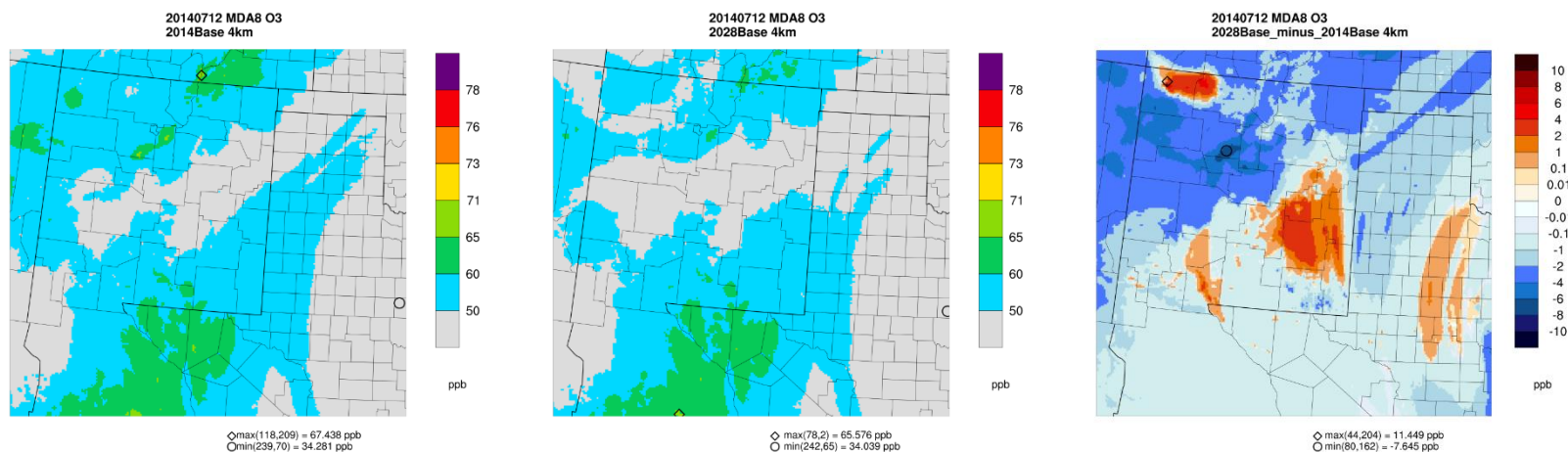


Figure 7-6. CAMx estimated MDA8 ozone concentrations (ppb) on July 12, 2014 for the 2014v2 Base Case (left), 2028 Base Case (middle) and their difference (right).

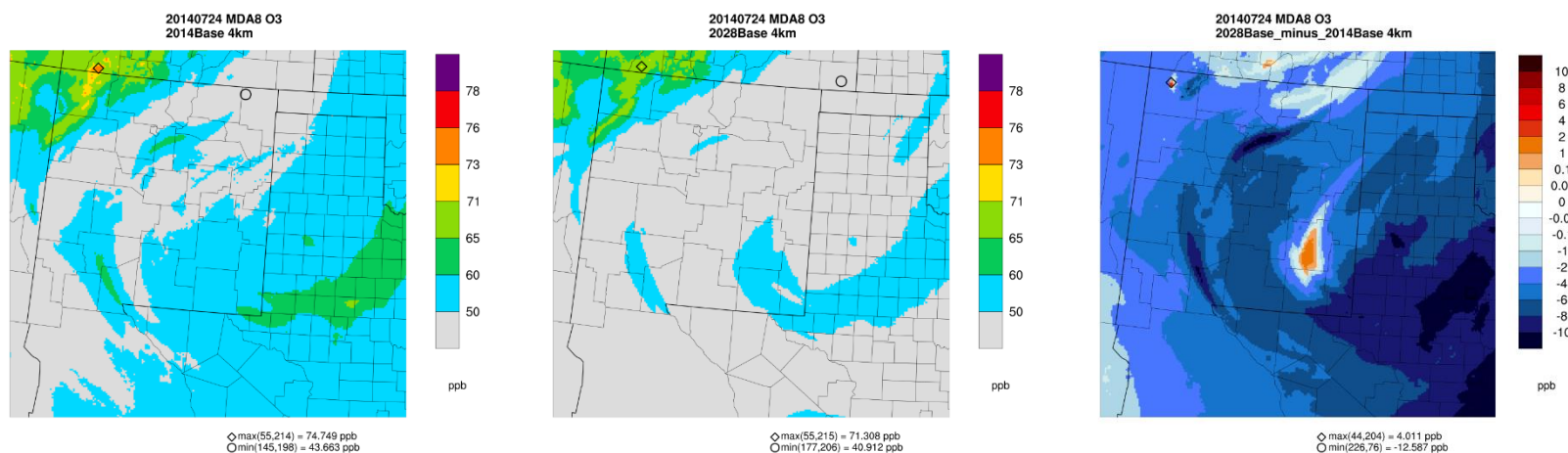


Figure 7-7. CAMx estimated MDA8 ozone concentrations (ppb) on July 24, 2014 for the 2014v2 Base Case (left), 2028 Base Case (middle) and their difference (right).

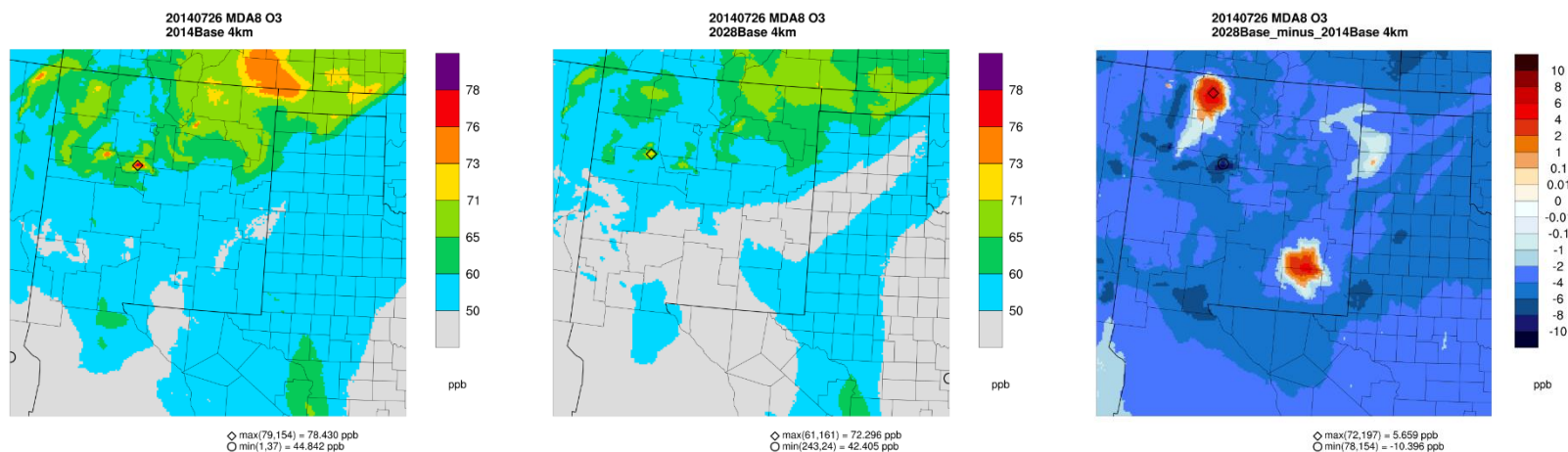


Figure 7-8. CAMx estimated MDA8 ozone concentrations (ppb) on July 26, 2014 for the 2014v2 Base Case (left), 2028 Base Case (middle) and their difference (right).

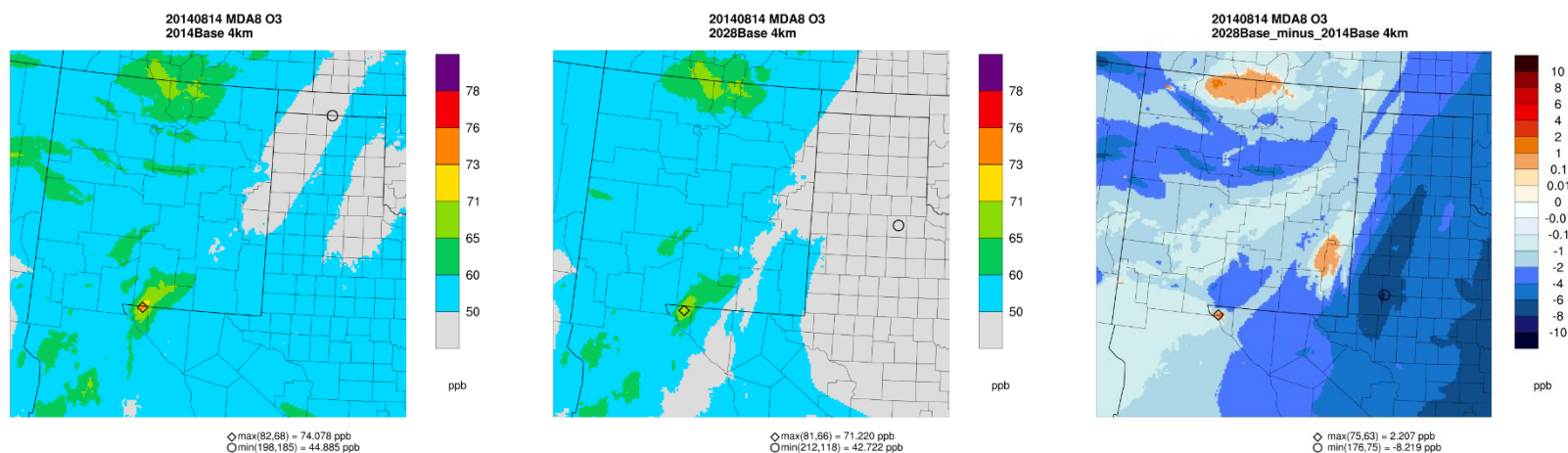


Figure 7-9. CAMx estimated MDA8 ozone concentrations (ppb) on August 14, 2014 for the 2014v2 Base Case (left), 2028 Base Case (middle) and their difference (right).

7.4.2 Comparison of Episode Maximum MDA8 and SMAT UAA Ozone DVF Differences

Figure 7-10 compare the differences in episode maximum MDA8 ozone concentrations and SMAT UAA ozone DVs between the 2014v2 and 2028 Base Case simulations (the SMAT UAA ozone DV differences are without using concentration gradients and was shown previously in the bottom panel of Figure 7-3). Not surprisingly, since the SMAT UAA DVs represents an average across several modeling days, the episode maximum MDA8 ozone differences have higher changes than the SMAT UAA ozone differences with a maximum increase of +5 ppb vs. +3 ppb and maximum decrease of -12 ppb vs. -11 ppb for the, respectively, episode maximum MDA8 ozone and UAA DVs. The largest decreases occur in Albuquerque and in southern Doña Ana County on the border with El Paso. The largest increases in ozone occur in the San Juan and Permian Basin.

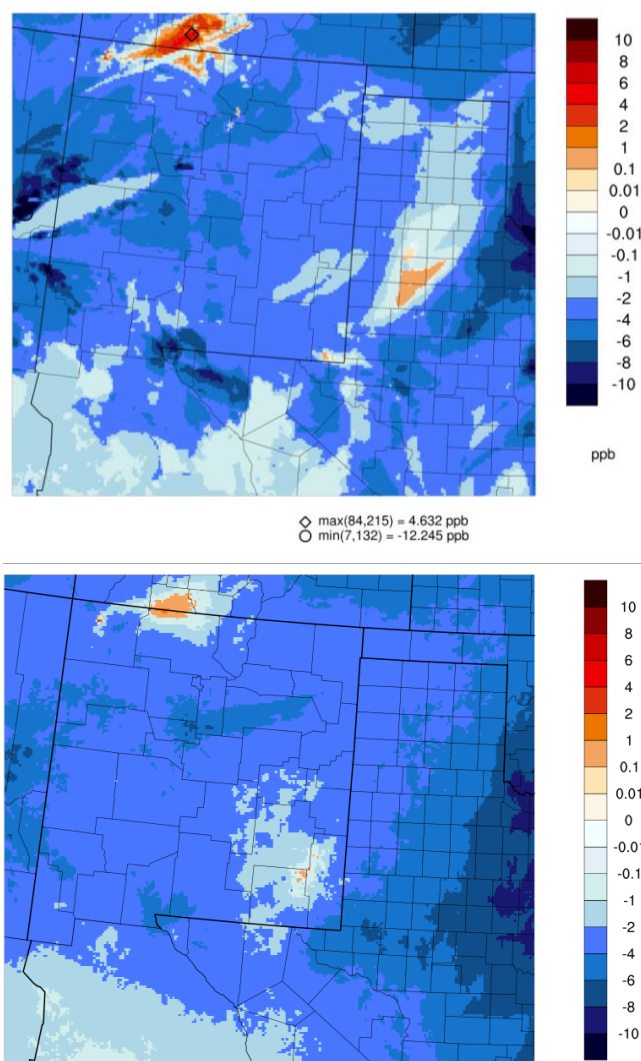


Figure 7-10. Differences in episode maximum MDA8 ozone concentrations (top) and SMAT UAA ozone DVs (bottom) between the 2014v2 and 2028 CAMx Base Case simulations.

8. 2028 OIL AND GAS CONTROL STRATEGY MODELING AND OZONE DESIGN VALUE PROJECTIONS

The implementation of the proposed New Mexico oil and gas (O&G) ozone precursor control strategy reduces VOC and NO_x emissions in the New Mexico portions of the San Juan and Permian Basins, as discussed in Section 4.5. Most of the O&G emission reduction in the San Juan Basin occur in northeastern San Juan and northwestern Rio Arriba Counties. While most of the emission reductions in the Permian Basin occur in Eddy and Lea Counties.

8.1 2028 Ozone Design Value Comparisons

The same procedures as used to project 2028 ozone DVFs for the CAMx 2028 Base Case (DVF_{Base}) were used to project the 2028 ozone DVFs for the 2028 O&G Control Strategy scenario (DVF_{Cntl}). These procedures start with an observed current year design value that is an average of 3 design values over 5-years (DVC₂₀₁₂₋₂₀₁₆) that is scaled by Relative Response Factors (RRFs) based on the ratio of the 2028 O&G Control Strategy over the 2014v2 Base Case CAMx ozone results to obtained a projected 2028 ozone DVF_{Cntl} for the 2028 O&G Control Strategy.

8.1.1 Ozone Design Values at the Monitoring Sites

Table 8-1 list the current year ozone DVC₂₀₁₂₋₂₀₁₆ and the projected 2028 ozone DVFs for the 2028 Base Case and 2028 O&G Control Strategy and the differences in the two 2028 ozone DVFs (DVF_{Cntl} – DVF_{Base}).

At monitoring sites in northern New Mexico, the 2028 ozone DVF_{Base} values are estimated to be reduced by -0.2 to -1.5 ppb due to the 2028 O&G Control Strategy with the largest reductions occurring at the Navajo Lake (-1.5 ppb) and Substation (-1.2 ppb) monitoring sites in San Juan County. After implementation of the 2028 O&G Control Strategy, the projected 2028 ozone DVF_{Cntl} in northern New Mexico range from 58.1 to 63.3 ppb.

Although not as close to the 2028 O&G emission reductions, the 2028 projected ozone DVF_{Cntl} in Bernalillo County see benefits of the 2028 O&G Control Strategy with ozone DVF reductions of -0.2 to -0.5 ppb. After implementation of the 2028 O&G Control Strategy, the projected 2028 ozone DVF_{Cntl} range from 58.8 to 62.1 ppb in Bernalillo County.

The 2028 ozone DVF reductions due to the 2028 O&G Control Strategy at the southern New Mexico monitoring sites range from -0.2 to -0.7 ppb with the largest reductions occurring at the Hobbs (-0.7 ppb) and Carlsbad (-0.3 ppb) monitoring sites in, respectively, Eddy and Lea Counties that lie within the Permian Basin. The other monitoring sites in southern New Mexico are farther away from the Permian Basin so have much more modest reductions in ozone DVFs (-0.1 to -0.2 ppb) due to the controls on oil and gas sources. After implementation of the 2028 O&G Control Strategies, the projected 2028 ozone DVF_{Cntl} at southern New Mexico sites range from 58.9 ppb to 66.8 ppb.

Table 8-1. Observed ozone DVC₂₀₁₂₋₂₀₁₆ and projected 2028 ozone DVFs for the 2028 Base Case and 2028 O&G Control strategy and differences in the 2028 ozone DVFs (DVF_{Cntl} – DVF_{Base}).

AQS_ID	2012-16	Projected 2028 DVF			Site Name	State	County
	DVC (ppb)	Base (ppb)	Cntl (ppb)	Cntl - Base			
Northern New Mexico							
350390026	64.0	60.8	60.0	-0.8	Coyote Ranger District	NM	Rio Arriba
350431001	64.0	58.4	58.1	-0.3	Bernalillo (E Avenida)	NM	Sandoval
350450009	64.3	61.0	60.2	-0.8	Bloomfield	NM	San Juan
350450018	67.0	64.8	63.3	-1.5	Navajo Lake	NM	San Juan
350451005	63.7	60.8	59.6	-1.2	Substation	NM	San Juan
350490021	64.3	60.6	60.4	-0.2	Santa Fe Airport	NM	Santa Fe
Bernalillo County							
350010023	66.3	60.9	60.7	-0.2	Del Norte HS	NM	Bernalillo
350010024	68.0	62.3	62.0	-0.3	South East Heights	NM	Bernalillo
350010029	66.0	61.0	60.5	-0.5	South Valley	NM	Bernalillo
350010032	67.0	62.6	62.1	-0.5	Westside	NM	Bernalillo
350011012	65.0	59.1	58.8	-0.3	Foothills	NM	Bernalillo
Southern New Mexico							
350130008	66.3	60.0	59.8	-0.2	La Union	NM	Doña Ana
350130017	67.0	61.9	61.8	-0.1	Sunland Park City Yard	NM	Doña Ana
350130020	67.0	62.3	62.2	-0.1	Chaparral	NM	Doña Ana
350130021	72.0	67.0	66.8	-0.2	Desert View	NM	Doña Ana
350130022	71.3	66.1	66.0	-0.1	Santa Teresa	NM	Doña Ana
350130023	65.0	60.3	60.2	-0.1	Solano	NM	Doña Ana
350151005	69.0	66.7	66.4	-0.3	Carlsbad	NM	Eddy
350171003	62.0	59.0	58.9	-0.1	Chino Copper Smelter	NM	Grant
350250008	66.0	64.0	63.3	-0.7	Hobbs Jefferson	NM	Lea
350290003	66.0	62.7	62.5	-0.2	Deming Airport	NM	Luna
350610008	66.3	62.2	62.0	-0.2	Los Lunas (Los Lentos)	NM	Valencia

Table 8-2 list the observed ozone DVC₂₀₁₂₋₂₀₁₆ and projected 2028 ozone DVFs for monitoring sites outside of New Mexico but within the 4-km NM modeling domain. There are small reductions in projected ozone DVFs in Arizona (0.0 and -0.1 ppb) and El Paso, Texas (0.0 to -0.2 ppb) due to the New Mexico 2028 O&G Control Strategy. However, there are more substantial reductions in projected 2028 ozone DVFs at sites in La Plata (-0.7 and -0.9 ppb) and Montezuma (-0.5 ppb) counties in southwestern Colorado that are adjacent to the New Mexico portion of the San Juan Basin where some of the 2028 O&G Control Strategy emission reductions occur.

Table 8-2. Observed ozone DVC₂₀₁₂₋₂₀₁₆ and projected 2028 ozone DVFs for the 2028 Base Case and 2028 O&G Control strategy and differences in the 2028 ozone DVFs (DVF_{Cntl} – DVF_{Base}).

AQS_ID	2012-16	Projected 2028 DVF			Site Name	State	County
	DVC (ppb)	Base (ppb)	Cntl (ppb)	Cntl - Base			
Arizona, Colorado and Texas							
40038001	68.0	64.0	63.9	-0.1	Chiricahua NM	AZ	Cochise
40170119	66.7	61.9	61.9	0.0	Petrified Forest	AZ	Navajo
80677001	67.7	66.1	65.2	-0.9	UTE 1	CO	La Plata
80677003	66.7	64.4	63.7	-0.7	UTE 3	CO	La Plata
80830006	63.0	59.7	59.2	-0.5	Cortez - Health Dept	CO	Montezuma
80830101	66.0	62.4	61.9	-0.5	Mesa Verde NP	CO	Montezuma
481410029	61.0	58.0	57.9	-0.1	Ivanhoe	TX	El Paso
481410037	71.0	66.2	66.1	-0.1	El Paso UTEP	TX	El Paso
481410044	67.7	62.5	62.4	-0.1	El Paso Chamizal	TX	El Paso
481410055	62.7	59.2	59.1	-0.1	Ascarate Park SE	TX	El Paso
481410057	66.5	63.3	63.2	-0.1	Socorro Hueco	TX	El Paso
481410058	68.0	63.4	63.4	0.0	Skyline Park	TX	El Paso
483819991	66.7	62.4	62.2	-0.2	Palo Duro	TX	Randall

8.1.2 2028 O&G Control Strategy Ozone DVF Unmonitored Area Analysis

The SMAT Unmonitored Area Analysis (UAA) was applied to estimate the spatial distribution of projected 2028 ozone DVF_{Cntrl} throughout the 4-km NM modeling domain. Figure 8-1 displays the spatial distribution of the SMAT UAA ozone DVFs for the 2028 Base Case and 2028 O&G Control Strategy where the SMAT UAA was applied without using concentration gradients in the spatial interpolation of the $DVC_{2012-2016}$. Within New Mexico, the projected 2028 DVF_{Base} tends to be mostly in the 60-71 ppb range, with a few small locations with the values dropping below 60 ppb. The highest ozone concentrations (65-71 ppb) in New Mexico for the 2028 ozone DVF_{Base} occur in the San Juan and Permian Basin as indicated by the lighter green shading (Figure 8-1, top panel). When the O&G Control Strategy is applied, the ozone DVF_{Cntrl} in the San Juan Basin is lower (i.e., in the 60-65 ppb with the light green shading completely gone) and the area of ozone DVF_{Base} in the 65-71 ppb range is greatly reduced for the ozone DVF_{Cntrl} case.

Figure 8-2 shows a spatial map of the differences in SMAT UAA projected 2028 ozone DVFs between the 2028 Base Case and 2028 O&G Control Strategy ($DVF_{Cntrl} - DVF_{Base}$) where the top and bottom panels represent ozone DVF differences without and with using the modeled concentration gradients in the SMAT UAA spatial interpolation. As shown in Chapter 7, use of concentration gradients has a large effect on the projected 2028 ozone DVFs, but it has no material effect on the differences in the ozone DVFs for the two 2028 emission scenarios as the plots appear almost identical.

Within the Permian Basin, the 2028 O&G Control Strategy reduces the ozone DVF by -0.5 to -1.5 ppb with most of the largest reductions (-1.0 to -1.5 ppb) occurring in Lea County. The 2028 O&G Control Strategy has a larger effect on the 2028 ozone DVF in the San Jun Basin with reductions of -1.0 to -3.0 ppb with the largest reductions (-2.0 to -3.0 ppb) straddling the New Mexico/Colorado state line at Rio Arriba/Archuleta Counties.

There are also isolated grid cells of SMAT UAA ozone DVF increases in the Permian and San Juan Basins due to the 2028 O&G Control Strategy. These ozone DVF increases appear to be several isolated 4-km grid cells and are likely due to highly localized ozone increases at the locations of O&G point source NO_x emission reductions due to the O&G Control Strategy. Most (e.g., 90-95%) fresh emissions of oxides of nitrogen (NO_x) are in the form of nitric oxide (NO) that is converted fairly quickly to nitrogen dioxide (NO_2). The $NO-O_3$ titration reaction ($NO + O_3 \rightarrow NO_2 + O_2$) occurs very quickly and can locally deplete ozone concentrations due to the fresh NO emissions while forming NO_2 that can form ozone further downwind during photochemistry. This can result in localized ozone increases when NO_x emissions are reduced in high NO_x emission areas, such as large urban areas or within NO_x point source plumes. The so called “ NO_x Disbenefits” effects (i.e., local ozone increases due to NO_x emission reductions) has been verified in numerous measurement and modeling studies and has been one reason that in the past Los Angeles was more likely to have higher ozone on weekend days than weekdays because of the lower morning NO_x emissions on weekend days (the “weekend effect”). Over the years as NO_x emissions have been controlled, the effects of “ NO_x Disbenefits” has been lessening but can still occur in major urban areas and in NO_x point source plumes.

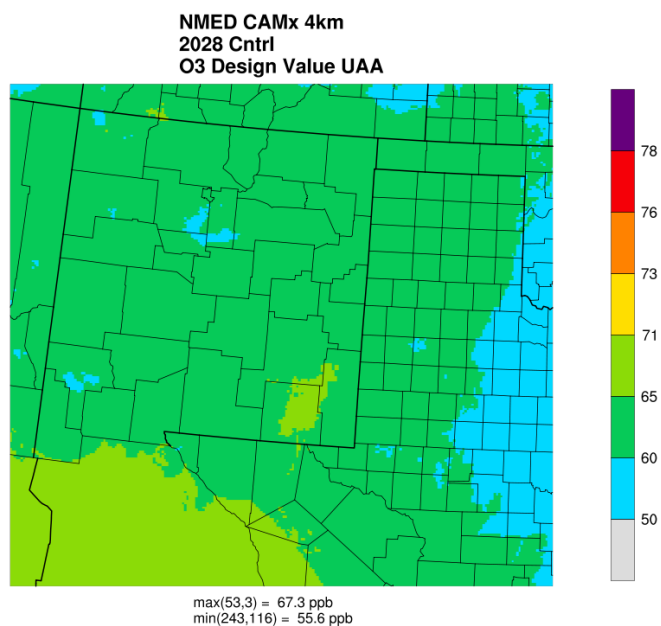
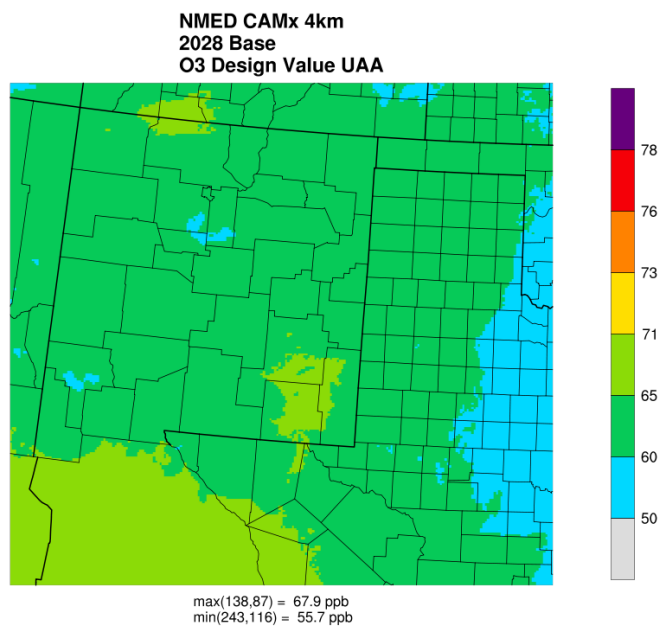


Figure 8-1. SMAT UAA spatial distribution of projected 2028 ozone DVF_{Base} (top) and DVF_{Cntrl} (bottom).

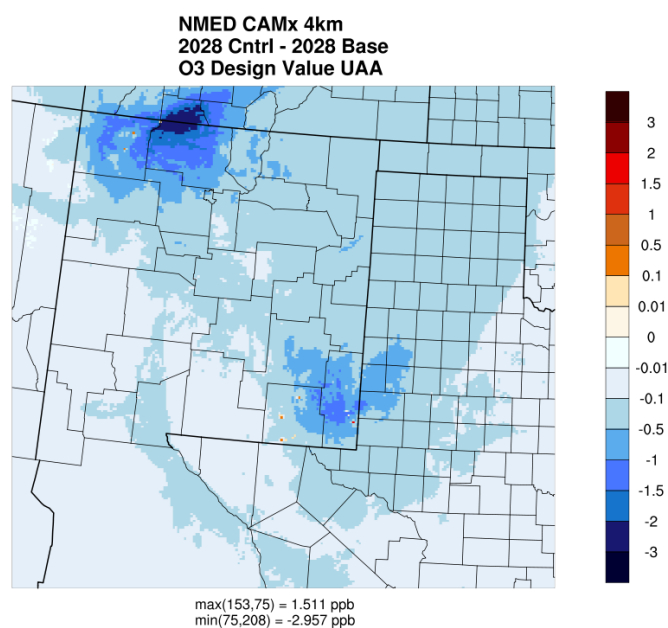
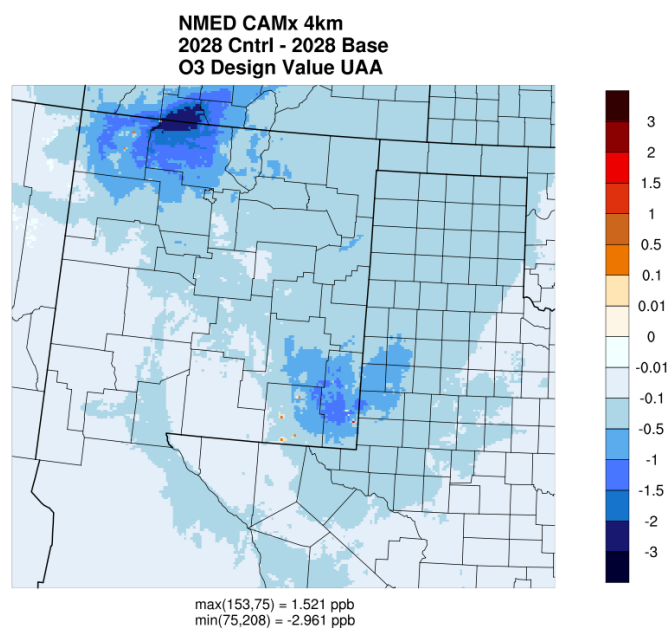


Figure 8-2. Differences in SMAT UAA projected 2028 ozone DVFs (ppb) for the 2028 Base Case and 2028 O&G Control Strategy ($DVF_{Cntrl} - DVF_{Base}$) running SMAT without (top) and with (bottom) using modeled concentration gradients in the DVC₂₀₁₂₋₂₀₁₆ spatial interpolation.

8.2 2028 Base Case and 2028 O&G Control Strategy MDA8 Ozone Concentrations

In this section we present spatial maps of modeled MDA8 ozone and the differences in MDA8 ozone for the 2028 Base Case and O&G Control Strategy emission scenarios for several example days.

8.2.1 *Daily 2014v2 and 2028 Base Case MDA8 Ozone Concentrations*

Figures 8-3 through 8-8 display example spatial maps of MDA8 ozone concentrations and their differences for the two CAMx 2028 emission scenarios for the same six days that were used to compare the 2014v2 and 2028 Base Case results that were presented in Figures 7- through 7-9. However, in the MDA8 difference plots for the two 2028 emission scenarios, a finer scale is used to better illustrate the 2028 MDA8 ozone differences due to the implementation of the O&G Control Strategy in 2028.

As discussed in Chapter 7, CAMx estimates very high MDA8 ozone concentrations on May 17, 2014 that are due to emissions from wildfires (Figure 8-3). The 2028 O&G Control Strategy scenario reduces the MDA8 ozone within the San Juan and Permian Basins by from -1 to -3 ppb on May 17th, with ozone reductions of -0.1 to -0.5 ppb spanning the area between the two Basins. There are areas of MDA8 ozone increases around the western edges of the O&G control area in the San Juan Basin with ozone increases as high as +1.4 ppb.

On June 5, 2014, the 2028 Base Case has CAMx-estimated MDA8 ozone concentrations in excess of the 70 ppb 2015 ozone NAAQS in northeast San Juan and northwest Rio Arriba Counties with a peak MDA8 ozone of 74 ppb on the border with and just inside of Colorado (Figure 8-4). The 2028 O&G Control Strategy is very effectively reducing these high MDA8 ozone exceedances in the San Juan Basin with ozone reductions of up to -4.6 ppb that reduce the MDA8 ozone to below the 2015 ozone NAAQS in San Juan and Rio Arriba Counties. MDA8 ozone is also reduced in the Permian Basin, although not nearly as great as in the San Juan Basin on this day. There are very small areas of ozone increases due to the 2028 O&G Control Strategy within New Mexico that are less than 0.1 ppb, although they are as high as 0.4 ppb near the Four Corners location.

The 2028 Base Case MDA8 ozone on July 12, 2014 in New Mexico is mostly below 60 ppb (blue) with some isolated areas slightly above that (green; Figure 8-5). The 2028 O&G Control Strategy results in MDA8 ozone reductions of more than -0.5 ppb over large areas expanding out of the two O&G Basins with reductions as high as -4.6 ppb in the San Juan Basin and as high as -1.0 to -1.5 ppb reduction in the Permian Basin. In the Permian Basin in the southeast corner of New Mexico, there are ozone increases due to the 2028 O&G Control Strategy that appear to be mostly in the +0.1 to +0.5 ppb range, with a peak increase of +1.6 ppb.

Elevated MDA8 ozone concentrations approaching, but below, the 2015 ozone NAAQS are estimated to occur in San Juan County on July 24, 2014 with a peak value of 71.3 ppb that is above the NAAQS occurring right across the border in Colorado (Figure 8-6). Although the 2028 O&G Control Strategy reduces the MDA8 ozone on this day across wide areas of New Mexico, with ozone reductions as high as -2.8 ppb in the Permian Basin, there are estimated increases in MDA8 ozone in San Juan County. These MDA8 ozone increases in San Juan County due to the 2028 O&G Control Strategy and are as high as +6.4 ppb. These increased in MDA8 ozone concentrations in San Juan County

due to the 2028 O&G Control Strategy are sufficient to increase the MDA8 ozone concentration in one grid cell to 71.0 ppb, which exceeds the 2015 ozone NAAQS.

On July 26th there are patches of elevated MDA8 ozone in the 2028 Base Case in the 65-71 ppb range in northern New Mexico with a peak MDA8 ozone concentration of 72.3 ppb in the northeast corner of Cibola County that exceeds the ozone NAAQS (Figure 8-7). The 2028 O&G Control Strategy reduces the MDA8 ozone Peak in Cibola County by -0.4 ppb to 71.9 ppb, which still exceeds the NAAQS. The 2028 O&G Control Strategy results in reductions in MDA8 ozone concentrations in excess of -3.0 ppb in the San Juan and Permian Basins with a maximum reduction of -5.4 ppb. The ozone reductions in the San Juan Basin are sufficient to reduce MDA8 ozone concentrations that were in the 65-71 ppb range in the 2028 Base Case to below 65 ppb.

On August 14, 2014, there are small areas of MDA8 ozone concentrations in the 65-71 ppb range in New Mexico on the northern border with Colorado and in southern border in Doña Ana County with the domain-wide peak ozone of 71.2 ppb just over the border from Doña Ana County in El Paso (Figure 8-8). The 2028 O&G Control Strategy has little effects on the MDA8 ozone peak in El Paso that remains at 71.2 ppb. The 2028 O&G Control Strategy reduces MDA8 ozone in the San Juan and Permian Basins by as much as -1.8 ppb; the ozone reductions in San Juan County reduce the size of the elevated ozone in the 65-71 ppb range. There are also areas of ozone increases to the west and northeast of the San Juan Basin due to the 2028 O&G Control Strategy that are as much as +1.6 ppb.

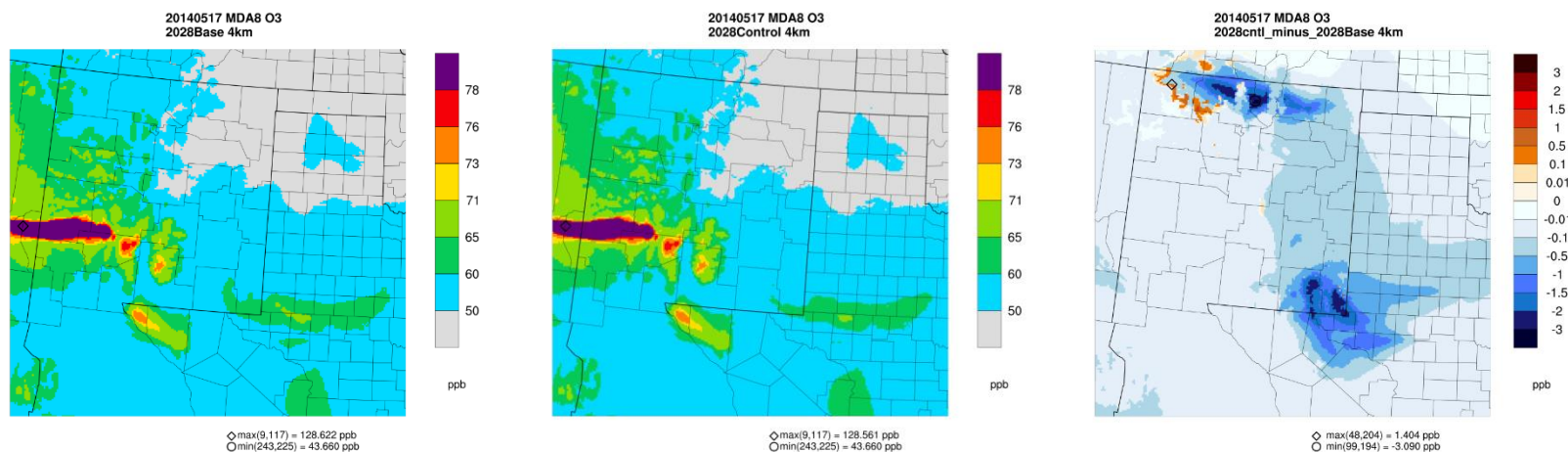


Figure 8-3. CAMx estimated MDA8 ozone concentrations (ppb) on May 17, 2014 for the 2028 Base Case (left), 2028 O&G Control Strategy Case (middle) and their difference (right).

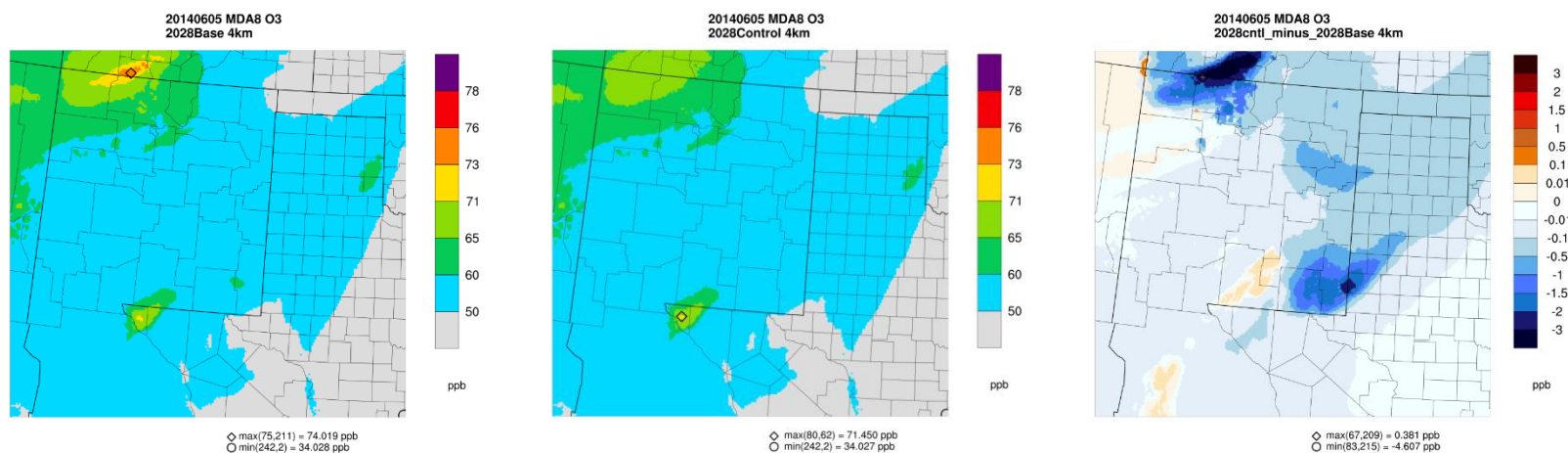


Figure 8-4. CAMx estimated MDA8 ozone concentrations (ppb) on June 5, 2014 for the 2028 Base Case (left), 2028 O&G Control Strategy (middle) and their difference (right).

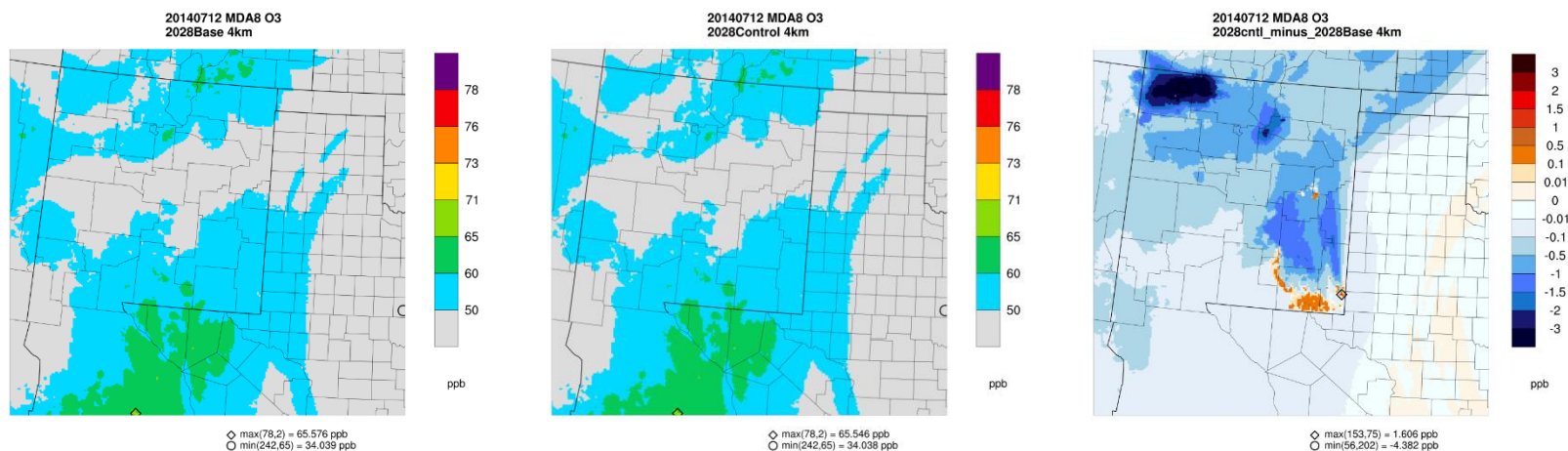


Figure 8-5. CAMx estimated MDA8 ozone concentrations (ppb) on July 12, 2014 for the 2028 Base Case (left), 2028 O&G Control Strategy (middle) and their difference (right).

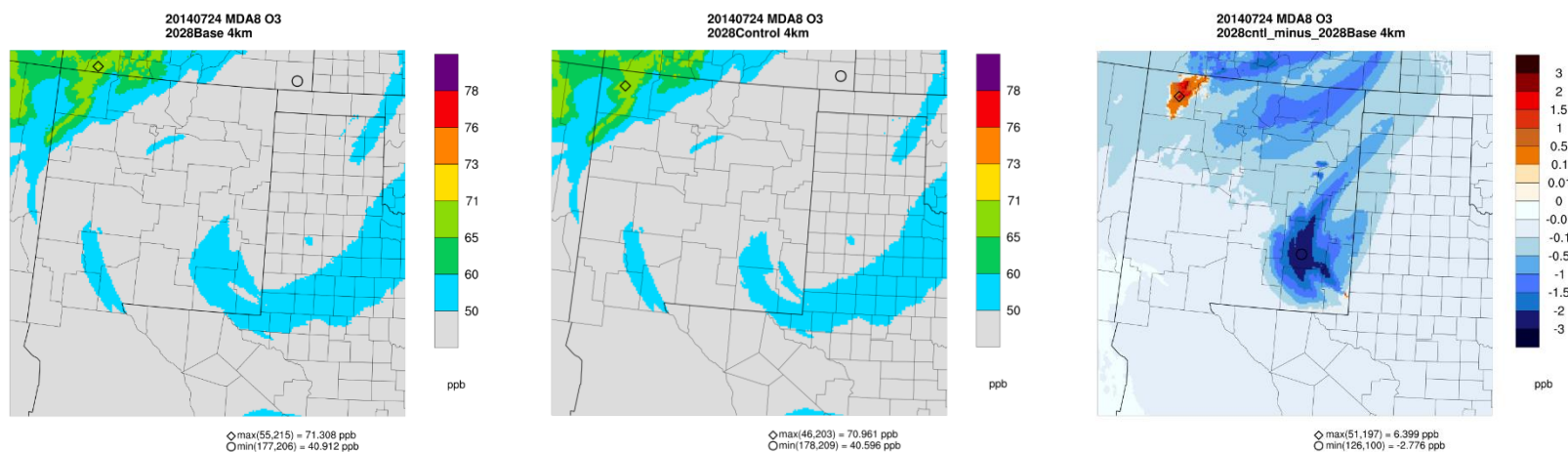


Figure 8-6. CAMx estimated MDA8 ozone concentrations (ppb) on July 24, 2014 for the 2028 Base Case (left), 2028 O&G Control Strategy (middle) and their difference (right).

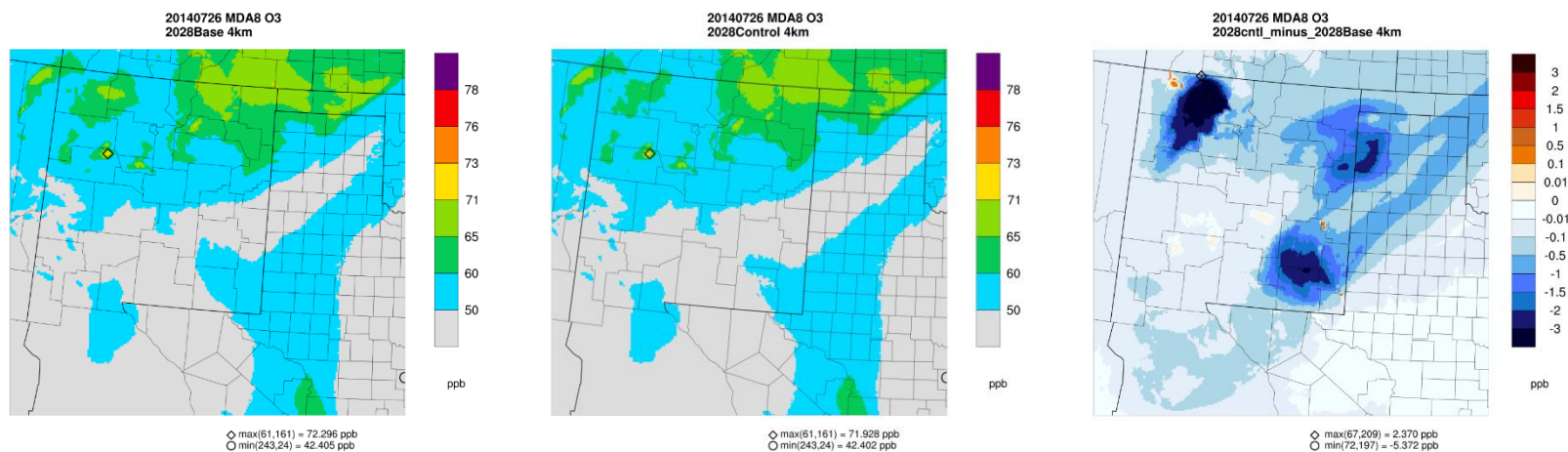


Figure 8-7. CAMx estimated MDA8 ozone concentrations (ppb) on July 26, 2014 for the 2014v2 Base Case (left), 2028 Base Case (middle) and their difference (right).

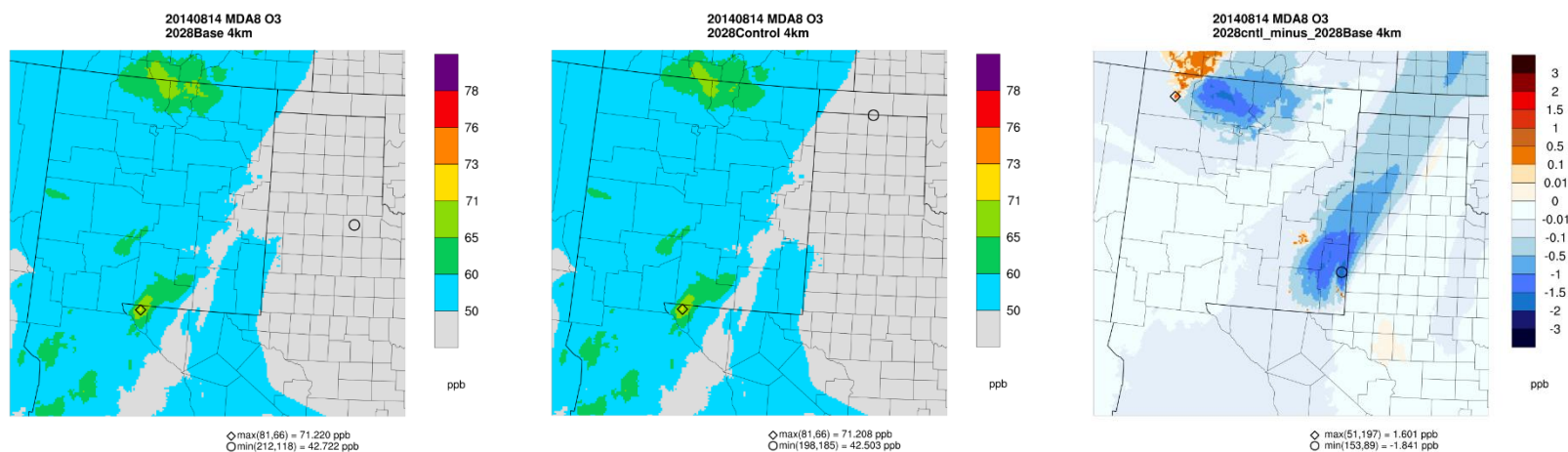


Figure 8-8. CAMx estimated MDA8 ozone concentrations (ppb) on August 14, 2014 for the 2014v2 Base Case (left), 2028 Base Case (middle) and their difference (right).

8.3 Conclusions of the 2028 Base and 2028 O&G Control Strategy Modeling

The O&G Control Strategy results in wide areas of reductions in 2028 Base Case MDA8 ozone concentrations and SMAT UAA projected 2028 ozone DVFs across large portions of New Mexico, with the largest ozone reductions occurring in the San Juan and Permian Basins. There are also areas of increases in MDA8 ozone and SMAT UAA projected 2028 ozone DVFs due to the O&G Control Strategy that usually occur in isolated locations within and near the San Juan and Permian Basin. The ozone increases in the SMAT UAA projected DVFs across New Mexico due to the O&G Control Strategy occur in a few isolated grid cells in the San Juan and Permian Basins; the projected 2028 ozone DVFs at all the monitoring sites saw only ozone reductions with no ozone increases due to the O&G Control Strategy. The size of the areas and magnitudes of the ozone reductions due to the 2028 O&G Control Strategy scenario were much greater than the ozone increases.

Using the current year ozone design value from 2012-2016 ($DVC_{2012-2016}$), the projected 2028 ozone DVFs for both the 2028 Base Case and 2028 O&G Control Strategy are below the 70 ppb 2015 ozone NAAQS with the highest values for the 2028 Base and O&G Control Cases occurring at the Desert View (67.0 and 66.8 ppb) monitoring site in Doña Ana County and the Carlsbad (66.7 and 66.4 ppb) monitoring site in Eddy County. However, as noted in Chapter 1 (Table 1-1), more recent observed DVs at Desert View and Carlsbad are much higher than the observed current year $DVC_{2012-2016}$ used in the 2028 ozone DVF projections presented in Chapters 7 and 8. The sensitivity of the choice of current year DVC on the projected 2028 ozone DVFs is analyzed in Chapter 9.

9. SENSITIVITY OF PROJECTED 2028 OZONE DESIGN VALUES TO CURRENT YEAR OZONE DESIGN VALUES

Following EPA photochemical grid modeling guidance ozone projection procedures, the projected 2028 future year ozone design values (DVs) were below the 70 ppb 2015 ozone NAAQS at all monitoring sites in New Mexico. EPA's guidance uses as a starting point for the future year ozone projections an average of three current year design values centered on the base modeling year (i.e., $DVC_{2012-2016}$). However, at many sites in New Mexico, the current year $DVC_{2012-2016}$ is lower than the most recent 2017-2019 ozone design values ($DV_{2017-2019}$). For example, at the Desert View site in Doña Ana County the most recent $DV_{2017-2019}$ is 77 ppb that is 5 ppb higher than the $DVC_{2012-2016}$ (72.0 ppb). And the most recent $DV_{2017-2019}$ at the Carlsbad site in Eddy County (79 ppb) is 7.7 ppb higher than the $DVC_{2012-2016}$ (71.3 ppb) used in the 2028 ozone DVF projections presented in Chapters 7 and 8.

In this Chapter we examine the sensitivity of the 2028 ozone DVF projections to the observed current year ozone design value (DVC) used as the starting point for the 2028 ozone DVF projections. Instead of using the $DVC_{2012-2016}$ as the starting point for the 2028 ozone DVF projections, we use the average of three ozone design values from 2015-2019 5-year period (i.e., $DVC_{2015-2019}$) and also conduct 2028 ozone DVF projections using the latest ozone $DV_{2017-2019}$ as the DVC. Note that we are still using the CAMx 2014v2 Base Case modeling results for the denominator of the RRFs used to make the 2028 ozone DVF projections that will not account for the changes in emissions between 2014 and the more current years that affect the magnitude of the ozone $DVC_{2015-2019}$ and $DV_{2017-2019}$. This includes emission reductions from mobile sources as well as emission increases from O&G sources. Thus, the 2028 ozone DVF projection sensitivity analysis to base year ozone DVC has uncertainties and will likely overstate 2028 ozone DVFs in and near the Permian Basin where the more current year O&G emissions are higher than they were in 2014 and understate the DVFs in areas not affected by O&G emissions from the Permian Basin.

9.1 2028 Ozone Design Value Sensitivity Analysis using $DVC_{2015-2019}$

Table 9-1 presents the current year ozone design value from 2015-2019 ($DVC_{2015-2019}$) and the projected 2028 ozone DVFs using the $DVC_{2015-2019}$ as the ozone projection DVC starting point. The $DVC_{2015-2019}$ are higher than the EPA-recommended (EPA, 2018) $DVC_{2012-2016}$ used as the ozone DVF projection starting point in Chapters 7 and 8. For example, there are four monitoring sites with $DVC_{2015-2019}$ above the NAAQS with Desert View (74.3 ppb), Santa Teresa (74.0 ppb), and Carlsbad (73.7 ppb) having $DVC_{2015-2019}$ of, respectively, 2.3, 2.7 and 4.7 ppb higher than the corresponding $DVC_{2012-2016}$. Note that the $DVC_{2015-2019}$ at Carlsbad Caverns NP (71.0 ppb) also exceeds the NAAQS, however it was not in operation for the $DVC_{2012-2016}$ period and the $DVC_{2015-2019}$ is based on just 3-years of data (2016-2018), so is actually based on just one design value, $DV_{2016-2018}$.

The 2028 projected ozone DVFs for the 2028 Base Case using the current year DVC₂₀₁₅₋₂₀₁₉ has one monitoring site that exceeds the 2015 ozone NAAQS, 71.2 ppb at Carlsbad. The next highest 2028 ozone DVFs for the 2028 Base Case are 69.3 ppb at Carlsbad Caverns NP and 69.1 ppb at Desert View.

The emissions controls in the 2028 O&G Control Strategy are sufficient to reduce the 2028 Base Case ozone DVF at Carlsbad (71.2 ppb) to below the ozone NAAQS (70.9 ppb) when DVC₂₀₁₅₋₂₀₁₉ current year design value is used in the 2028 ozone DVF projections.

Table 9-1. Projected 2028 ozone DVFs for the 2015-2019 current year design value DVC₂₀₁₅₋₂₀₁₉ sensitivity analysis.

AQS_ID	2015-19	Projected 2028 DVF			Site Name	County
	DVC (ppb)	Base (ppb)	Cntl (ppb)	Cntl - Base		
350010023	69.0	63.4	63.1	-0.3	Del Norte HS	Bernalillo
350010029	66.0	61.0	60.5	-0.5	South Valley	Bernalillo
350011012	69.0	62.7	62.4	-0.3	Foothills	Bernalillo
350130008	68.7	62.1	62.0	-0.1	La Union	Doña Ana
350130020	70.7	65.7	65.7	0.0	Chaparral	Doña Ana
350130021	74.3	69.1	68.9	-0.2	Desert View	Doña Ana
350130022	74.0	68.6	68.5	-0.1	Santa Teresa	Doña Ana
350130023	67.7	62.9	62.7	-0.2	Solano	Doña Ana
350151005	73.7	71.2	70.9	-0.3	Carlsbad	Eddy
350153001	71.0	69.3	69.3	0.0	Carlsbad Caverns NP	Eddy
350250008	69.3	67.2	66.5	-0.7	Hobbs Jefferson	Lea
350390026	66.3	63.0	62.2	-0.8	Coyote Ranger Dist	Rio Arriba
350431001	67.0	61.2	60.9	-0.3	Bernalillo (E Avenida)	Sandoval
350450009	67.0	63.6	62.8	-0.8	Bloomfield	San Juan
350450018	69.0	66.7	65.2	-1.5	Navajo Lake	San Juan
350451005	67.3	64.2	62.9	-1.3	Substation	San Juan
350490021	65.0	61.2	61.0	-0.2	Santa Fe Airport	Santa Fe
350610008	66.7	62.6	62.3	-0.3	Los Lunas (Los Lentes)	Valencia

9.2 2028 Ozone Design Value Sensitivity Analysis using DVC₂₀₁₇₋₂₀₁₉

Table 9-2 shows the results of the 2028 ozone DVF projection current year ozone design value sensitivity analysis using the latest 2017-2019 ozone design value as the starting point for the 2028 ozone projections. There are three monitors in New Mexico with DV₂₀₁₅₋₂₀₁₉ above the NAAQS: Desert View (77.0 ppb), Santa Teresa (76.0 ppb) and Carlsbad (79 ppb). These DV₂₀₁₇₋₂₀₁₉ values are, respectively, 5.0, 4.7 and 10.0 ppb higher than the DVC₂₀₁₂₋₂₀₁₆ used as the

ozone projection starting point in the 2028 ozone DVF projections presented in Chapters 7 and 8.

For the 2028 Base Case, there are two sites with projected 2028 ozone DVFs in the DV₂₀₁₇₋₂₀₁₉ current year design value sensitivity test that have DVF values above the 2015 ozone NAAQS: 71.6 ppb at Desert View and 76.4 ppb at Carlsbad. The 76.0 ppb DV₂₀₁₇₋₂₀₁₉ at Santa Teresa is reduced to 70.5 ppb under the 2028 Base Case so attains the ozone NAAQS.

The projected 2028 ozone DVF using the DV₂₀₁₇₋₂₀₁₉ as the current year DVC under the O&G Control Strategy are 71.4 ppb at Desert View and 76.0 at Carlsbad so still exceed the 2015 ozone NAAQS. In fact, the Carlsbad 76.0 ppb ozone DVF even exceeds the 2008 ozone NAAQS.

Table 9-2. Projected 2028 ozone DVFs for the 2017-2019 current year design value DV₂₀₁₇₋₂₀₁₉ sensitivity analysis.

AQS_ID	2017-19	Projected 2028 DVF			Site Name	County
	DVC (ppb)	Base (ppb)	Cntl (ppb)	Cntl - Base		
350010023	70.0	64.3	64.0	-0.3	Del Norte HS	Bernalillo
350010029	67.0	61.9	61.4	-0.5	South Valley	Bernalillo
350011012	71.0	64.5	64.2	-0.3	Foothills	Bernalillo
350130008	70.0	63.3	63.2	-0.1	La Union	Doña Ana
350130020	73.0	67.8	67.8	0.0	Chaparral	Doña Ana
350130021	77.0	71.6	71.4	-0.2	Desert View	Doña Ana
350130022	76.0	70.5	70.3	-0.2	Santa Teresa	Doña Ana
350130023	70.0	65.0	64.8	-0.2	Solano	Doña Ana
350151005	79.0	76.4	76.0	-0.4	Carlsbad	Eddy
350250008	71.0	68.9	68.1	-0.8	Hobbs Jefferson	Lea
350390026	67.0	63.6	62.8	-0.8	Coyote Ranger Dist	Rio Arriba
350431001	68.0	62.1	61.8	-0.3	Bernalillo (E Avenida)	Sandoval
350450009	68.0	64.6	63.7	-0.9	Bloomfield	San Juan
350450018	69.0	66.7	65.2	-1.5	Navajo Lake	San Juan
350451005	69.0	65.8	64.5	-1.3	Substation	San Juan
350490021	66.0	62.2	62.0	-0.2	Santa Fe Airport	Santa Fe
350610008	68.0	63.8	63.5	-0.3	Los Lunas (Los Lentes)	Valencia

10. 2028 SOURCE SECTOR APCA OZONE SOURCE APPORTIONMENT MODELING

Ozone source apportionment modeling was conducted to determine the contributions of Source Sectors within New Mexico to 2028 ozone concentrations and projected future year ozone design values (DVF) under the 2028 New Mexico oil and gas (O&G) control strategy emissions scenario. The Anthropogenic Precursor Culpability Assessment (APCA) version of the CAMx ozone source apportionment tool was used and the modeling also obtained contributions from Colorado, Texas and the remainder of U.S. states as well as international anthropogenic emissions.

10.1 Versions of Ozone Source Apportionment

CAMx includes two ozone source apportionment tools: the Ozone Source Apportionment Technology (OSAT) and the Anthropogenic Precursor Culpability Assessment (APCA). Both use tagged tracer species that track ozone formation from VOC (V_i) and NO_x ($\text{NIT}_i + \text{RGN}_i$) emissions from each user-specified Source Group (i). A Source Group can consist of a Source Region and/or Source Category. A typical OSAT/APCA application will use a Source Region map that divides the modeling domain into geographic regions and separate emission files of different Source Categories are provided as input to CAMx; ozone source apportionment is obtained for Source Groups that are defined as the intersection of the Source Regions with the Source Categories (e.g., on-road mobile sources from New Mexico). The ozone source apportionment tool runs in parallel to the CAMx host model and extracts information on ozone formation and assigns it to the user-defined Source Groups.

There are 10 reactive tracers used to track ozone formation for each user-defined Source Group as follows:

V_i	VOC emissions
NIT_i	Nitric oxide (NO) and nitrous acid (HONO) emissions
RGN_i	Nitrogen dioxide (NO_2), nitrate radical (NO_3) and dinitrogen pentoxide (N_2O_5)
TPN_i	Peroxy acetyl nitrate (PAN), analogues of PAN and peroxy nitric acid (PNA)
NTR_i	Organic nitrates (RNO_3)
HN3_i	Gaseous nitric acid (HNO_3)
O3N_i	Ozone formed under NO_x sensitive conditions
O3V_i	Ozone formed under VOC sensitive conditions
OON_i	Odd-oxygen in NO_2 formed from O3N_i
OOV_i	Odd-oxygen in NO_2 formed from O3V_i

For each time step and grid cell, when ozone is formed in the host model OSAT determines whether the ozone formation was more VOC sensitive or NO_x sensitive and apportions the ozone formed to Source Groups based on the relative contribution of the limiting precursor to the total precursor (e.g., under VOC sensitive conditions $V_i / \sum V_i$). APCA differs from OSAT in that it will only allocate ozone formed to natural (e.g., biogenic) emissions Source Groups when the ozone formed is due to natural VOC interacting with natural NO_x. So when ozone is formed due to biogenic VOC emissions interacting with anthropogenic NO_x emissions under VOC sensitive ozone formation conditions, a case OSAT would assign to the natural Source Group O3V_i tracer, APCA redirects the ozone formed to the anthropogenic Source Group O3N_i tracer. APCA was designed to provide more control strategy relevant information than OSAT and is used in identifying ozone contributions in emissions culpability assessments (e.g., CSAPR³⁸). However, OSAT has to be used to obtain information on whether ozone formation is more VOC or NO_x sensitive. Details on the CAMx OSAT and APCA source apportionment tools are provided in Chapter 7 of the CAMx user's guide.³⁹ Since we are running CAMx v7.1, it uses the third version of OSAT3 and corresponding version of APCA.

As the main focus of the 2028 Source Sector ozone source apportionment modeling is to identify the contributions of anthropogenic emission source sectors and regions to elevated MDA8 ozone concentrations in New Mexico, the APCA version of ozone source apportionment tool was used.

10.2 2028 Source Sector APCA Ozone Source Apportionment Specifications

Details on the design and specifications of the 2028 Source Sector APCA ozone source apportionment simulate are provide below.

10.2.1 2028 O&G Control Strategy Emissions Scenario

The 2028 Source Sector APCA ozone source apportionment was conducted using the 2028 New Mexico O&G Control Strategy emissions scenario.

10.2.2 Definition of Source Groups

The 2028 Source Sector APCA ozone source apportionment simulation used a Source Region map to define geographic regions of emission areas to be tracked. Separate source contributions were also obtained for 9 emission Source Categories as well as contributions due to Boundary Conditions (BCs) around the lateral edges of the 36-km grid resolution domain.

10.2.2.1 Boundary Conditions

The CAMx v7 source apportionment tool has a new capability to provide separate contributions due to stratified BCs. Typically, these stratifications will be different source sectors from outside of the CAMx modeling domain. WRAP conducted 2014 GEOS-Chem modeling for a base case (BASE), a 2014 GEOS-Chem no

³⁸ <https://www.epa.gov/csapr>

³⁹ http://www.camx.com/files/camxusersguide_v7-10.pdf

international anthropogenic emissions case (i.e., Zero-out Rest of World or ZROW) and a no global anthropogenic emissions case (i.e., just natural emissions). Output from the three 2014 GEOS-Chem runs were processed to generate lateral BCs for the CAMx 36-km 36US1 North America modeling domain that contained: (1) the contributions of international anthropogenic emissions (BC_{Intl}); (2) the contributions of U.S. anthropogenic emissions (BC_{US}); and (3) the contributions of natural sources ($BC_{Natural}$). Details on the WRAP 2014 GEOS-Chem base, ZROW and Natural modeling are contained in a Run Specification Sheet⁴⁰ and the WRAP/WAQS 2014v2 model performance evaluation webpage.⁴¹

This results in the 2028 Source Sector APCA ozone source apportionment simulation tracking ozone contributions from three Source Groups for the lateral boundaries ($BC_{Natural}$, BC_{Intl} and BC_{US}). Contributions due to the top BC concentration as well as Initial Concentrations (IC) were also separately tracked resulting in 5 Source Groups used to track the contributions of BC and IC.

10.2.2.2 Source Regions

Five source regions were used in the 2028 Source Sector APCA ozone source apportionment simulation as shown in Figure 10-1:

1. New Mexico;
2. Texas;
3. Colorado;
4. Remainder U.S. states plus coastal water out to 200 nautical miles (nmi) from the U.S. coast; and
5. International, which included Mexico, Canada and waters off their coasts plus waters more than 200 nmi off the U.S. coast.

⁴⁰ https://views.cira.colostate.edu/docs/iwdw/platformdocs/WRAP_2014/Run_Spec_WRAP_2014_Task1-7_NAT-ZROW_v4.pdf

⁴¹ https://views.cira.colostate.edu/iwdw/docs/WRAP_WAQS_2014v2_MPE.aspx

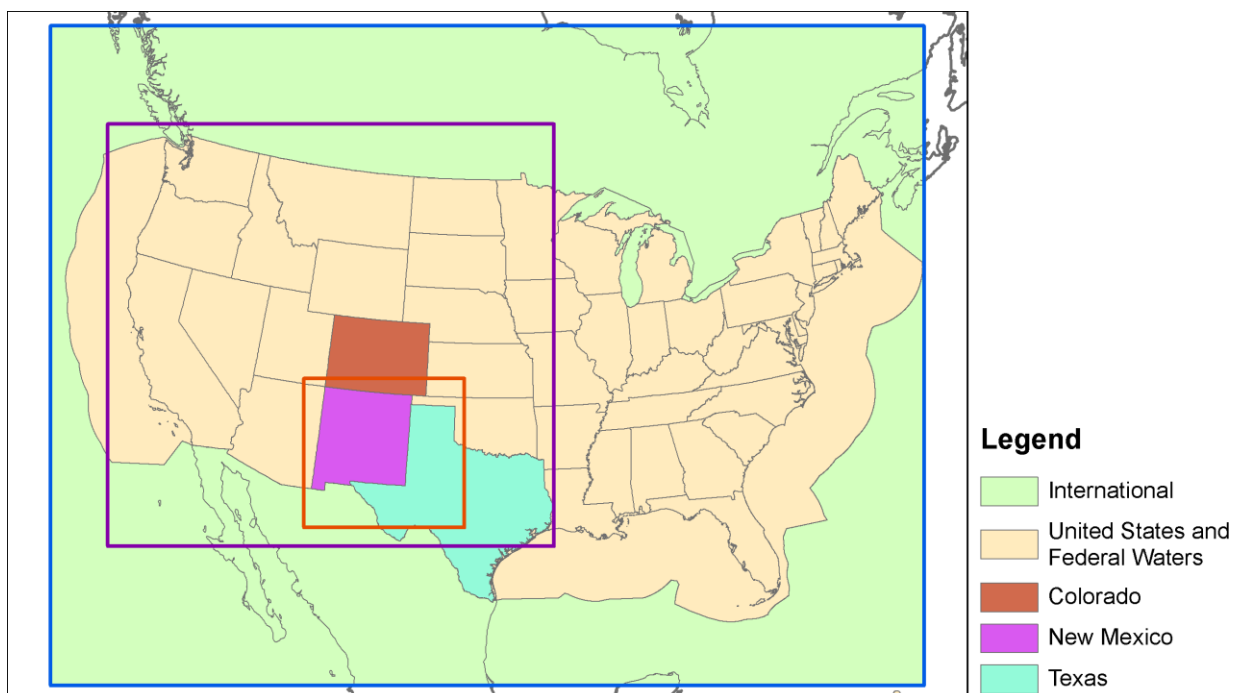


Figure 10-1. Source regions used in the 2028 Source Sector APCA ozone source apportionment simulation.

10.2.2.3 Source Categories

The emissions inventory was divided up into 9 Source Categories in the 2028 Source Sector APCA ozone source apportionment modeling as follows:

1. Natural (biogenic, lightning NO_x, windblown dust and oceanic [sea salt and dimethyl sulfide]);
2. Fires (U.S. wildfires, wildland prescribed burns and agricultural burning and other [Mexico/Canada] fires);
3. Oil and gas point sources (surrogate for midstream O&G);
4. Oil and gas non-point sources (surrogate for upstream O&G);
5. EGU point;
6. Non-EGU point;
7. On-road mobile;
8. Non-road mobile; and
9. Remainder anthropogenic.

Since the APCA version of the CAMx ozone source apportionment tool is being utilized, Natural emissions has to be the first Source Category so APCA knows which Source Category is uncontrollable.

10.2.2.4 Source Groups

With 5 Source Regions and 9 Source Categories, plus 5 Source Groups for IC/BC, there is a total of 50 Source Groups that separate ozone source contributions are obtained ($50 = 5 \times 9 + 5$).

10.3 2028 Source Sector APCA Ozone Source Apportionment Modeling Results

The 2028 Source Sector APCA ozone source apportionment modeling results were analyzed to obtain the contributions of the different Source Sectors within New Mexico to projected future year 2028 ozone design values (DVs) as well as contributions to Maximum Daily Average 8-hour (MDA8) ozone concentrations. The 2028 ozone DVF and modeled MDA8 ozone concentrations were analyzed at the monitoring sites as well as across the 4-km New Mexico domain. Figure 10-2 shows the locations of the monitoring sites within the 4-km New Mexico domain.

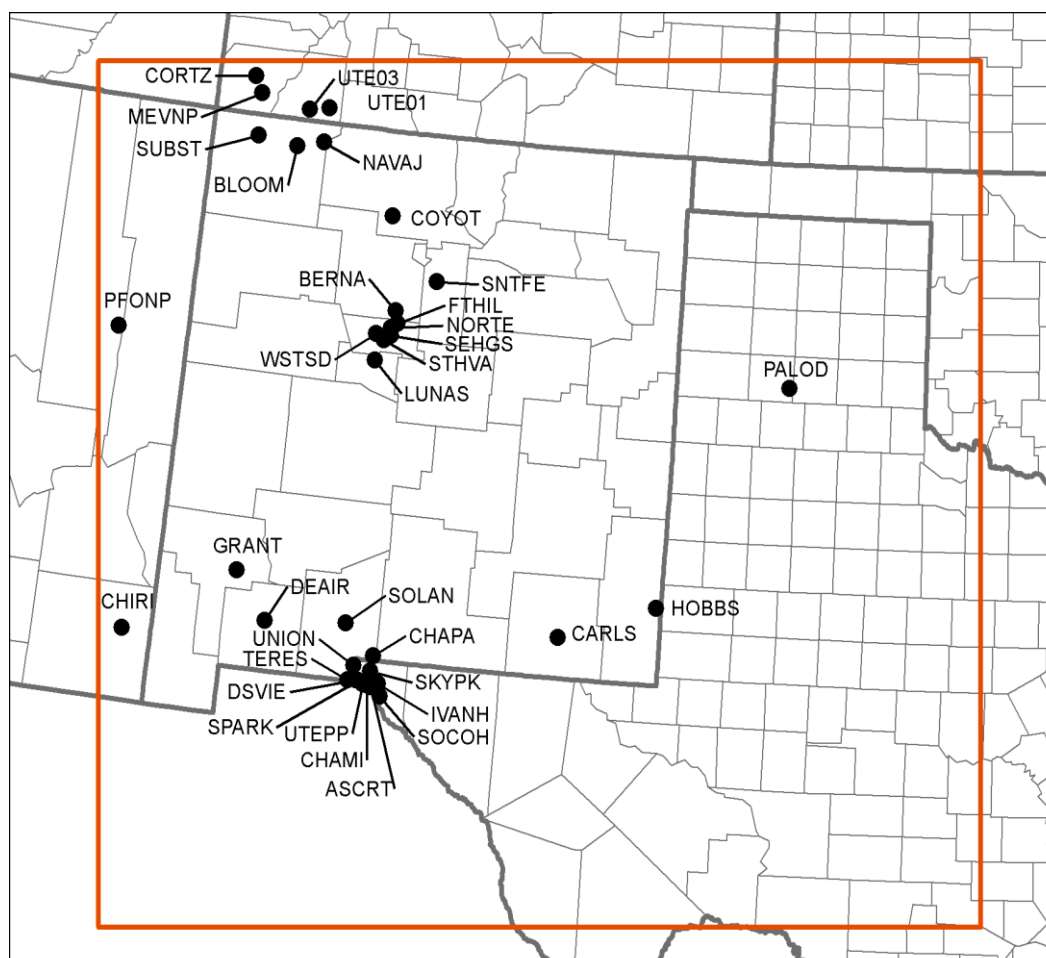


Figure 10-2. Locations of ozone monitoring sites within the 4-km New Mexico modeling domain.

10.3.1 Source Sector Contributions to Projected 2028 Ozone DVFs

In this section, the contributions of Source Sector emissions within New Mexico and the entire United States to future year projected 2028 ozone design values (DVF) at New Mexico monitoring sites and across the 4-km New Mexico domain are analyzed.

10.3.1.1 New Mexico Source Sector 2028 Ozone DVF Contributions

Table 10-1 displays the current year 2012-2016 DVC, the projected 2028 ozone DVF for the 2028 O&G Control Scenario and the reductions in the 2028 ozone DVF due to the removal of anthropogenic emissions in New Mexico for each of the 7 anthropogenic emissions Source Sectors at all monitoring sites in New Mexico. The incremental ozone contributions in the 2028 ozone DVF due to New Mexico emissions from the 7 Source Sectors are shown for several New Mexico monitoring sites in Figures 10-3 through 10-18.

At the three monitoring sites in San Juan County, New Mexico emissions from EGU and O&G Source Sectors contribute the most to the 2028 ozone DVF (Table 10-1). The largest ozone contribution is 3.1 ppb for the New Mexico EGU Source Sector at the SUBST site (Figure 10-5) due to its close proximity to the Four Corners Power Plant (FCPP) that is assumed to have Units 4 and 5 operating in 2028. The EGU ozone contributions fall off with distance from the FCPP as seen at the BLOOM (1.9 ppb; Figure 10-4), NAVAJ (1.7 ppb; Figure 10-3) and COYOT (0.5 ppb; Figure 10-6) monitoring sites. New Mexico O&G Point contributes 0.2 to 0.9 ppb and O&G Non-Point contributes 0.5 to 2.1 ppb to 2028 ozone DVFs at the four northern New Mexico monitoring sites in San Juan and Rio Arriba Counties. All other Source Sectors have contributions of 0.5 ppb or less at the northern New Mexico sites.

Sites in Central New Mexico include those in Bernalillo County (Figures 10-7 through 10-10) as well as two sites in neighboring counties (Figures 10-11 and 10-12). Ozone concentrations in Bernalillo County are highly influenced by emissions from Albuquerque, which is by far the largest city in New Mexico. So, Source Sectors associated with population centers (e.g., on-road, non-road and other anthropogenic) tend to have the highest contributions to the 2028 ozone DVFs at these sites. Although they have different magnitudes of ozone contributions, the rankings of the Source Sector contributions are very similar at the Bernalillo County sites with Other Anthropogenic being highest followed by On-Road and Non-Road mobile with the other four Source Sectors being half or less of the top three Source Sectors. On-Road mobile is the highest followed by Other Anthropogenic and Non-Road at the Santa Fe (Figure 10-11) and Sandoval County (Figure 10-12) sites, with all other Source Sector contributions being much lower.

Sites in the southern New Mexico (Figures 10-13 through 10-18) include those in southern Doña Ana County on the border with Texas that tend to have mostly small contributions from New Mexico Source Sectors with the exception of EGU (0.7 to 0.9 ppb), due to the close proximity of the Rio Grande Power Plant to some of the sites, and On-Road mobile (0.4-0.5 ppb) due to population centers along I-25 (e.g., Sunland Park, Santa Teresa, etc.). The Solano monitor (Figure 10-16) has higher ozone contributions due to On-Road (1.2 ppb) and Non-Road (0.7 ppb) mobile sources because of the higher mobile emissions from the City of Las Cruces, which is the second largest city in New Mexico.

New Mexico emissions from the O&G Point and Non-Point Sources sectors have the highest ozone contribution at the Carlsbad (0.5 and 0.5 ppb) and Hobbs (0.9 and 1.1 ppb) monitoring sites in southeastern New Mexico (Figures 10-17 and 10-18). These two southeastern New Mexico monitors are essentially within the Permian Basin. The contribution of On-Road to the 2028 ozone DVF at Carlsbad and Hobbs sites is 0.3 ppb, with all other Source Sector contributions being lower.

Table 10-1. Reduction in 2028 ozone DVF due to the elimination of emissions from 7 Source Sectors in New Mexico.

AQS_ID	Site_ID	DVC	DVF	O&GPT	O&GNP	EGU	NonEGU	OnRoad	NonRoad	OAnth
Northern New Mexico										
350390026	COYOT	64.0	60.0	-0.2	-0.5	-0.5	0.0	-0.2	-0.1	0.0
350450009	BLOOM	64.3	60.2	-0.7	-1.4	-1.9	0.0	-0.4	-0.1	-0.1
350450018	NAVAJ	67.0	63.3	-0.9	-2.1	-1.7	-0.1	-0.4	-0.2	-0.1
350451005	SUBST	63.7	59.6	-0.6	-1.5	-3.1	-0.1	-0.5	-0.2	-0.2
Central New Mexico										
350010023	NORTE	66.3	60.7	-0.2	-0.3	-0.5	-1.0	-2.7	-2.0	-3.6
350010024	SEHGS	68.0	62.0	-0.2	-0.3	-0.5	-1.1	-2.5	-1.9	-3.2
350010029	STHVA	66.0	60.5	-0.3	-0.5	-0.5	-1.0	-2.2	-1.7	-2.4
350010032	WSTSD	67.0	62.1	-0.2	-0.4	-0.4	-0.4	-1.6	-1.2	-1.8
350011012	FTHIL	65.0	58.8	-0.2	-0.3	-0.5	-0.7	-2.5	-2.0	-3.0
350431001	BERNA	64.0	58.1	-0.1	-0.2	-0.4	-0.4	-2.1	-1.5	-1.9
350490021	SNTFE	64.3	60.4	-0.2	-0.3	-0.2	-0.3	-1.2	-0.7	-0.8
Southern New Mexico										
350130008	UNION	66.3	59.8	-0.2	-0.2	-0.7	0.0	-0.5	-0.3	-0.1
350130017	SPARK	67.0	61.8	-0.2	-0.2	-0.9	0.0	-0.4	-0.2	-0.2
350130020	CHAPA	67.0	62.2	-0.1	-0.1	-0.3	0.0	-0.2	-0.1	-0.1
350130021	DSVIE	72.0	66.8	-0.2	-0.3	-0.9	-0.1	-0.5	-0.3	-0.2
350130022	TERES	71.3	66.0	-0.3	-0.3	-0.7	-0.1	-0.5	-0.3	-0.2
350130023	SOLAN	65.0	60.2	-0.2	-0.2	-0.2	-0.2	-1.2	-0.7	-0.3
350151005	CARLS	69.0	66.4	-0.5	-0.5	-0.2	-0.1	-0.3	-0.2	-0.1
350171003	GRANT	62.0	58.9	0.0	0.0	0.0	0.0	-0.1	-0.1	0.0
350250008	HOBBS	66.0	63.3	-0.9	-1.1	-0.2	0.0	-0.3	-0.2	-0.1
350290003	DEAIR	66.0	62.5	-0.2	-0.1	-0.2	0.0	-0.6	-0.4	0.0

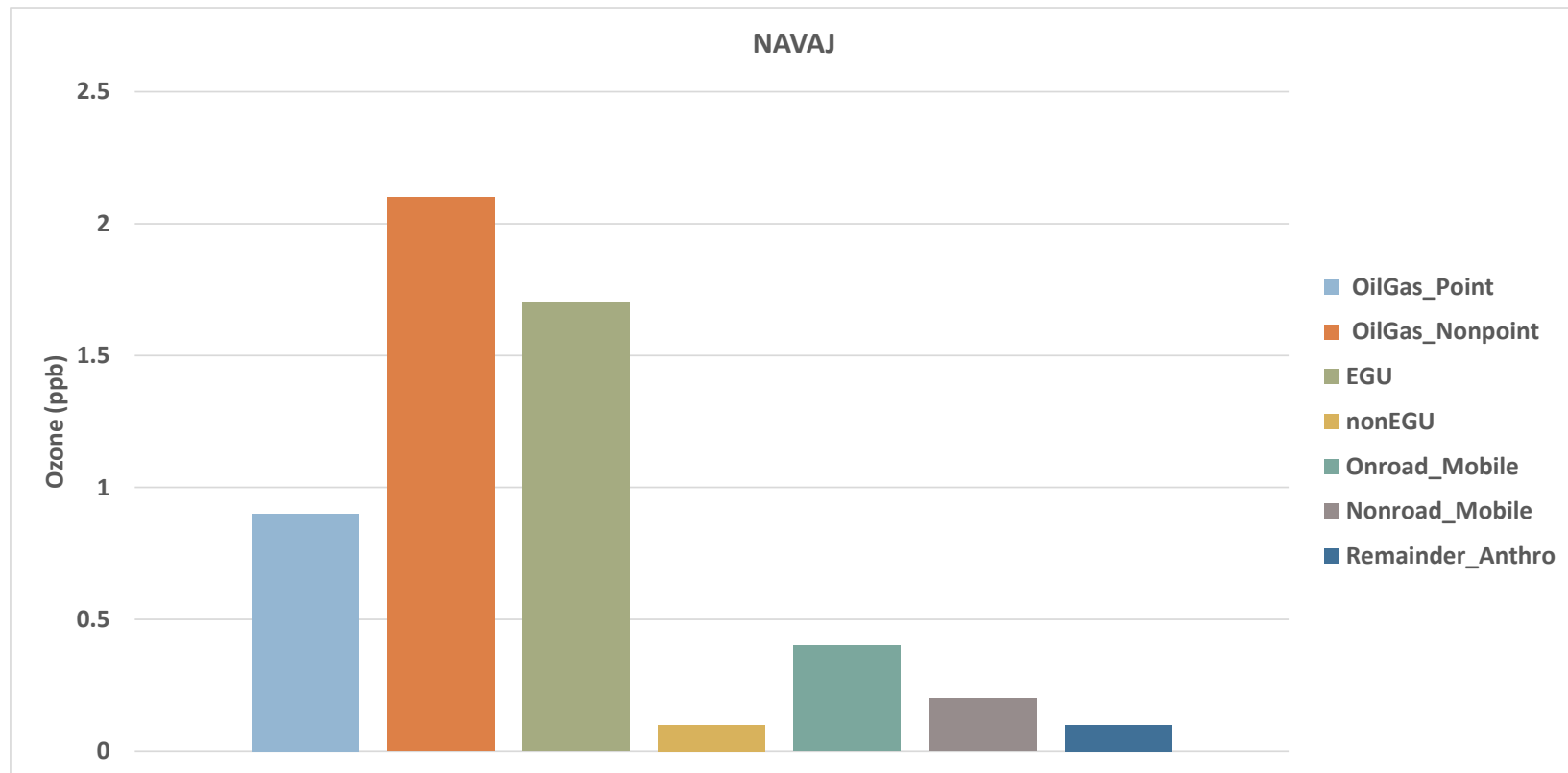


Figure 10-3. Contributions of New Mexico anthropogenic emissions from 7 Source Sectors to projected 2028 ozone DVFs at Navajo Lake in San Juan County.

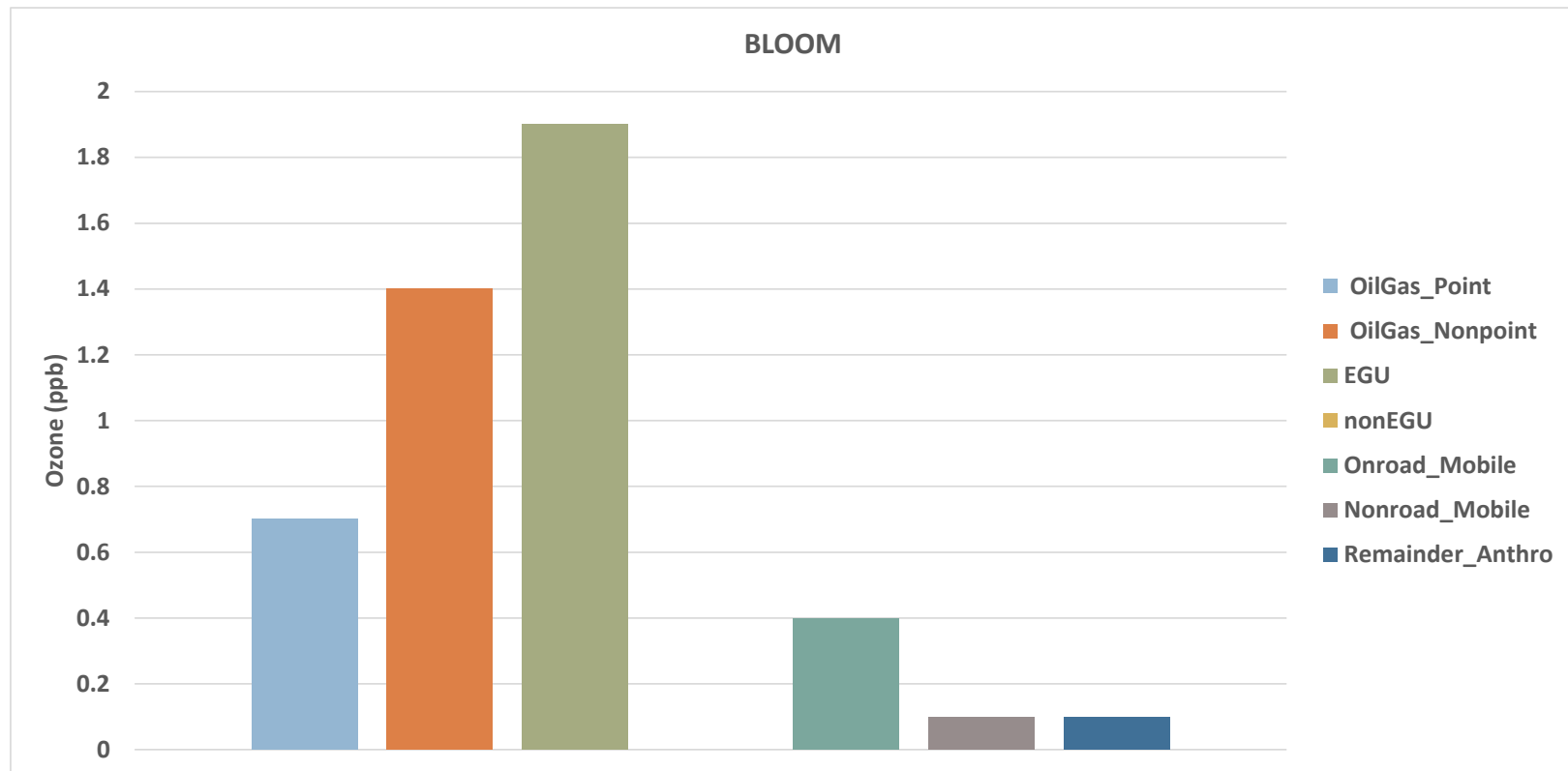


Figure 10-4. Contributions of New Mexico anthropogenic emissions from 7 Source Sectors to projected 2028 ozone DVFs at Bloomfield in San Juan County.

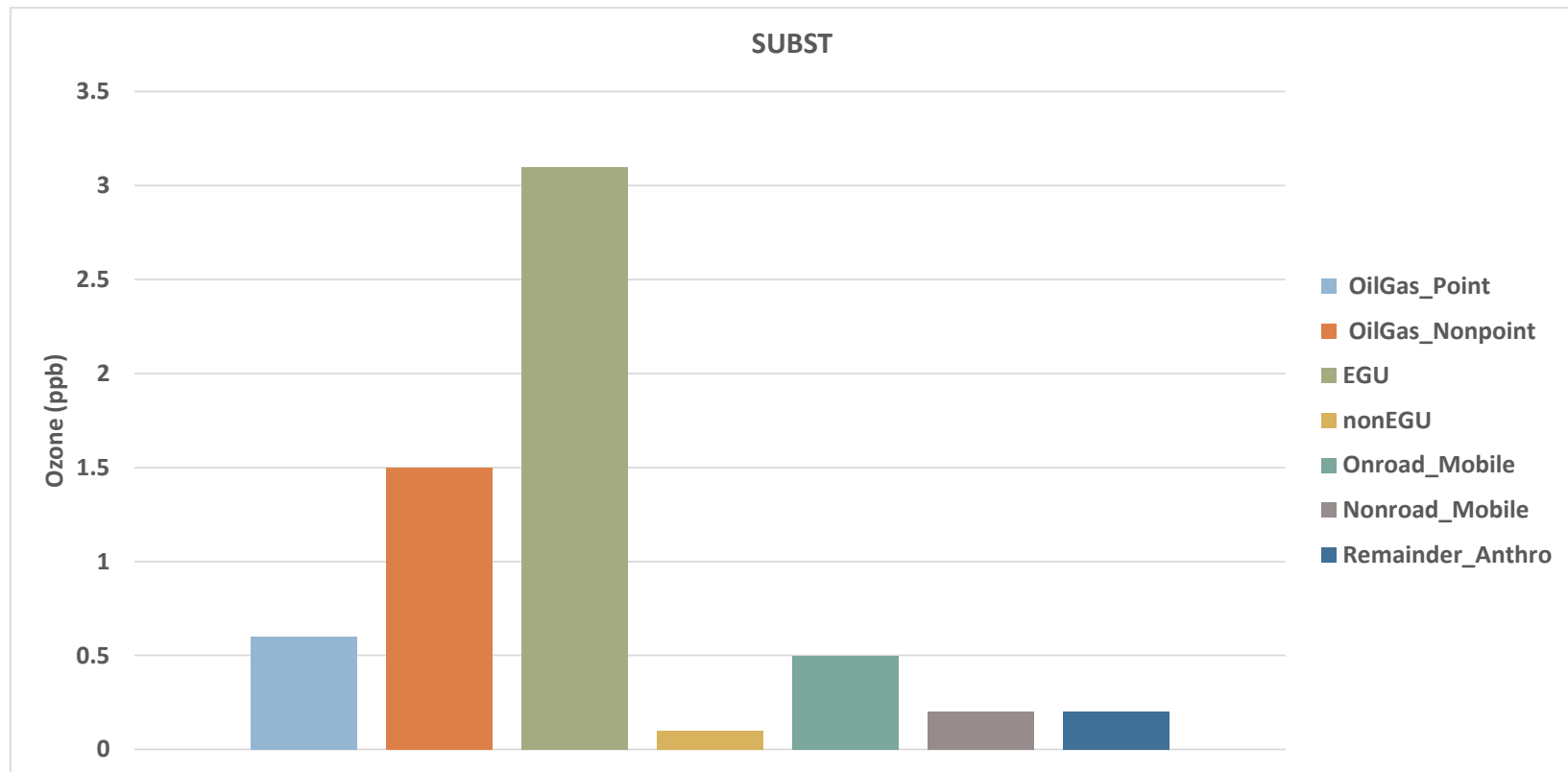


Figure 10-5. Contributions of New Mexico anthropogenic emissions from 7 Source Sectors to projected 2028 ozone DVFs at Substation in San Juan County.

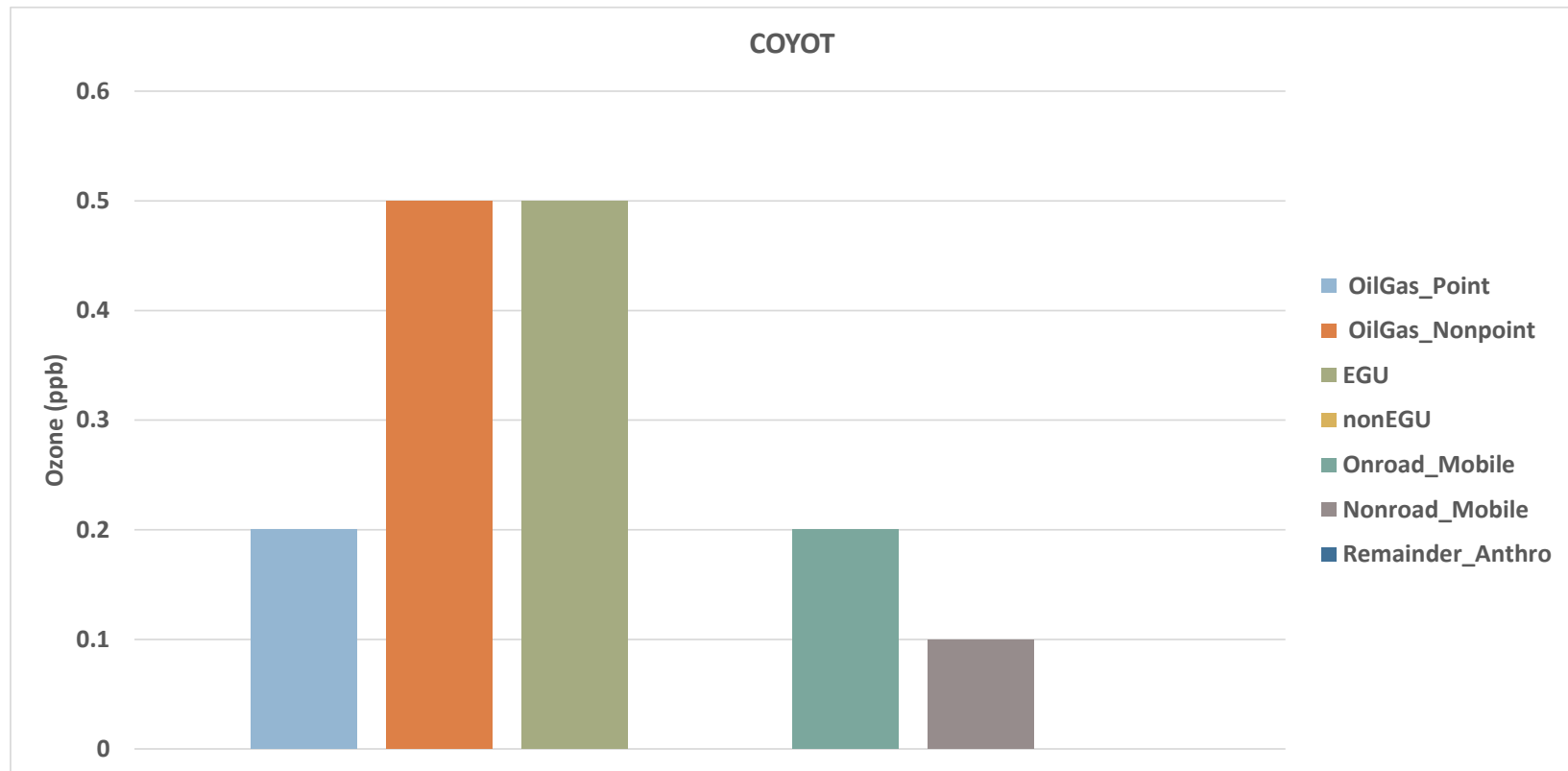


Figure 10-6. Contributions of New Mexico anthropogenic emissions from 7 Source Sectors to projected 2028 ozone DVFs at Coyote Ranger District in Rio Arriba County.

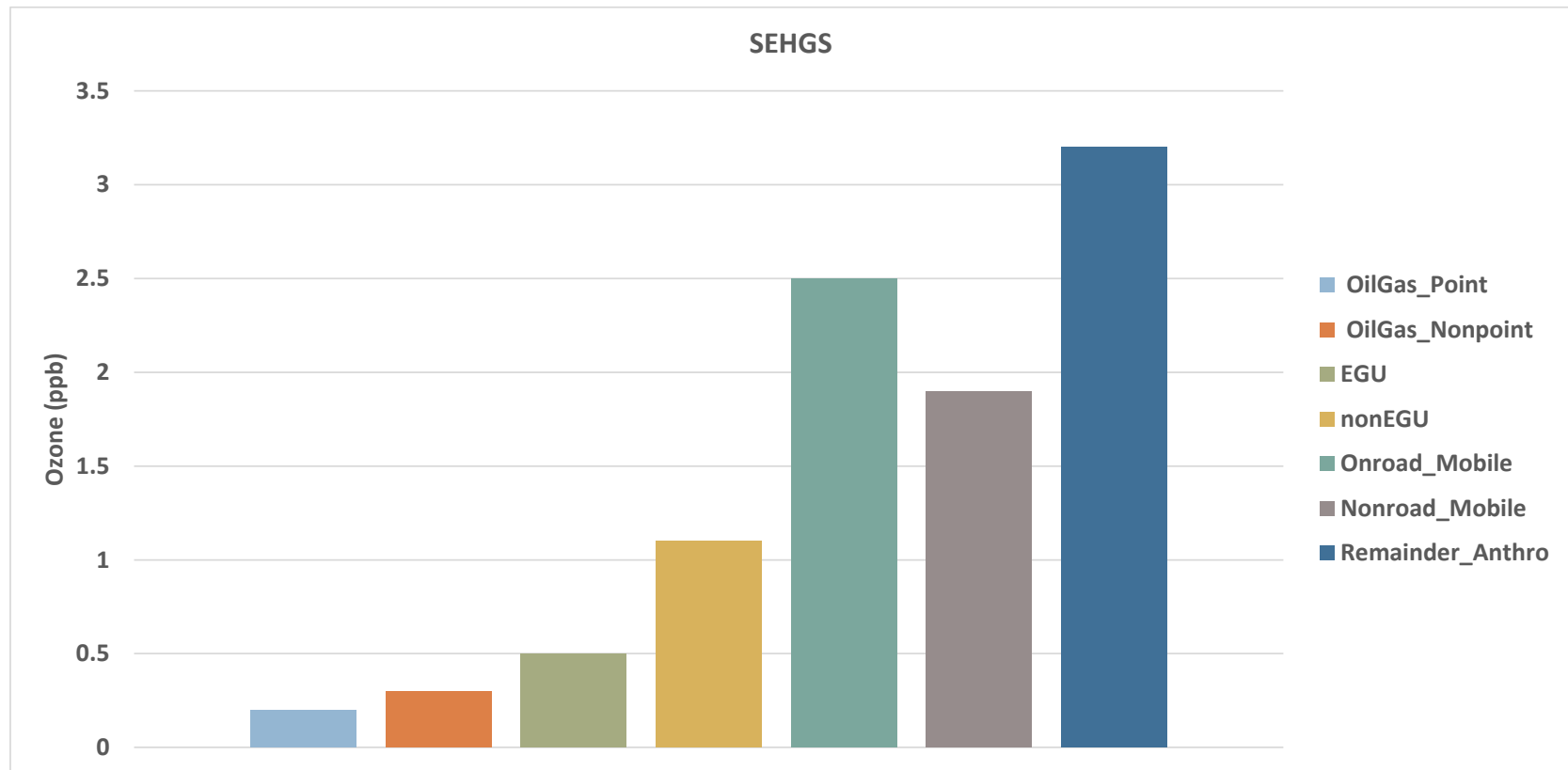


Figure 10-7. Contributions of New Mexico anthropogenic emissions from 7 Source Sectors to projected 2028 ozone DVFs at Southeast Heights in Bernalillo County.

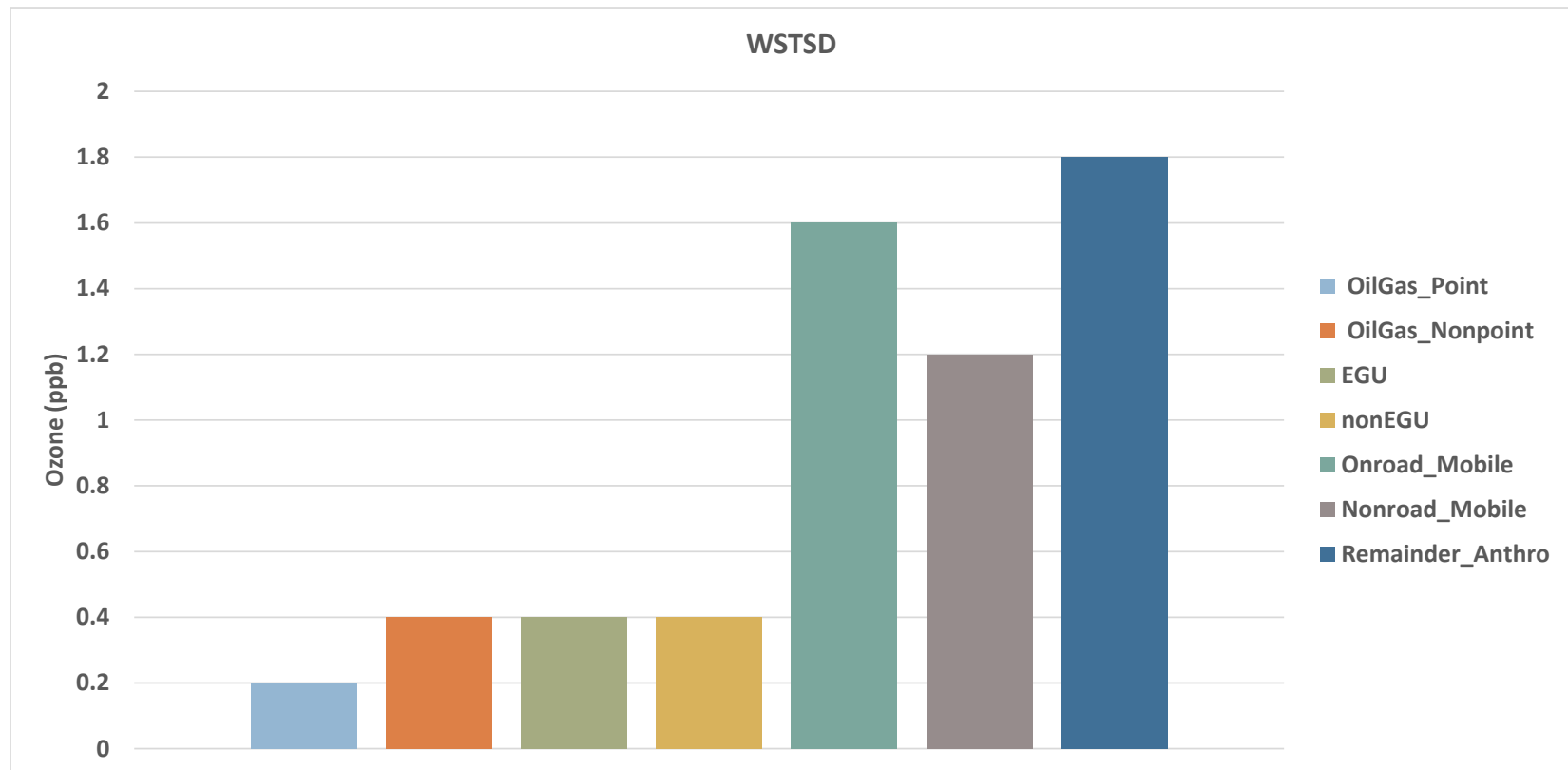


Figure 10-8. Contributions of New Mexico anthropogenic emissions from 7 Source Sectors to projected 2028 ozone DVFs at Westside in Bernalillo County.

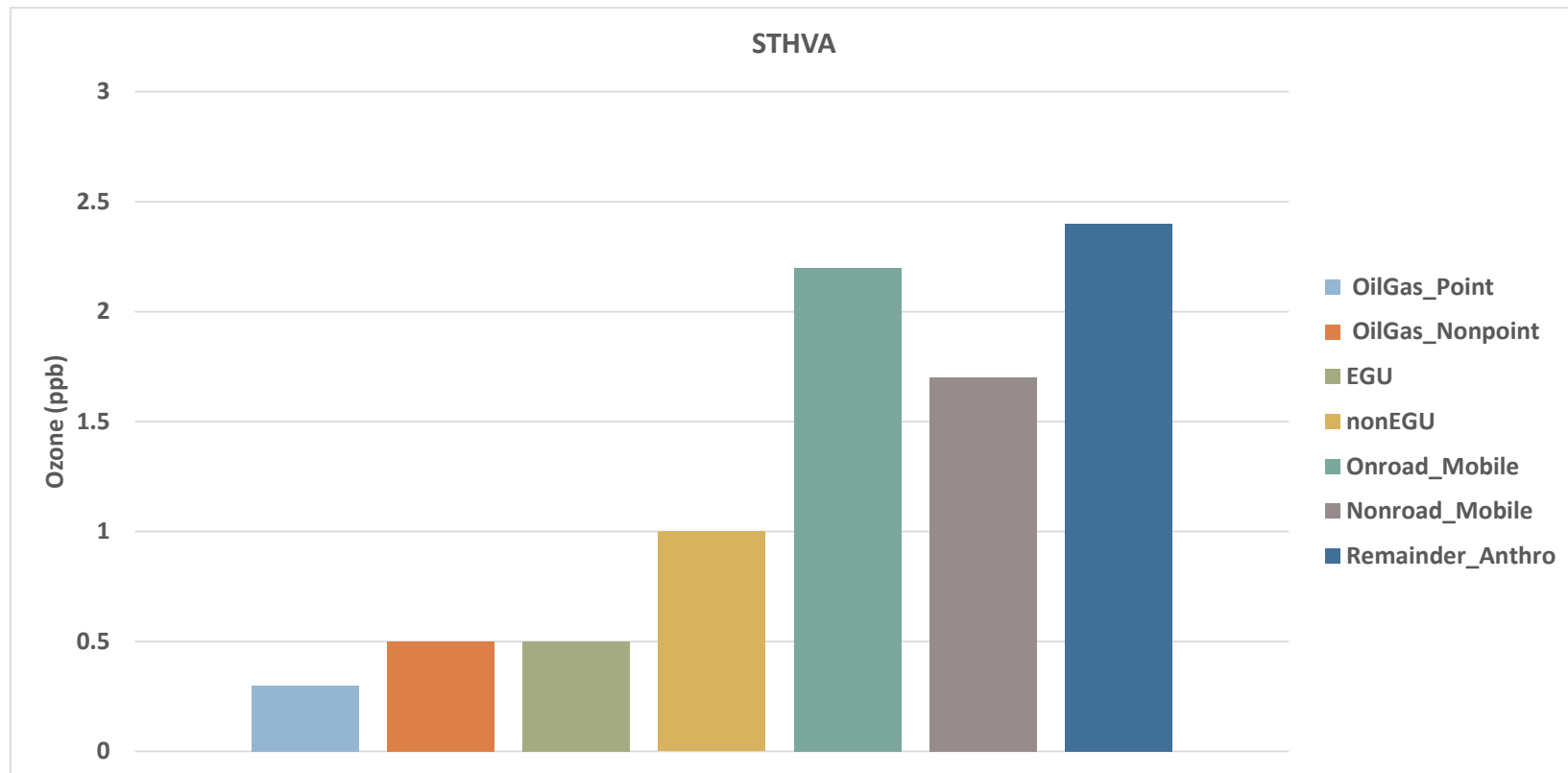


Figure 10-9. Contributions of New Mexico anthropogenic emissions from 7 Source Sectors to projected 2028 ozone DVFs at South Valley in Bernalillo County.

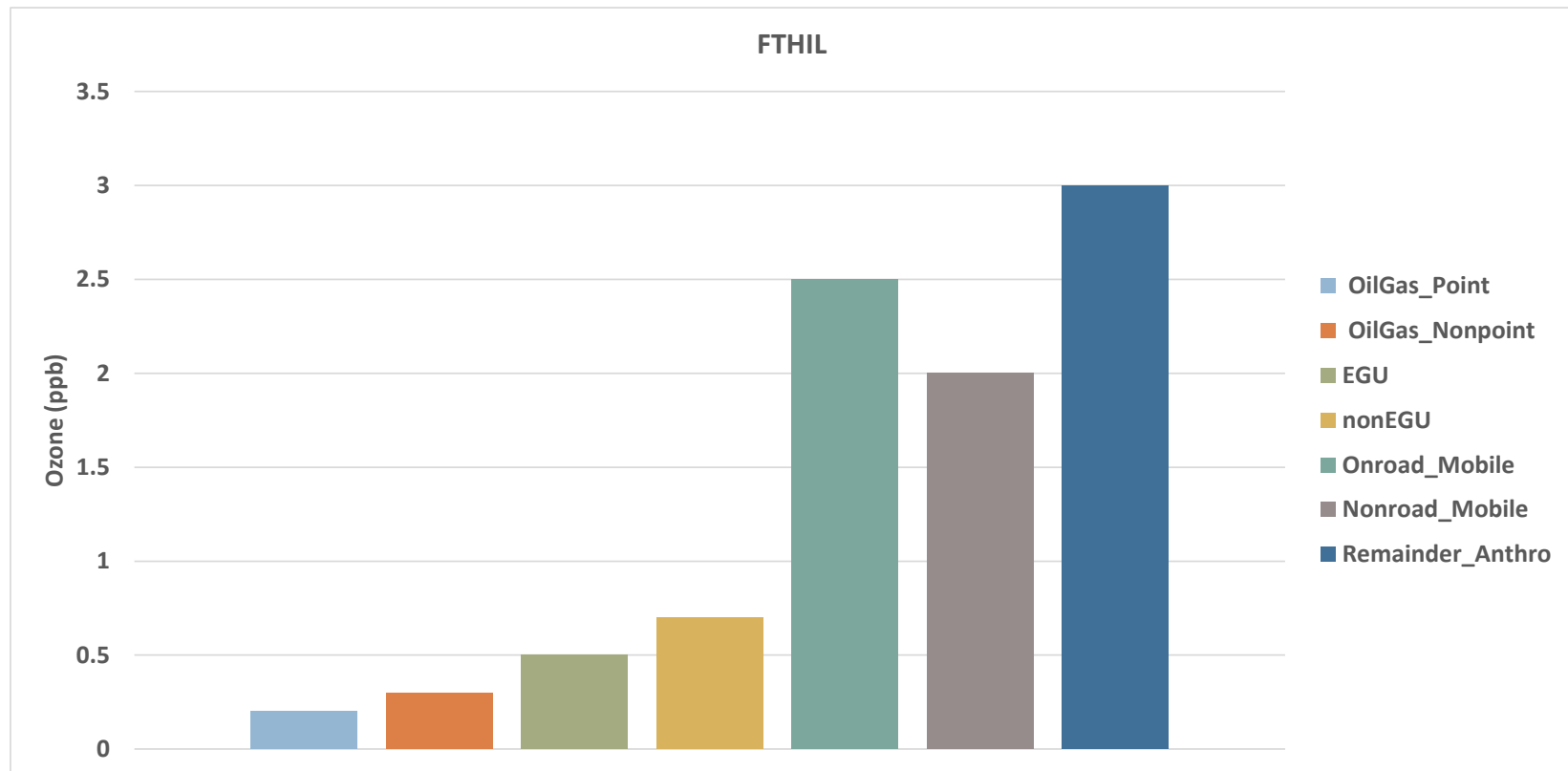


Figure 10-10. Contributions of New Mexico anthropogenic emissions from 7 Source Sectors to projected 2028 ozone DVFs at Foothills in Bernalillo County.

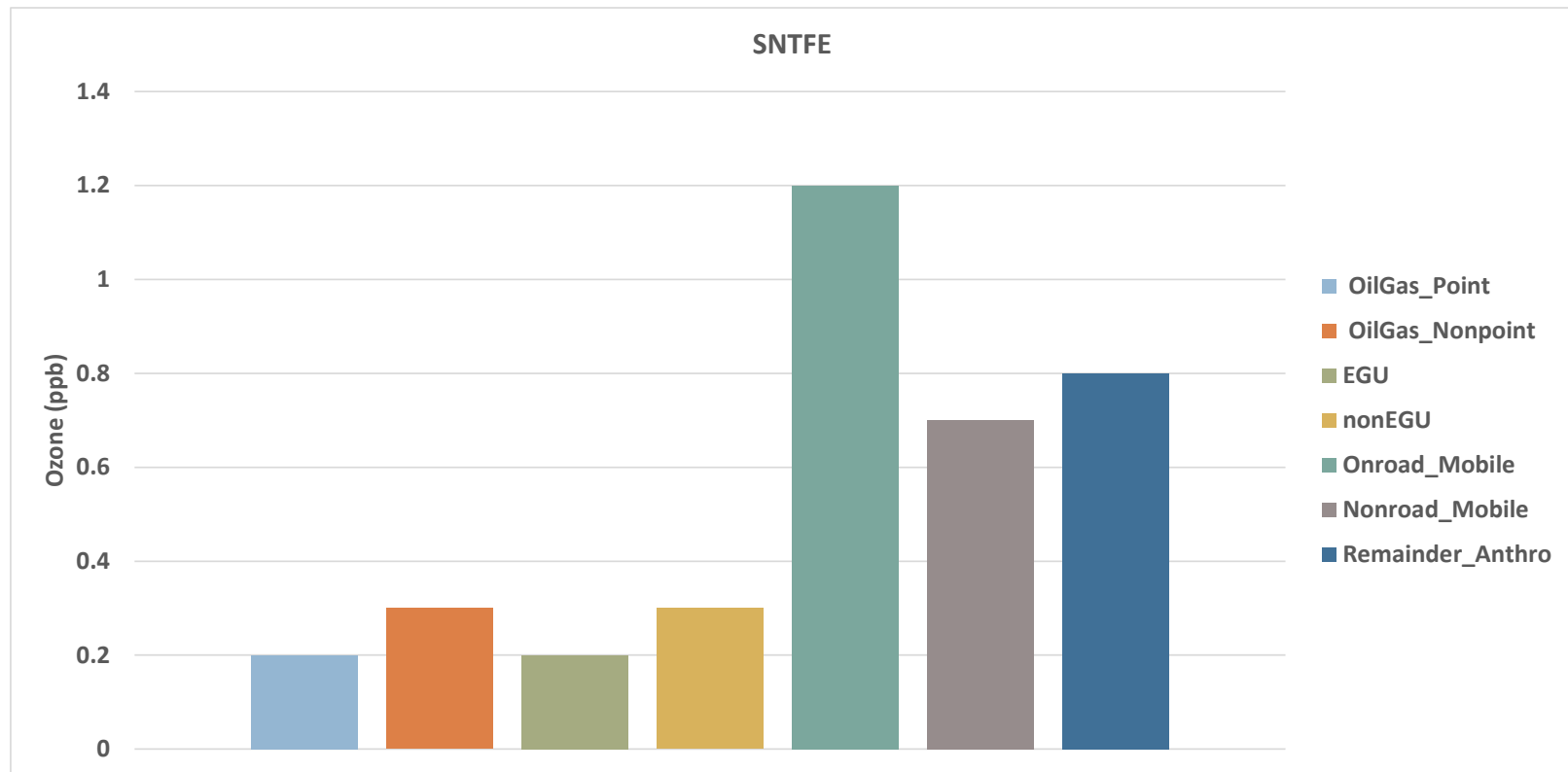


Figure 10-11. Contributions of New Mexico anthropogenic emissions for 7 Source Sectors to projected 2028 ozone DVFs at Santa Fe in Santa Fe County.

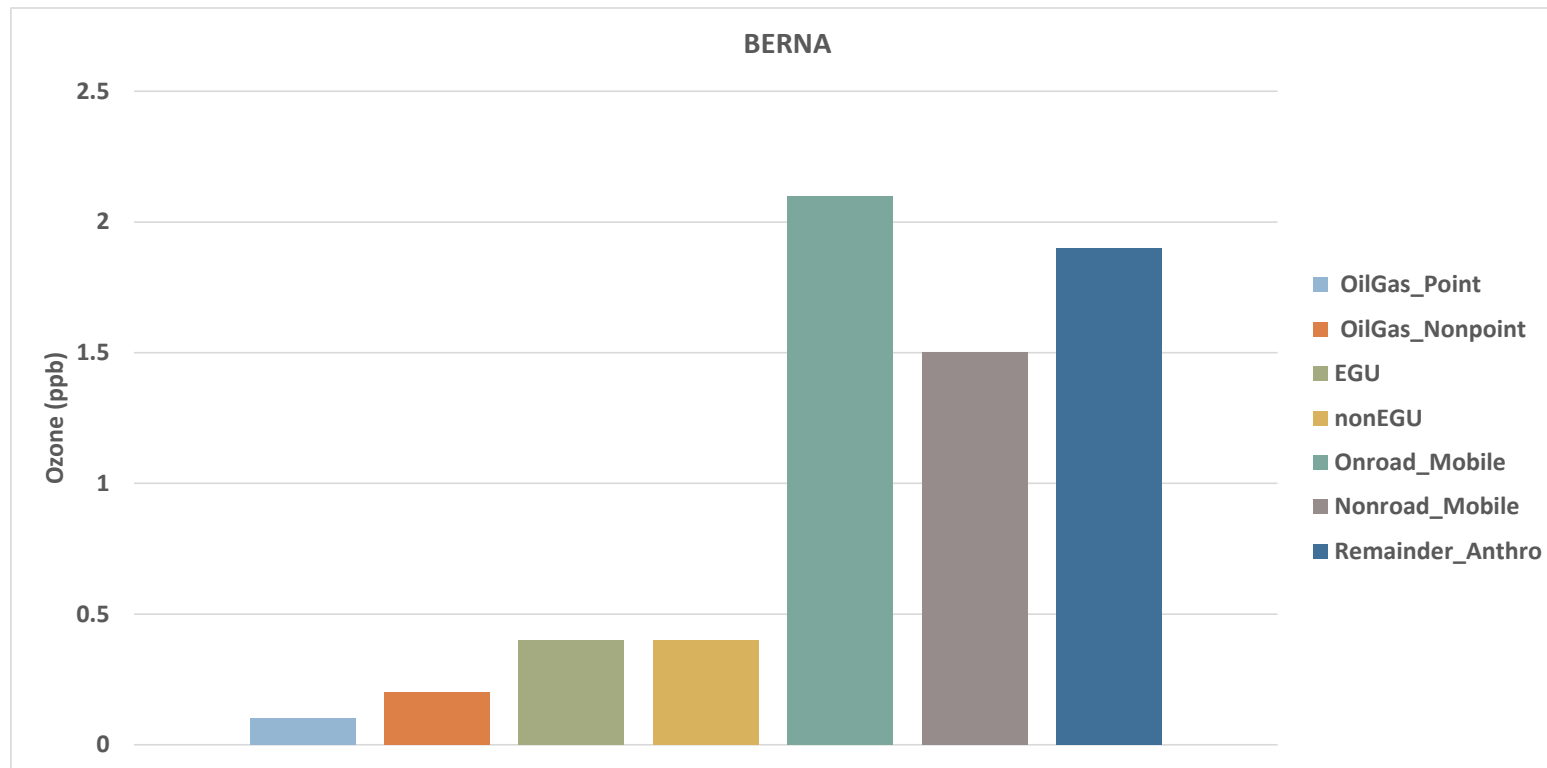


Figure 10-12. Contributions of New Mexico anthropogenic emissions from 7 Source Sectors to projected 2028 ozone DVFs at Bernalillo in Sandoval County.

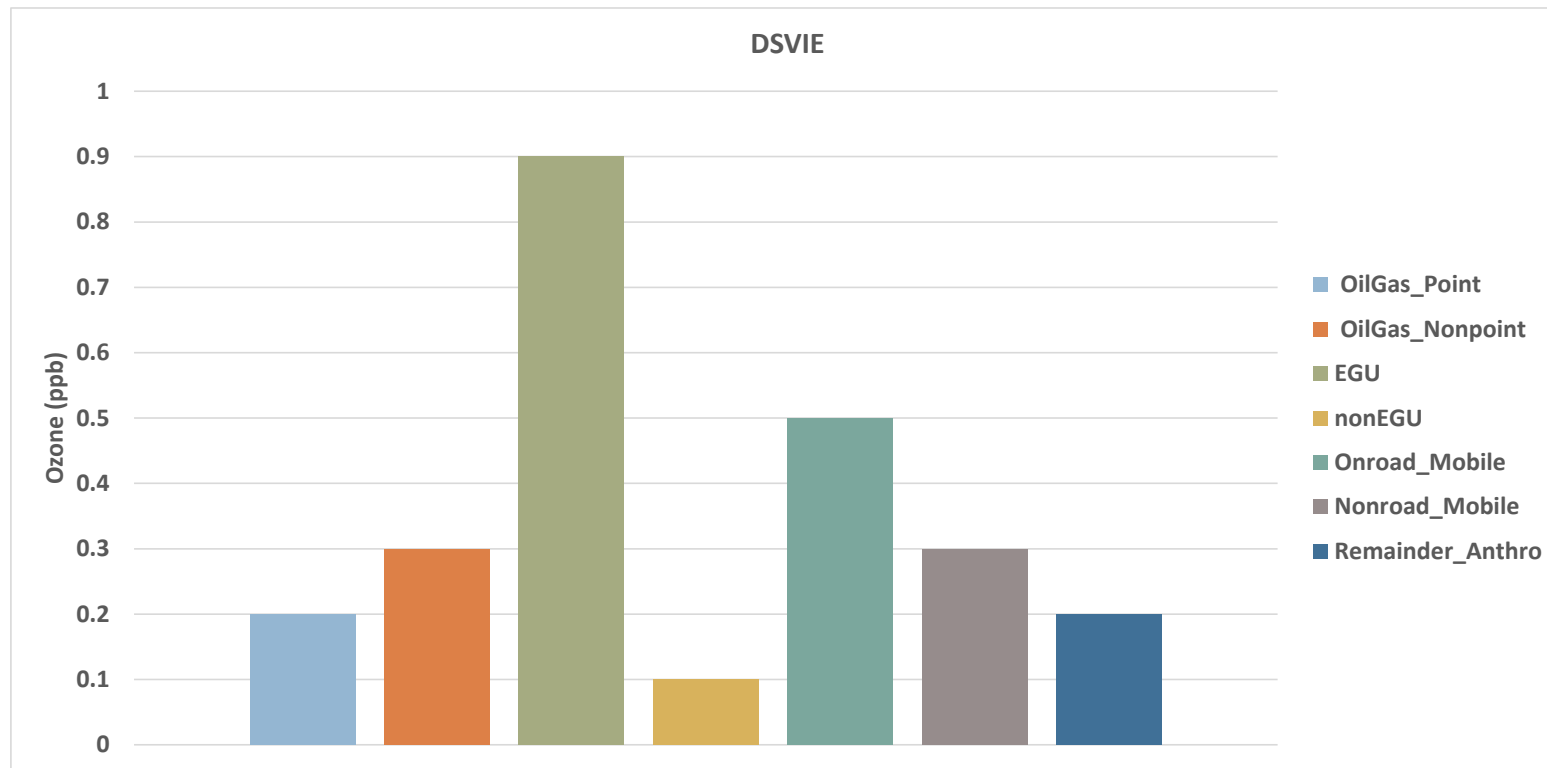


Figure 10-13. Contributions of New Mexico anthropogenic emissions from 7 Source Sectors to projected 2028 ozone DVFs at Desert View in Doña Ana County in southern New Mexico.

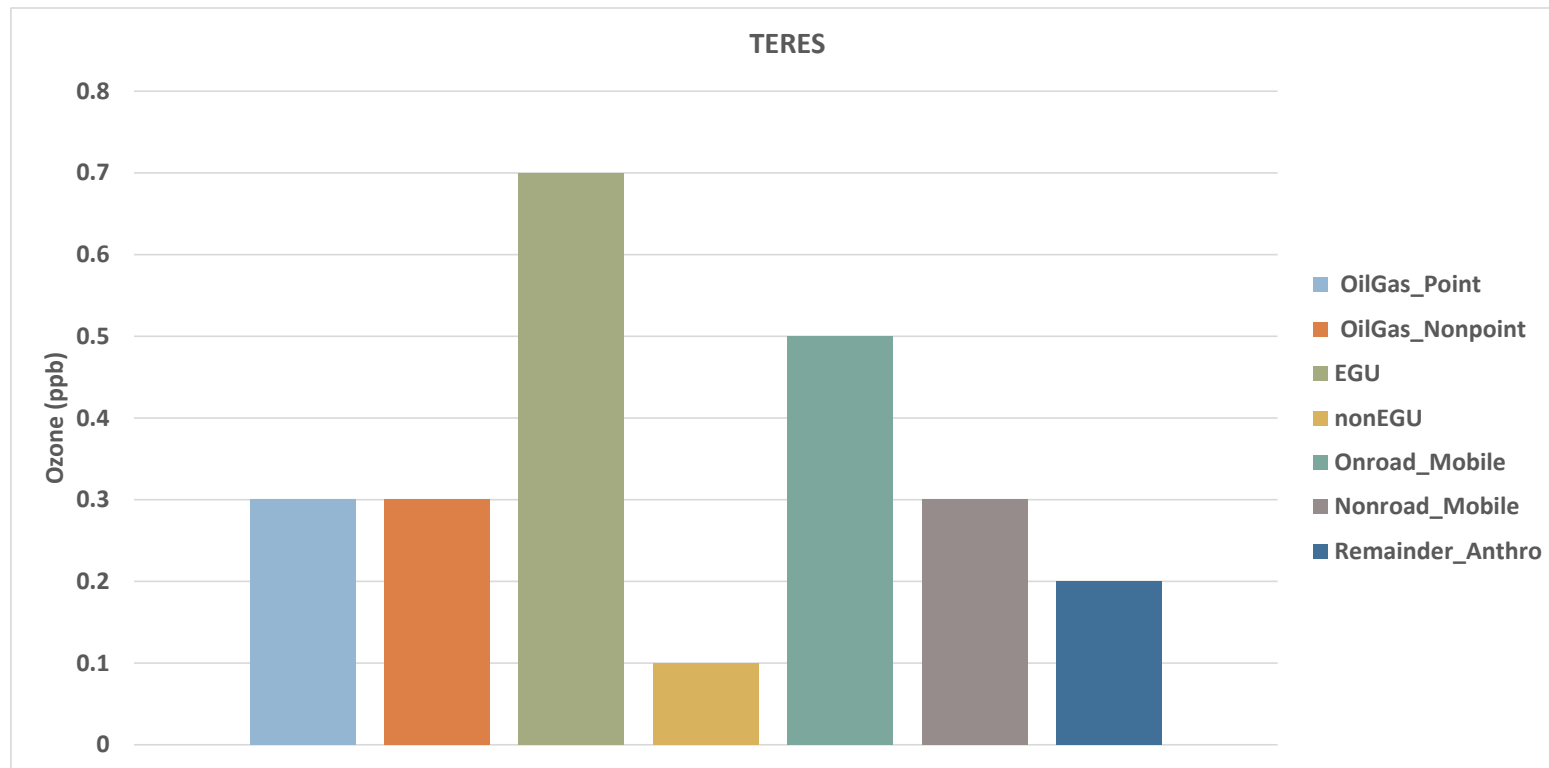


Figure 10-14. Contributions of New Mexico anthropogenic emissions for 7 Source Sectors to projected 2028 ozone DVFs at Santa Teresa in Doña Ana County in southern New Mexico.

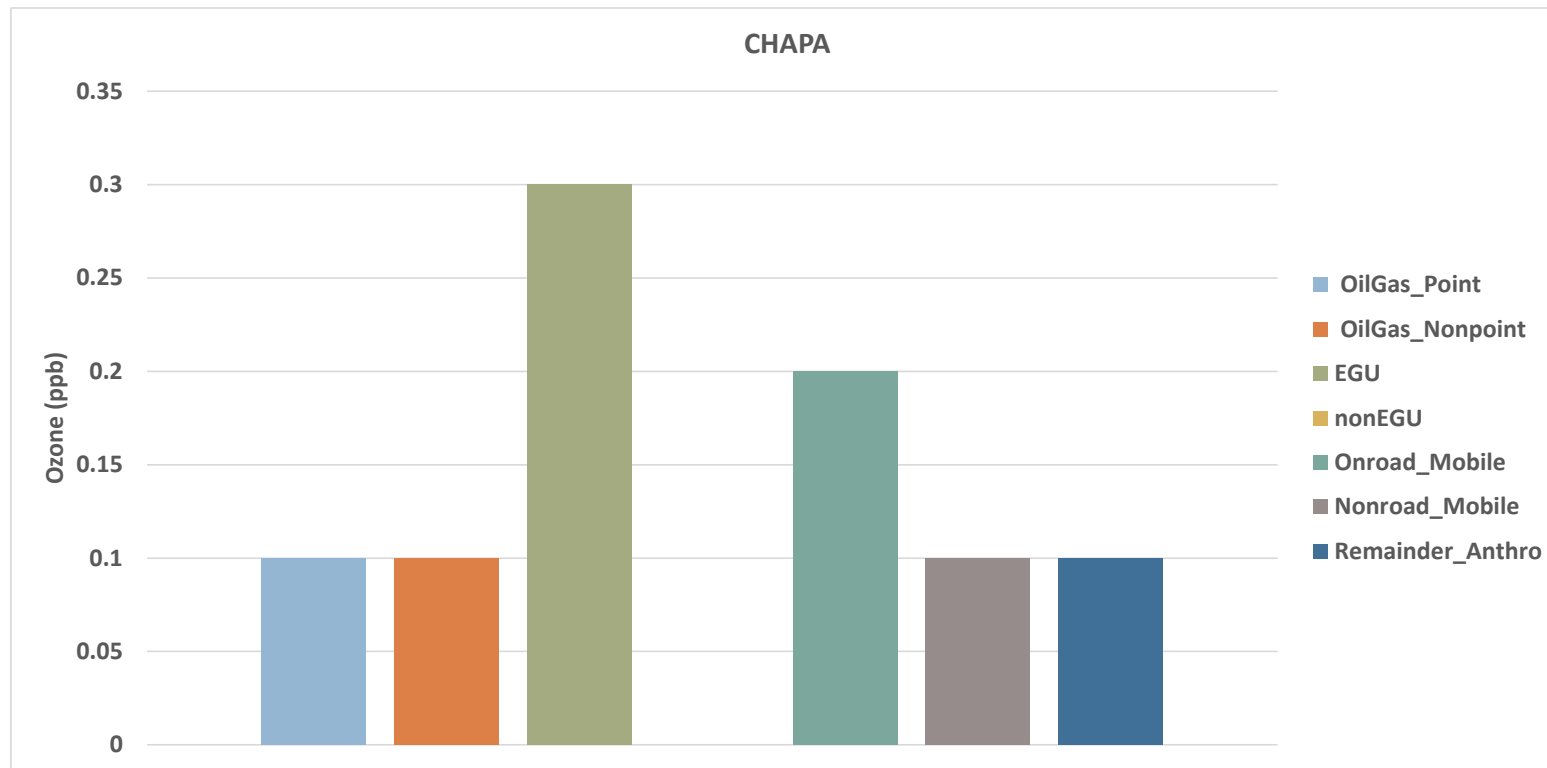


Figure 10-15. Contributions of New Mexico anthropogenic emissions for 7 Source Sectors to projected 2028 ozone DVFs at Chaparral in Doña Ana County in southern New Mexico.

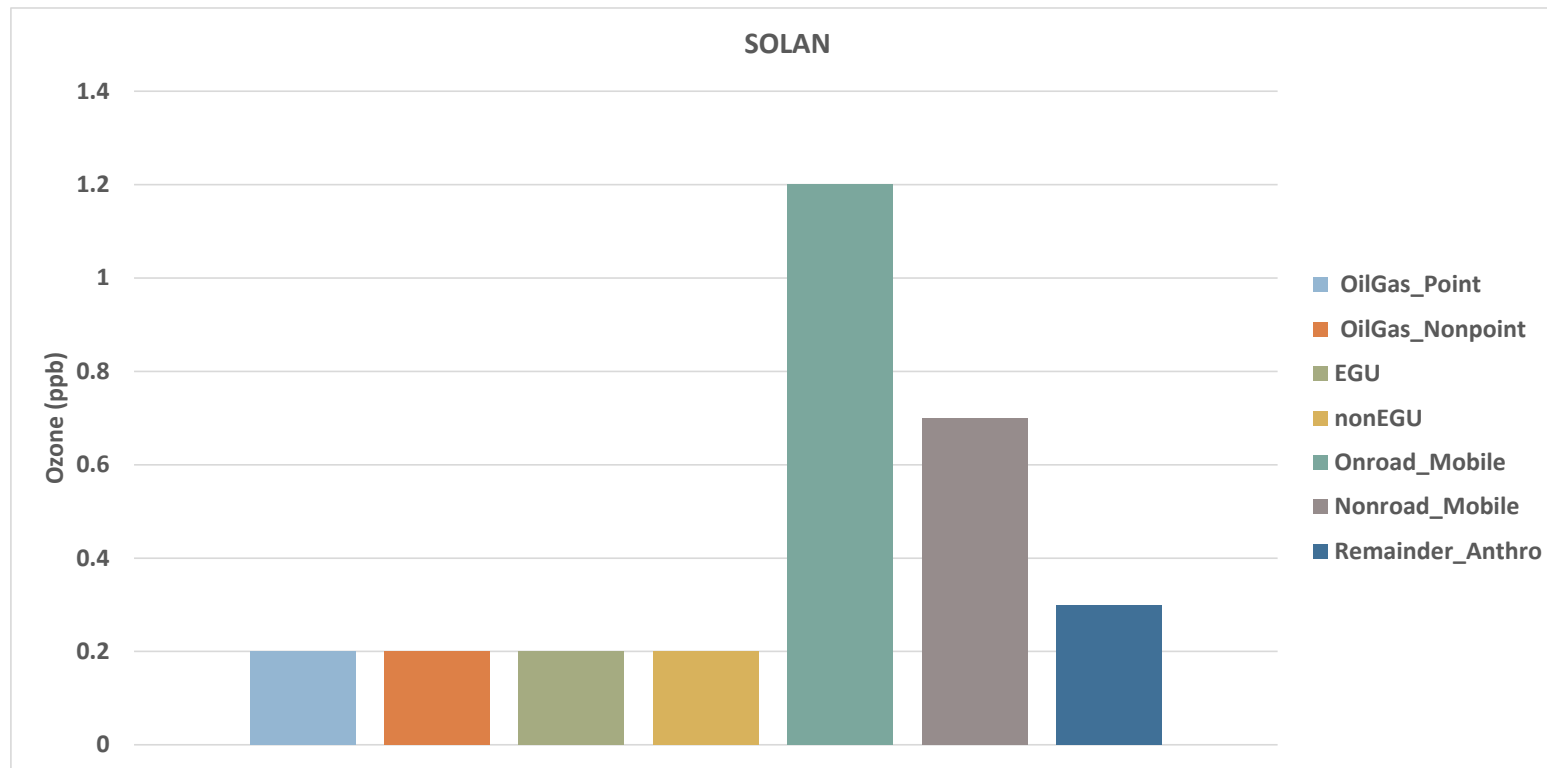


Figure 10-16. Contributions of New Mexico anthropogenic emissions for 7 Source Sectors to projected 2028 ozone DVFs at Solano in Doña Ana County in southern New Mexico.

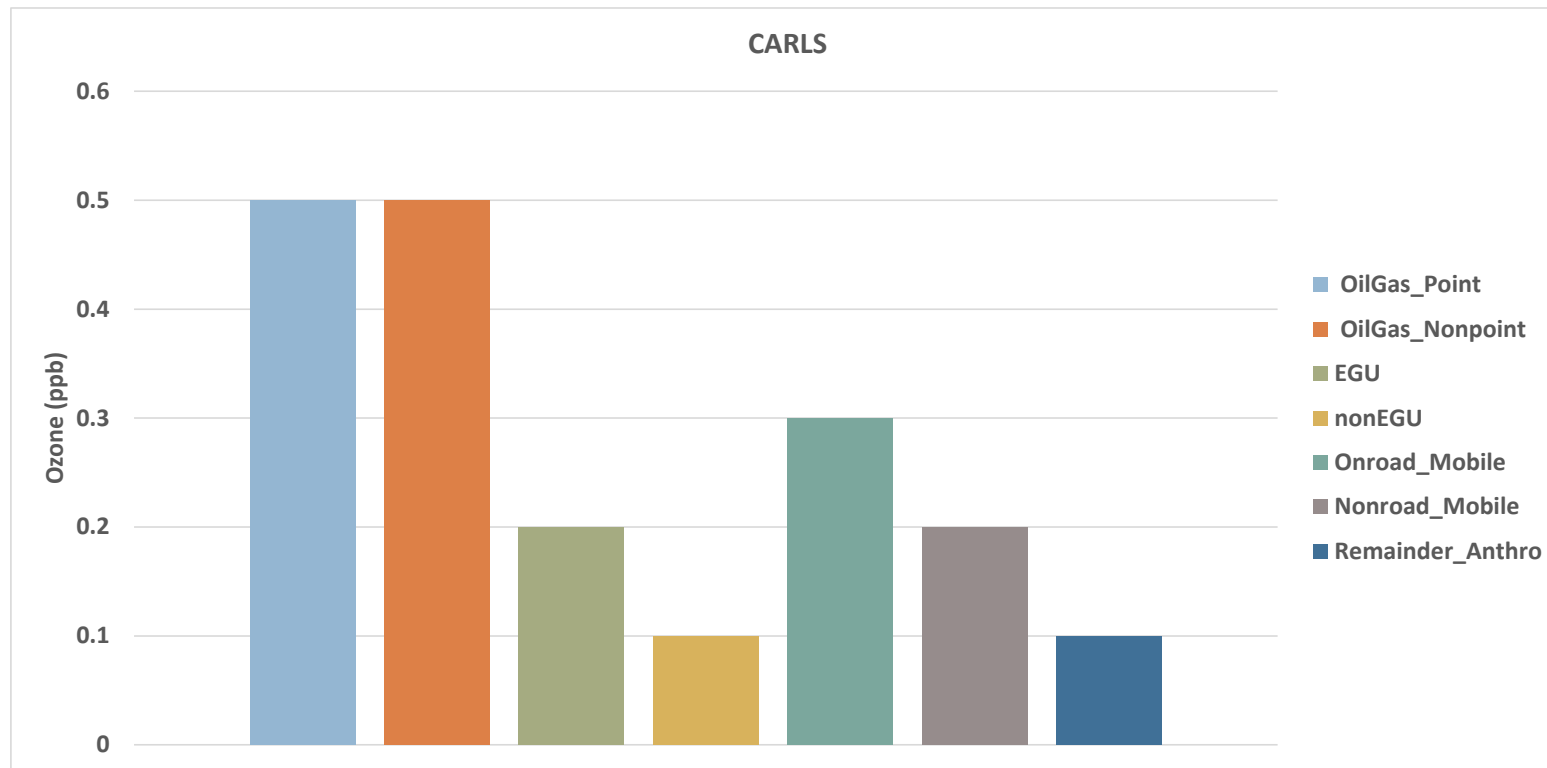


Figure 10-17. Contributions of New Mexico anthropogenic emissions for 7 Source Sectors to projected 2028 ozone DVFs at Carlsbad in Eddy County in southeastern New Mexico.

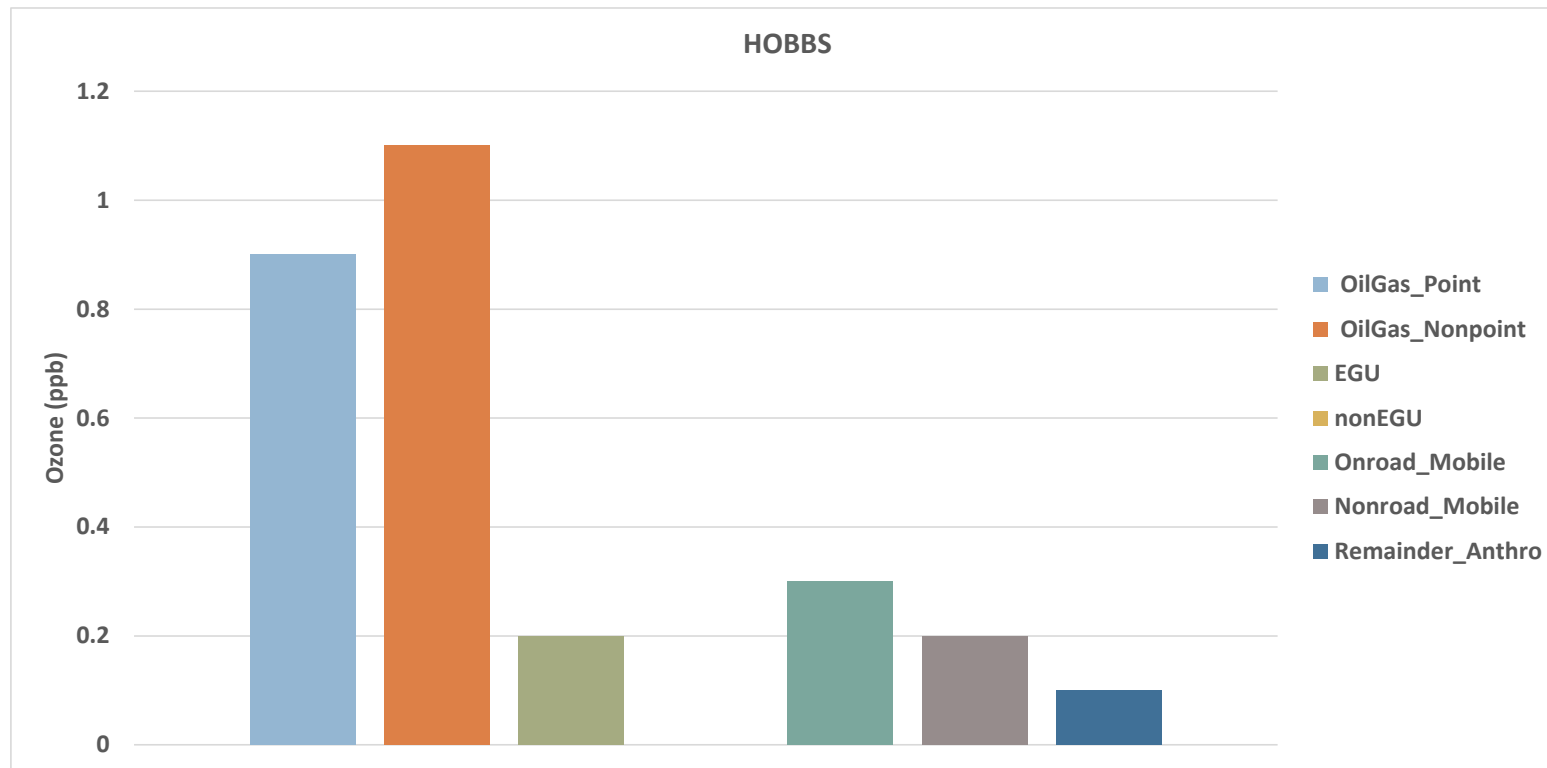


Figure 10-18. Contributions of New Mexico anthropogenic emissions for 7 Source Sectors to projected 2028 ozone DVFs at Hobbs in Lea County in southeastern New Mexico.

The SMAT Unmonitored Area Analysis (UAA) feature was used to estimate the spatial distribution 2028 ozone DVFs across the 4-km New Mexico domain for the 2028 O&G Control Scenario without New Mexico emissions from each of the 7 anthropogenic emission Source Sectors. Figures 10-19 and 10-20 display the reduction in 2028 ozone DVFs across the New Mexico 4-km domain due to the removal of New Mexico emissions for the 7 Source Sectors. Removing New Mexico EGU emissions reduces the 2028 ozone DVF by as much as 3.1 ppb in San Juan County with ozone reductions of 0.1 to 1.0 ppb in the upper half of New Mexico and from Doña Ana to Lea Counties in southern New Mexico (Figure 10-19a). The removal of New Mexico Non-EGU Point emissions results in a reduction of 1.3 ppb in eastern Bernalillo County and reductions of 0.1 to 1.0 in adjacent counties, with little effect over the rest of New Mexico away from Bernalillo County (Figure 10-19b).

New Mexico On-Road mobile contributes as much as 2.6 ppb to the 2028 ozone DVF with reductions of 1-2 ppb stretching from Albuquerque to Santa Fe and in Las Cruces (Figure 10-19c). New Mexico Non-Road mobile contributes as much as 2.1 ppb in Bernalillo County (Figure 10-19d).

New Mexico Non-Point O&G has large (> 2 ppb) contributions to the 2028 ozone DVF in the San Juan and Permian Basins (Figure 10-20a). Whereas, New Mexico Point O&G contributes as much as 1-2 ppb in the Permian Basin but less than 1 ppb in the San Juan Basin (Figure 10-20b). The Other Anthropogenic Source Sector contributions has a similar distribution as the two mobile Source Sectors with the highest ozone contributions centered on Bernalillo County (Figure 10-20c).

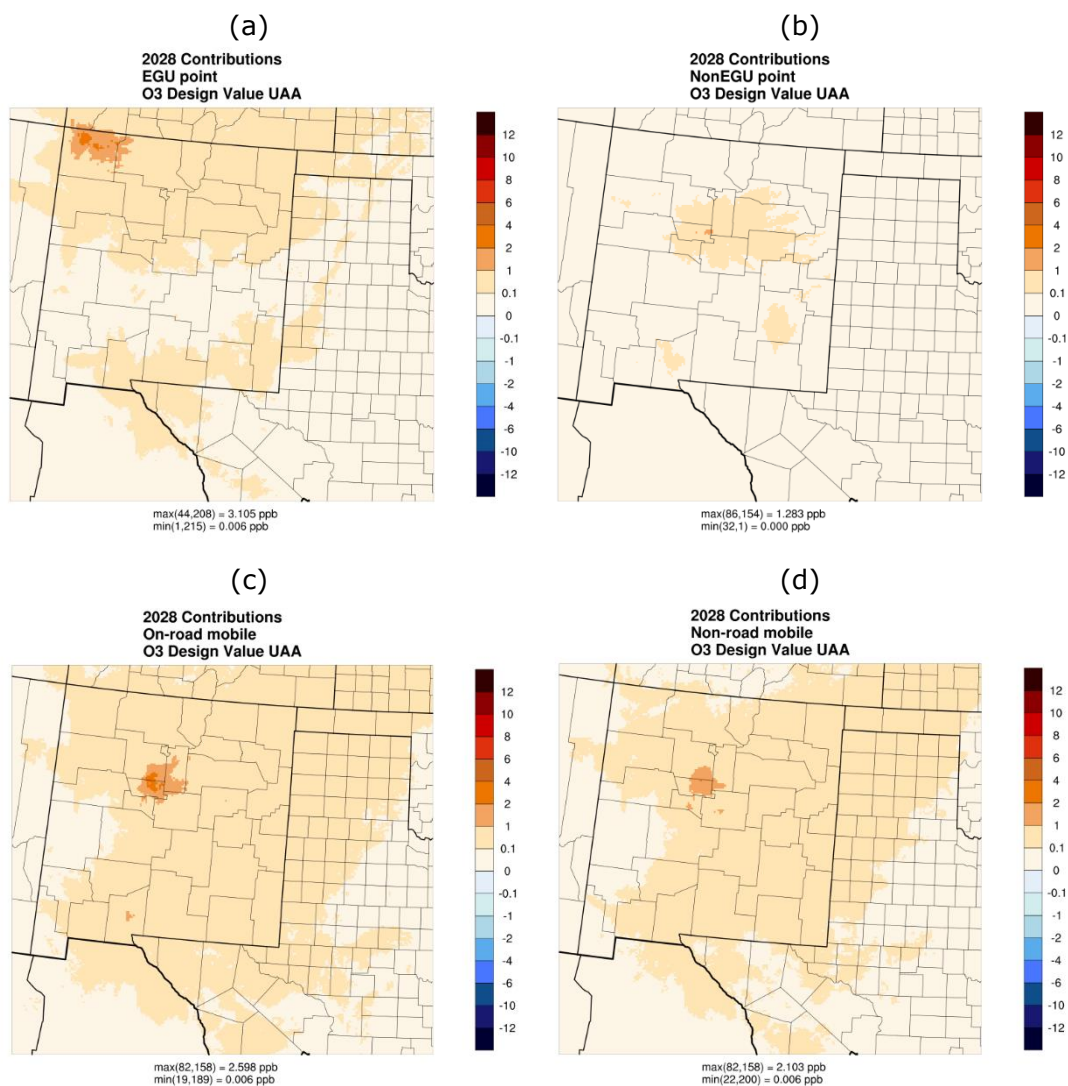


Figure 10-19. Reduction in 2028 ozone DVF due to removal of New Mexico Source Sector emissions for: (a) EGU Point; (b) Non-EGU Point; (c) On-Road Mobile; and (d) Non-Road Mobile.

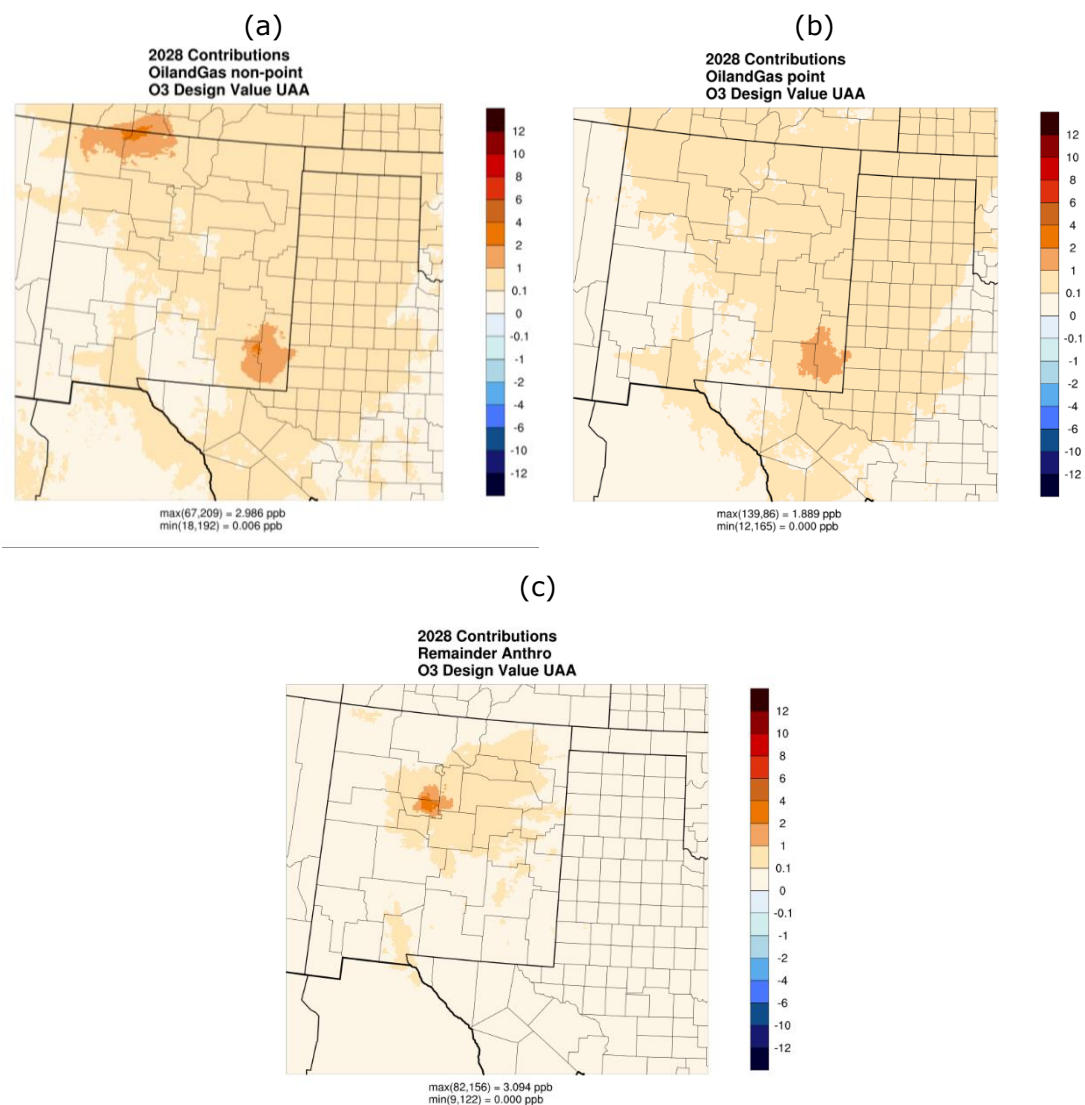


Figure 10-20. Reduction in 2028 ozone DVF due to removal of New Mexico Source Sector emissions for: (a) Non-Point O&G; (b) Point O&G; and (c) Other Anthropogenic.

10.3.1.2 United States Source Sector 2028 Ozone DVF Contributions

Table 10-2 displays the reductions in 2028 ozone DVFs due to the elimination of Source Sector emissions throughout the United States. Table 10-3 shows the percent of the all U.S. Source Sector ozone reduction that was due to just the Source Sector emissions in New Mexico (i.e., the percent the ozone reductions in Table 10-1 are of the ozone reductions in Table 10-2). At the three San Juan County sites, O&G non-point contributes the most (2-3 ppb) with approximately 60-78% coming from O&G non-point sources in New Mexico. Oil and gas point contributes 1.1 to 1.3 ppb at the three San Juan County sites with 55-69% coming from sources in New Mexico. The U.S. EGU Source Sector contributes 2.0 to 3.6 ppb to the 2028 ozone DVF at the three San Juan County sites with a vast majority (~85%) coming from New Mexico. On the other hand, the U.S. On-Road (1.7 ppb) and Non-Road (1.2 ppb) contribution at the three San Juan County sites comes mostly from outside of New Mexico (10-30%).

For sites in Bernalillo County in central New Mexico, 40% to 86% of the U.S. Source Sector contributions come from sources within New Mexico. The largest U.S. Source Sector contributions are for On-Road (3-4 ppb) and Non-Road (2-3 ppb) for which 60-70% of the contribution is due to sources from New Mexico.

At the Doña Ana County monitoring sites, approximately 25% (13-38%) of the U.S. O&G and 22-50% of the U.S. EGU Source Sector is from New Mexico. However, only 9-17% of the U.S. On-Road ozone contribution is from New Mexico sources with the exception of Solano that has 44% of the U.S. on-road mobile ozone contribution due to New Mexico on-road emissions. .

The Carlsbad and Hobbs monitors in southeast New Mexico have approximately half of their U.S. O&G ozone contributions from New Mexico sources, with only ~20% of U.S. mobile contribution coming from New Mexico.

The Grant monitor in southwest New Mexico has almost no ozone contributions from sources in New Mexico.

Table 10-2. Reduction in 2028 ozone DVF due to the elimination of emissions from 7 Source Sectors in United States.

AQS_ID	Site_ID	DVC	DVF	O&GPT	O&GNP	EGU	NonEGU	On-Road	Non-Road	OAnth
Northern New Mexico										
350390026	COYOT	64.0	60.0	-0.5	-0.9	-0.8	-0.7	-1.5	-1.0	-0.7
350450009	BLOOM	64.3	60.2	-1.1	-2.1	-2.3	-0.7	-1.7	-1.1	-0.6
350450018	NAVAJ	67.0	63.3	-1.3	-2.7	-2.0	-0.8	-1.7	-1.2	-0.8
350451005	SUBST	63.7	59.6	-1.1	-2.5	-3.6	-0.8	-1.7	-1.2	-0.7
Central New Mexico										
350010023	NORTE	66.3	60.7	-0.5	-0.7	-1.1	-1.7	-3.9	-3.0	-4.2
350010024	SEHGS	68.0	62.0	-0.5	-0.7	-1.0	-1.7	-3.6	-2.8	-3.7
350010029	STHVA	66.0	60.5	-0.6	-0.9	-1.0	-1.6	-3.3	-2.5	-2.9
350010032	WSTSD	67.0	62.1	-0.4	-0.7	-0.9	-1.0	-2.7	-2.0	-2.4
350011012	FTHIL	65.0	58.8	-0.5	-0.7	-1.1	-1.4	-3.8	-3.0	-3.7
350431001	BERNA	64.0	58.1	-0.4	-0.6	-0.8	-1.1	-3.4	-2.5	-2.6
350490021	SNTFE	64.3	60.4	-0.5	-0.7	-0.7	-0.7	-2.0	-1.4	-1.3
Southern New Mexico										
350130008	UNION	66.3	59.8	-0.8	-0.9	-1.6	-1.5	-3.2	-2.3	-1.5
350130017	SPARK	67.0	61.8	-0.7	-1.0	-1.8	-1.5	-3.0	-2.1	-1.7
350130020	CHAPA	67.0	62.2	-0.6	-0.8	-1.3	-1.4	-2.3	-1.7	-1.3
350130021	DSVIE	72.0	66.8	-0.8	-1.1	-1.8	-1.6	-3.1	-2.2	-1.8
350130022	TERES	71.3	66.0	-0.8	-1.1	-1.6	-1.5	-2.9	-2.1	-1.5
350130023	SOLAN	65.0	60.2	-0.7	-1.0	-0.9	-1.1	-2.7	-1.8	-1.1
350151005	CARLS	69.0	66.4	-0.8	-1.1	-0.5	-0.8	-1.3	-0.9	-0.7
350171003	GRANT	62.0	58.9	-0.2	-0.3	-0.4	-0.7	-1.3	-1.0	-0.7
350250008	HOBBS	66.0	63.3	-1.6	-2.2	-0.7	-0.6	-1.4	-1.0	-0.7
350290003	DEAIR	66.0	62.5	-0.4	-0.5	-0.6	-0.7	-1.7	-1.2	-0.7

Table 10-3. Percent contribution of New Mexico Source Sectors to All United Source Sectors reduction in 2028 ozone DVF.

AQS_ID	Site_ID	O&GPT	O&GNP	EGU	NonEGU	On-Road	Non-Road	OAnth
Northern New Mexico								
350390026	COYOT	40%	56%	63%	0%	13%	10%	0%
350450009	BLOOM	64%	67%	83%	0%	24%	9%	17%
350450018	NAVAJ	69%	78%	85%	13%	24%	17%	13%
350451005	SUBST	55%	60%	86%	13%	29%	17%	29%
Central New Mexico								
350010023	NORTE	40%	43%	45%	59%	69%	67%	86%
350010024	SEHGS	40%	43%	50%	65%	69%	68%	86%
350010029	STHVA	50%	56%	50%	63%	67%	68%	83%
350010032	WSTSD	50%	57%	44%	40%	59%	60%	75%
350011012	FTHIL	40%	43%	45%	50%	66%	67%	81%
350431001	BERNA	25%	33%	50%	36%	62%	60%	73%
350490021	SNTFE	40%	43%	29%	43%	60%	50%	62%
Southern New Mexico								
350130008	UNION	25%	22%	44%	0%	16%	13%	7%
350130017	SPARK	29%	20%	50%	0%	13%	10%	12%
350130020	CHAPA	17%	13%	23%	0%	9%	6%	8%
350130021	DSVIE	25%	27%	50%	6%	16%	14%	11%
350130022	TERES	38%	27%	44%	7%	17%	14%	13%
350130023	SOLAN	29%	20%	22%	18%	44%	39%	27%
350151005	CARLS	63%	45%	40%	13%	23%	22%	14%
350171003	GRANT	0%	0%	0%	0%	8%	10%	0%
350250008	HOBBS	56%	50%	29%	0%	21%	20%	14%
350290003	DEAIR	50%	20%	33%	0%	35%	33%	0%

10.3.2 Source Sector Contributions to Modeled MDA8 Ozone Concentrations

The contributions of the Source Sector emissions to the absolute CAMx modeling results 2028 daily MDA8 ozone concentrations are analyzed in this section. We first present spatial maps of the episode maximum MDA8 ozone contributions across the 4-km New Mexico domain for each Source Region. The contributions of all and New Mexico Source Sectors to MDA8 ozone concentrations are then presented at four example New Mexico monitoring sites for the 10 days used to make the 2028 ozone DVF projections (i.e., the 10 SMAT days). Finally, the spatial maps of New Mexico and all United States Source sector contributions to daily MDA8 ozone concentrations are presented for six example days during the May-August 2014 modeling episode.

10.3.2.1 Episode Maximum Source Sector MDA8 Ozone Contributions by Source Region

Figures 10-21 and 10-22 display the episode maximum MDA8 ozone contributions due to Source Sector emissions from New Mexico. The maximum New Mexico EGU MDA8 ozone contribution is 10.9 ppb and occurs at the location of the Four Corners Power Plan in San Juan County (Figure 10-21a). Elevated ozone due to emissions from New Mexico EGUs is also seen in Lea County at the location of the Hobbs, Cunningham and Maddox EGUs and in southern Doña Ana County at the location of the Rio Grande EGU (Figure 10-21a). The highest New Mexico Non-EGU Point source contribution is 3.1 ppb in eastern Bernalillo County with the Non-EGU Point contribution mostly less than 1 ppb away from Bernalillo County (Figure 10-21b). The maximum New Mexico On-Road (4.7 ppb) and Non-Road (4.0 ppb) ozone contributions both occur in Albuquerque, with a secondary ozone maximum occurring in Las Cruces (Figure 10-21c and d). The On-Road ozone spatial patterns follow the major freeways, including east-west I-40 and north-south I-25, with even I-10 evident in Luna County in southwest New Mexico (Figure 10-21c).

The highest New Mexico O&G Non-Point (7.6 ppb) and O&G Point (5.4 ppb) both occur at the same location in the Permian Basin (Figure 10-22a and b). The O&G Non-Point ozone contributions exceed 5 ppb over large portions of the Permian and San Juan Basins (Figure 10-22a). The O&G Point source ozone contributions are lower, exceeding 3 ppb over large portions of the Permian Basin with much lower ozone contributions in the San Juan Basin (Figure 10-22b). The Other Anthropogenic ozone contribution has a bull's eye centered on Albuquerque with a maximum of 6.2 ppb (Figure 10-22c). Fires are highly episodic with four distinct fire ozone plumes present in New Mexico with episode maximum exceeding 20 ppb (Figure 10-22d).

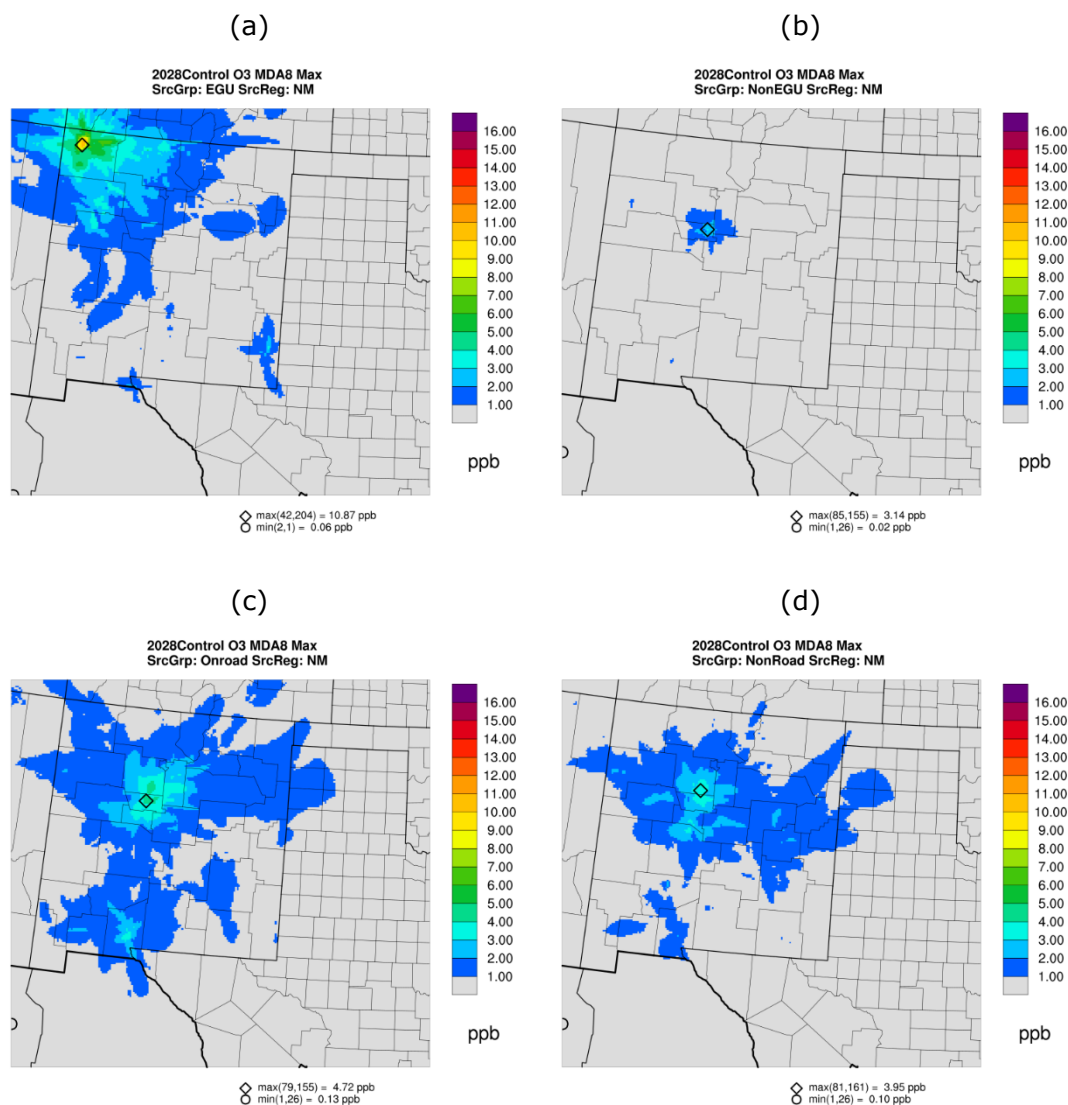


Figure 10-21. Episode maximum daily MDA8 ozone contributions from Source Sectors in New Mexico for: (a) EGU Point; (b) Non-EGU Point; (c) On-Road Mobile; and (d) Non-Road Mobile.

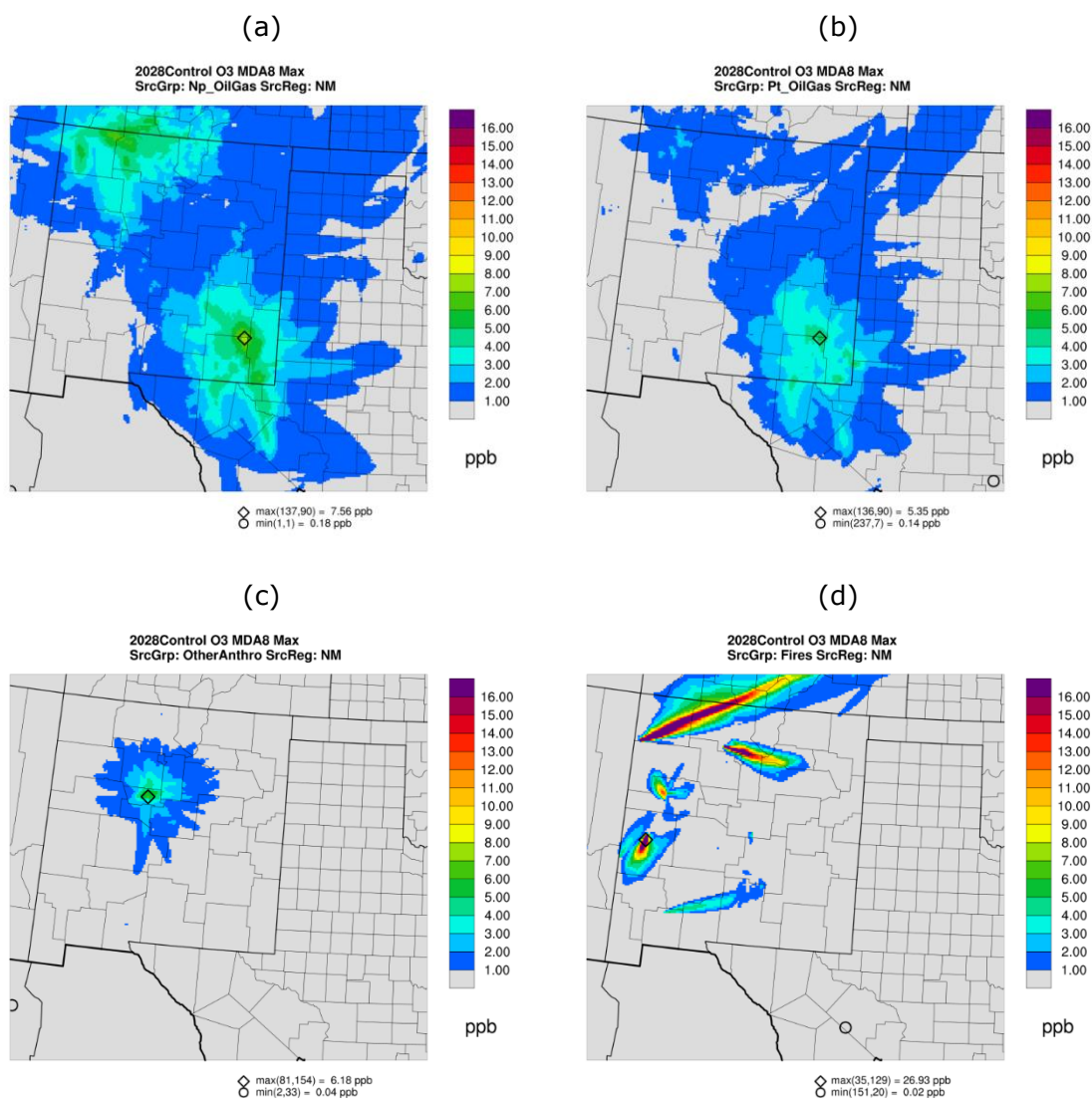


Figure 10-22. Episode maximum daily MDA8 ozone contributions from Source Sectors in New Mexico for: (a) Non-Point O&G; (b) Point O&G; (c) Other Anthropogenic; and (d) Fires.

Figure 10-23 displays the episode maximum MDA8 ozone contributions due to emissions from Texas for 9 Source Sectors (7 anthropogenic Source Sectors plus fires and natural). The presence of EGUs in the Texas Panhandle is clearly evident (e.g., 1,100 MW Tolk coal EGU) that produce ozone in excess of 2 ppb entering eastern New Mexico (Figure 10-23, top left). Elevated ozone due to Texas Non-EGU Point, On-Road, Non-Road, and Other Anthropogenic is seen in El Paso with elevated ozone concentrations entering Doña Ana County. The Texas anthropogenic Source Sector that contributes the most to ozone in New Mexico is O&G. Texas O&G Non-Point (Figure 10-23, middle right) produces ozone above 4 ppb in Lea County and ozone in excess of 2 ppb as far north as Santa Fe and San Miguel Counties. Within the New Mexico portion of the Permian Basin, the maximum Texas O&G Non-Point ozone contribution exceeds 3 ppb and the maximum Texas O&G Point contribution exceeds 2 ppb.

The Colorado Source Sector with the largest contribution to New Mexico ozone concentrations is O&G Non-Point that has a peak ozone contribution in the 4-km domain of 7 ppb that occurs in Colorado just north of the border of San Juan and Rio Arriba Counties (Figure 10-24, middle right). Colorado O&G Non-Point contributes ozone in excess of 4 ppb in the northern portion of the two northwest New Mexico counties and ozone in excess of 1.5-2.0 ppb stretching south to Bernalillo County. Other Colorado anthropogenic emissions Source Sectors contribute ozone in excess of 0.5 ppb across large portions of New Mexico with O&G Point contributing ozone in excess of 1 ppb in San Juan County.

The highest Source Sector ozone contributions in the 4-km New Mexico domain due to all emissions in the U.S. are shown in Figure 10-25. The peak U.S. EGU ozone contribution is 11.5 ppb at the same locations as the New Mexico EGU peak ozone contribution with most of the U.S. EGU contribution at this location due to the FCPP in New Mexico (10.9 ppb, see Figure 10-21a). In addition to the EGU ozone hotspots in the Texas panhandle discussed above (Figure 10-23), there are also all U.S. EGU ozone hotspots in eastern Arizona at the locations of the Springerville and Coronado Generating Stations (Figure 10-25, top left). The U.S. On-Road, Non-Road and Other Anthropogenic ozone contributions (Figure 10-25) look similar to the New Mexico alone ozone contributions (Figures 10-21 and 10-22) with the addition of an incremental ozone concentrations across the 4-km domain due to the U.S. Source Sector emissions from outside New Mexico.

The peak U.S. O&G Non-Point ozone contribution is 10.5 ppb (Figure 10-25, middle right) and occurs at the same location in Colorado on the border with New Mexico as where the Colorado O&G Non-Point peak ozone (7.0 ppb) occurred (Figure 10-24, middle right). The additional 4.5 ppb ozone comes mainly from New Mexico O&G Non-Point emissions (Figure 10-22a). Ozone due to U.S. O&G Non-Point exceeds 8 ppb in the New Mexico portions of the San Juan and Permian Basins. Ozone due to U.S. O&G Point sources exceeds 4 ppb over a wide area in the Permian Basin, whereas U.S. O&G Point rarely exceeds 4 ppb in the San Juan Basin.

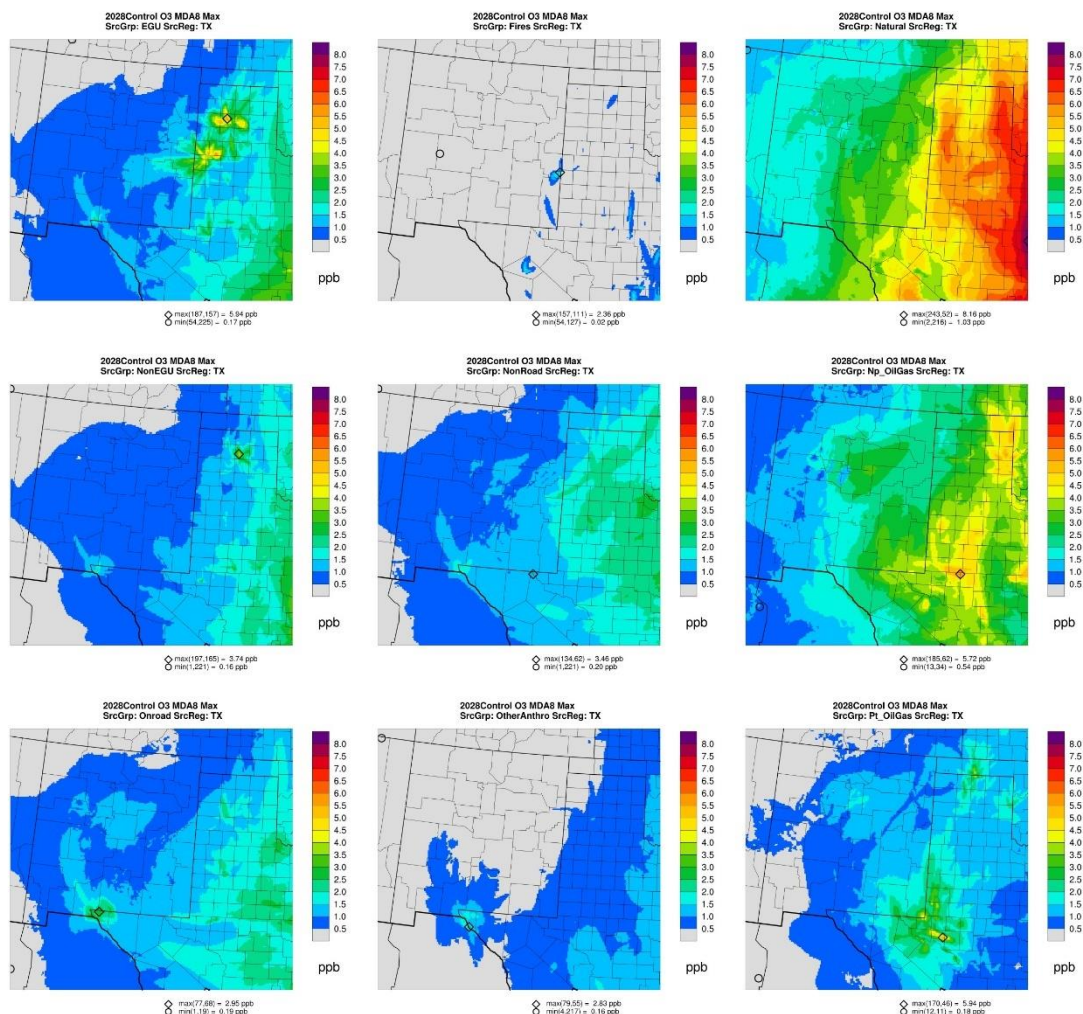


Figure 10-23. Episode maximum MDA8 ozone contributions from Source Sectors in Texas for EGU Point (top left), Fires (top middle), Natural (top right), Non-EGU Point (middle left), Non-Road (middle middle), O&G Non-Point (middle right), On-Road (bottom left), Other Anthropogenic (bottom middle) and O&G Point (bottom right) from the 2028 O&G Control Strategy emissions scenario.

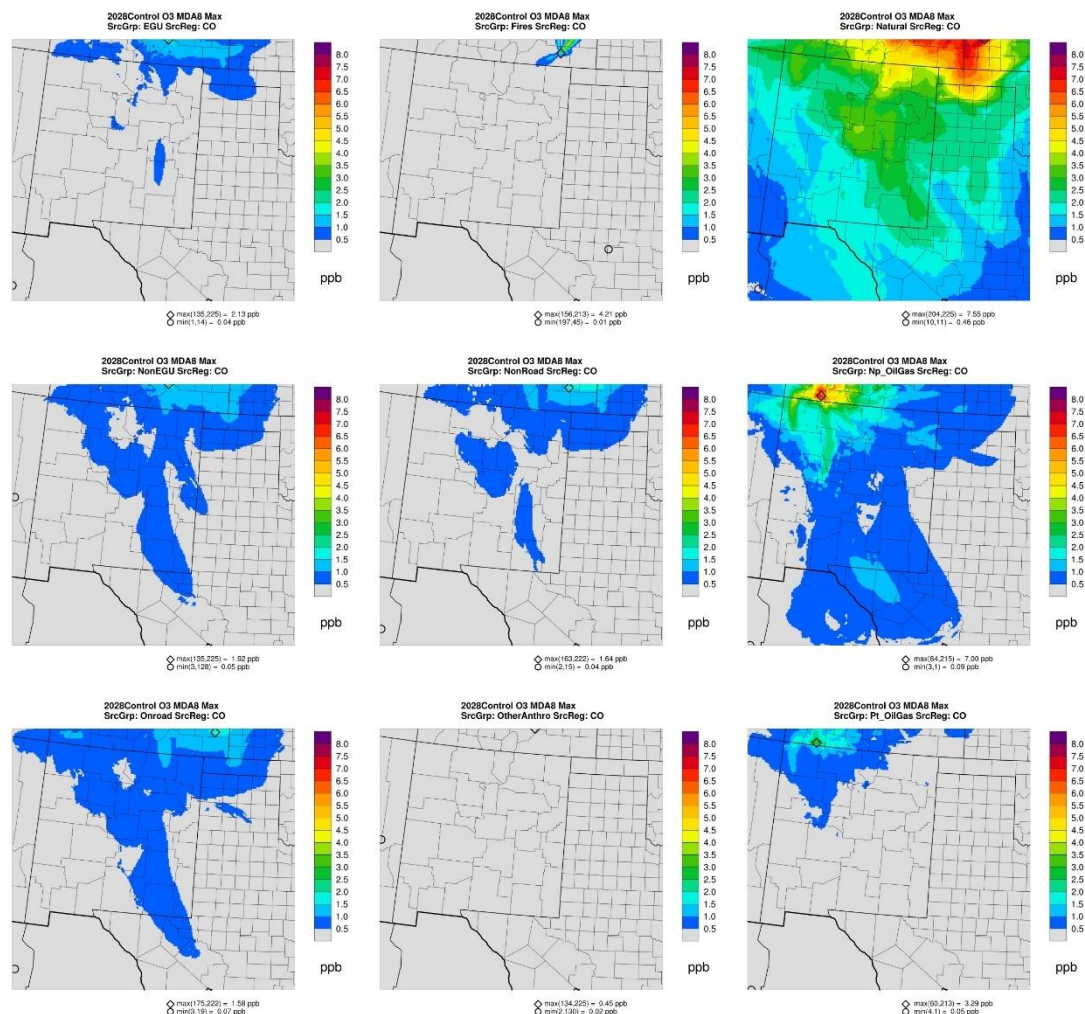


Figure 10-24. Episode maximum MDA8 ozone contributions from Source Sectors in Colorado for EGU Point (top left), Fires (top middle), Natural (top right), Non-EGU Point (middle left), Non-Road (middle middle), O&G Non-Point (middle right), On-Road (bottom left), Other Anthropogenic (bottom middle) and O&G Point (bottom right) from the 2028 O&G Control Strategy emissions scenario.

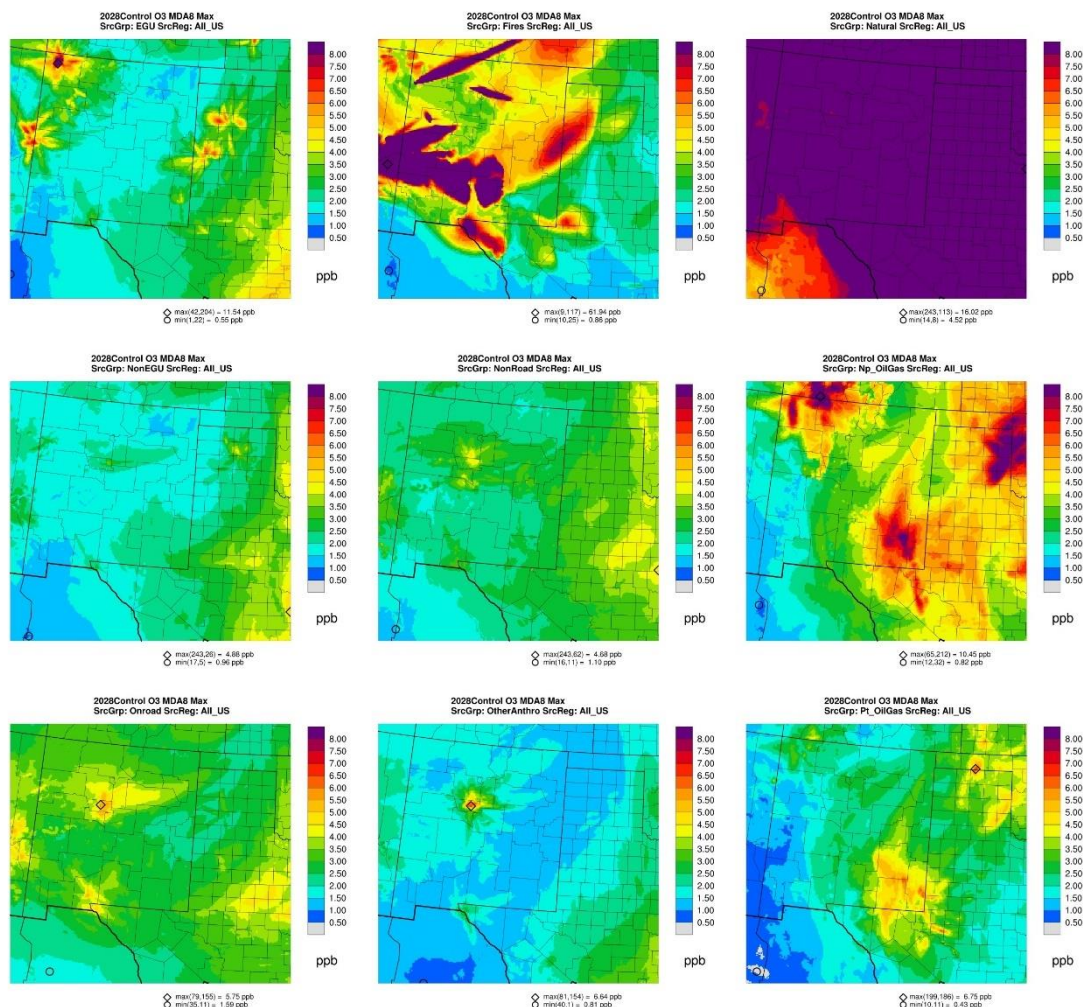


Figure 10-25. Episode maximum MDA8 ozone contributions from Source Sectors in United States for EGU Point (top left), Fires (top middle), Natural (top right), Non-EGU Point (middle left), Non-Road (middle middle), O&G Non-Point (middle right), On-Road (bottom left), Other Anthropogenic (bottom middle) and O&G Point (bottom right) from the 2028 O&G Control Strategy emissions scenario.

The top two panels in Figure 10-26 display the episode maximum MDA8 ozone contributions due to international anthropogenic emissions that are either within the CAMx 36/12/4-km modeling domain (i.e., mainly from in-domain Mexico emissions) or coming through the BCs (BC_{Intl}) from international emissions from outside of the CAMx modeling domains that were generated from 2014 GEOS-Chem simulations. The in-domain international anthropogenic emissions contribute high ozone concentrations in southern New Mexico with values exceeding 16 ppb stretching into Doña Ana, Luna and Otero Counties. The southeastern half of New Mexico has ozone contributions in excess of 8 ppb due to in-domain international emissions. Although the ozone peaks are not as high as the in-domain international anthropogenic emissions, the BC_{Intl} ozone contributions exceed 10 ppb across all of New Mexico and are as high as 13 ppb

(Figure 10-26b). The BC_{Natural} ozone contributions is as high as 49 ppb in San Juan County (Figure 10-26c), while the BC_{US} ozone contributions ranges from 3-4 ppb across New Mexico (Figure 10-26d).

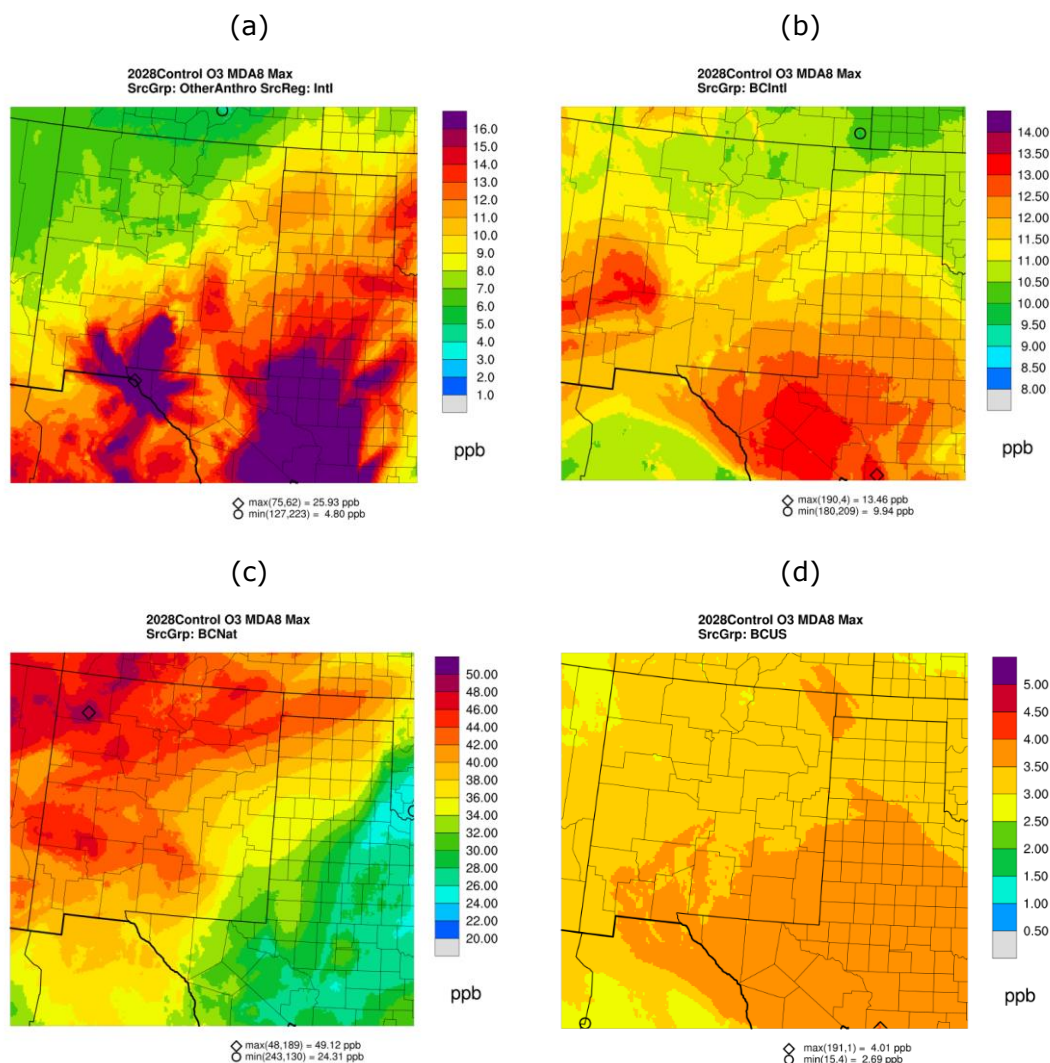


Figure 10-26. Episode maximum MDA8 ozone contributions from: (a) International Anthropogenic Emissions within CAMx 36/12/4-km domains; (b) BCs due to International Anthropogenic Emissions (BC_{Intl}); (c) BCs due to Natural sources (BC_{Natural}); and (d) BCs due to U.S. Anthropogenic Emissions (BC_{US}).

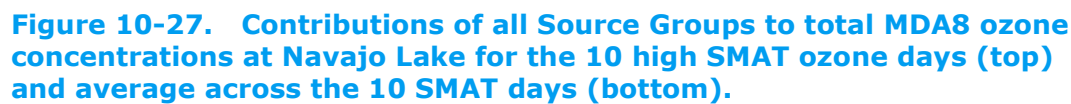
10.3.2.2 Source Sector Ozone Contributions to MDA8 Ozone Concentrations on Modeled High Ozone Days

The daily CAMx 2028 Source Sector APCA ozone source apportionment modeling results were extracted at the locations of the New Mexico ozone monitoring sites and loaded into an Excel Dashboard to visualize the source contributions using stacked bar, pie and tree charts. The Dashboard displays modeled 2028 MDA8 ozone concentrations at a user-selected monitoring site in groups of 10 high ozone days, and the average across the 10 days. These 10 days include the 10 days used in the SMAT 2028 ozone DVF projections, as well as the modeled 2028 first and second highest group of 10 days.

Figures 10-27 through 10-34 display results from the Dashboard for 5 monitoring sites representing different locations in New Mexico. Figures 10-27 and 10-28 display the modeled 2028 ozone results at the Navajo Lake monitor in northwest New Mexico for the 10 SMAT days. The top panel in Figure 10-27 shows stacked bar charts of daily MDA8 ozone contributions by Source Region and BCs for the 10 SMAT days at Navajo Lake. The total MDA8 ozone concentrations are 60-70 ppb and the BCs (grey bar) contribute by far the most with contributions ranging from 26 to 60 ppb. The New Mexico contribution ranges from near zero to 10.9 ppb. The bottom panel in Figure 10-27 shows a Tree Chart and breaks down each Source Region's contribution by Source Category averaged across the 10 SMAT days at Navajo Lake. The Natural category dominates the BC contribution followed by the BC International Anthropogenic Emissions category.

Figure 10-28 focuses on contributions due to emissions from New Mexico Source Categories to MDA8 ozone on the 10 SMAT days at Navajo Lake showing day by day results in the top panel and a pie chart of New Mexico contributions averaged across the 10 days in the bottom panel. For the Navajo Lake site, New Mexico O&G Non-Point is always the largest contributor (38% on average) followed by EGU (29% on average) and then O&G Point (16% on average). Next most important is either On-Road or Natural, depending on the day (6-7% on average). The other two San Juan County sites have higher EGU contributions, with EGU being the highest New Mexico Source Category accounting for 50% and 32% of the New Mexico ozone contribution at, respectively, Substation and Bloomfield.

Figures 10-29 and 10-30 show ozone contribution results for the 10 SMAT days at the Foothills monitoring site and represents typical contributions for sites in Bernalillo County. There is a wide-range of variation in the New Mexico ozone contribution to the 10 SMAT days at Foothills, from near zero to 15 ppb. BCs contribute the most, 27 to 47 ppb. The remaining U.S. and in-domain international emissions also contribute a fair amount. The three most important New Mexico Source Categories contributing to modeled MDA8 ozone at Foothills averaged across the 10 SMAT days are Other Anthropogenic (27%), On-Road (35%) and Non-Road (20%) (Figure 10-30).



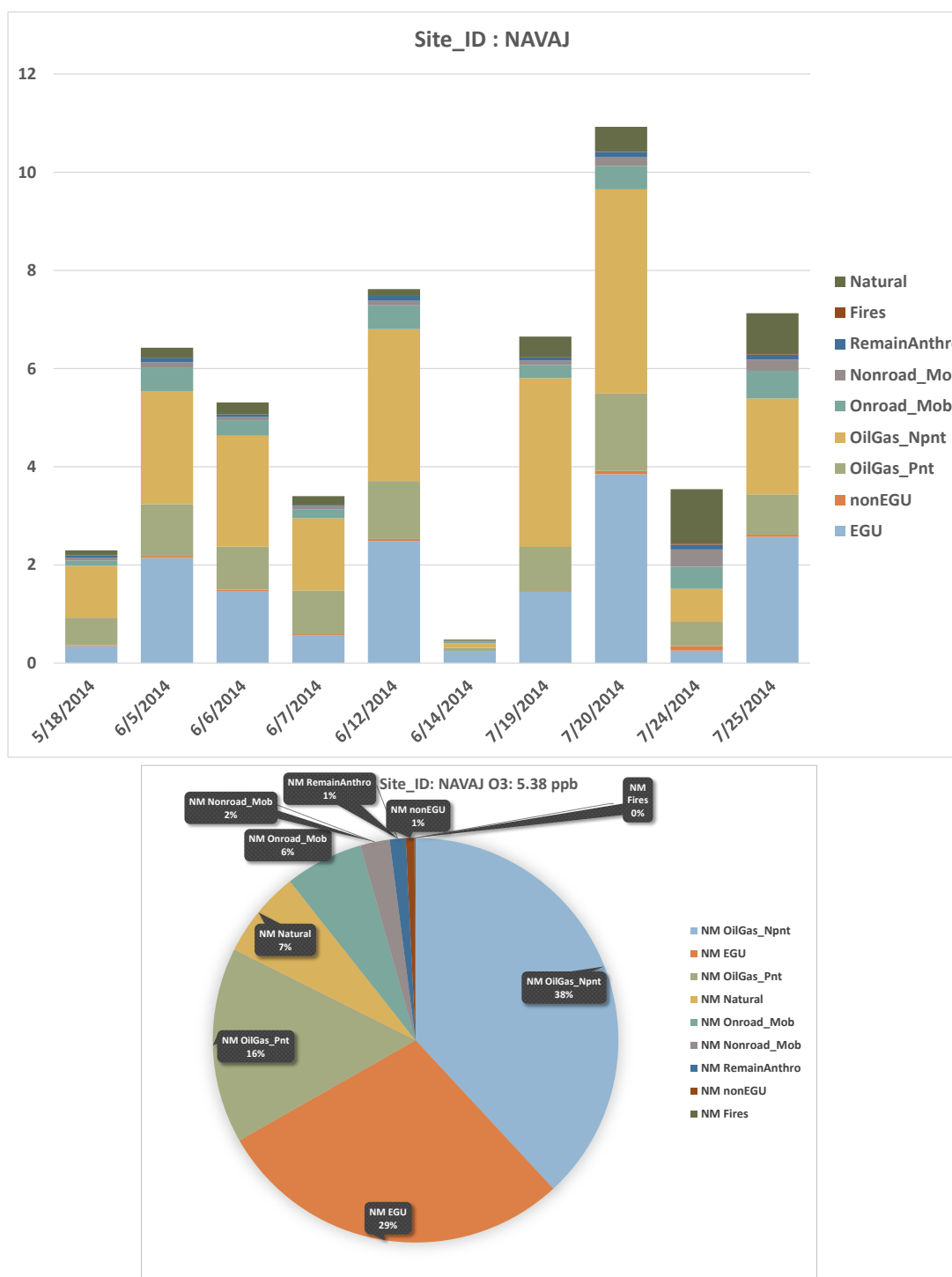


Figure 10-28. Contributions of New Mexico Source Groups to MDA8 ozone concentrations from New Mexico at Navajo Lake for the 10 high SMAT ozone days (top) and average across the 10 SMAT days (bottom).

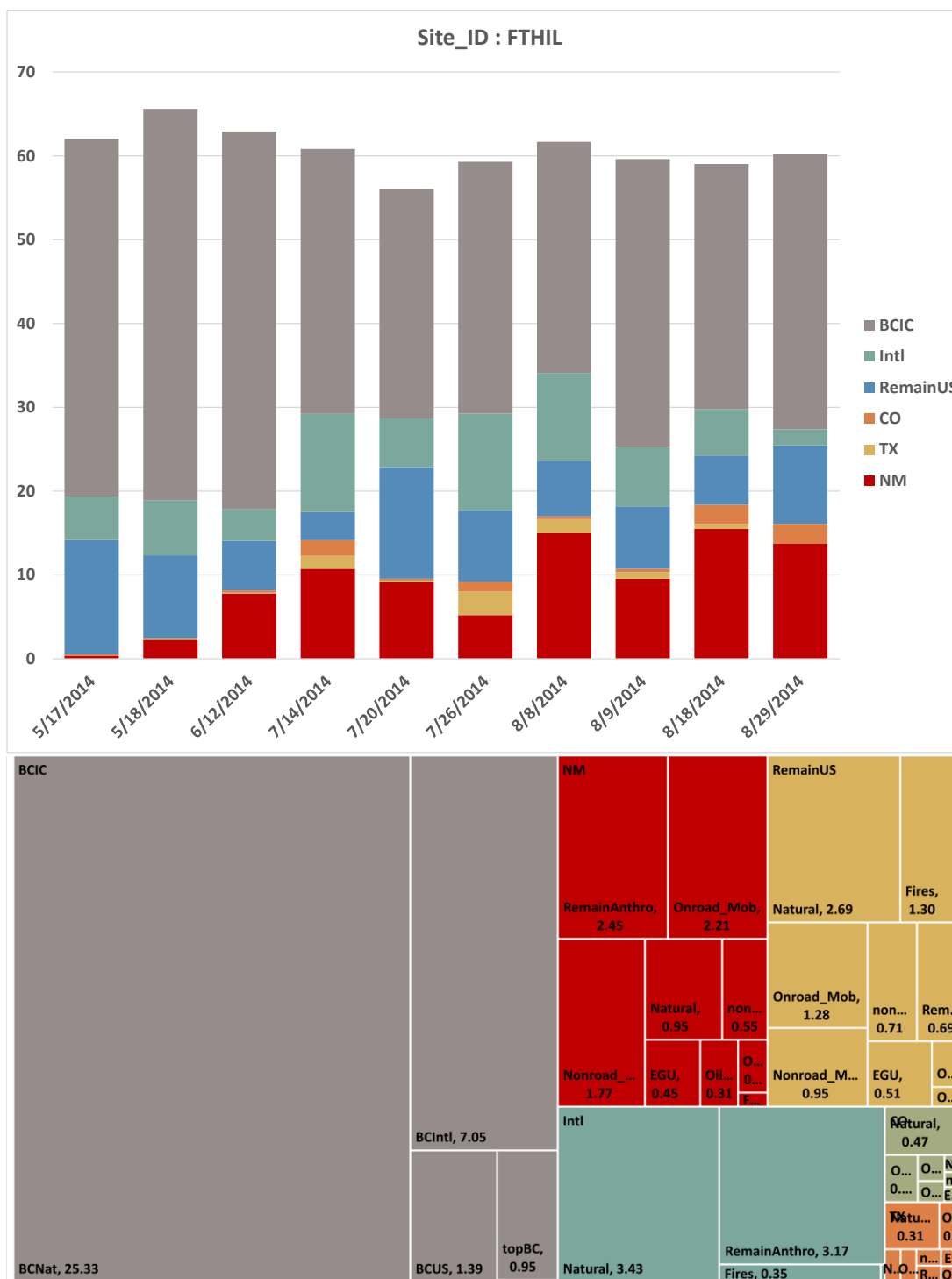


Figure 10-29. Contributions of all Source Groups to total MDA8 ozone concentrations at Foothills for the 10 high SMAT ozone days (top) and average across the 10 SMAT days (bottom).

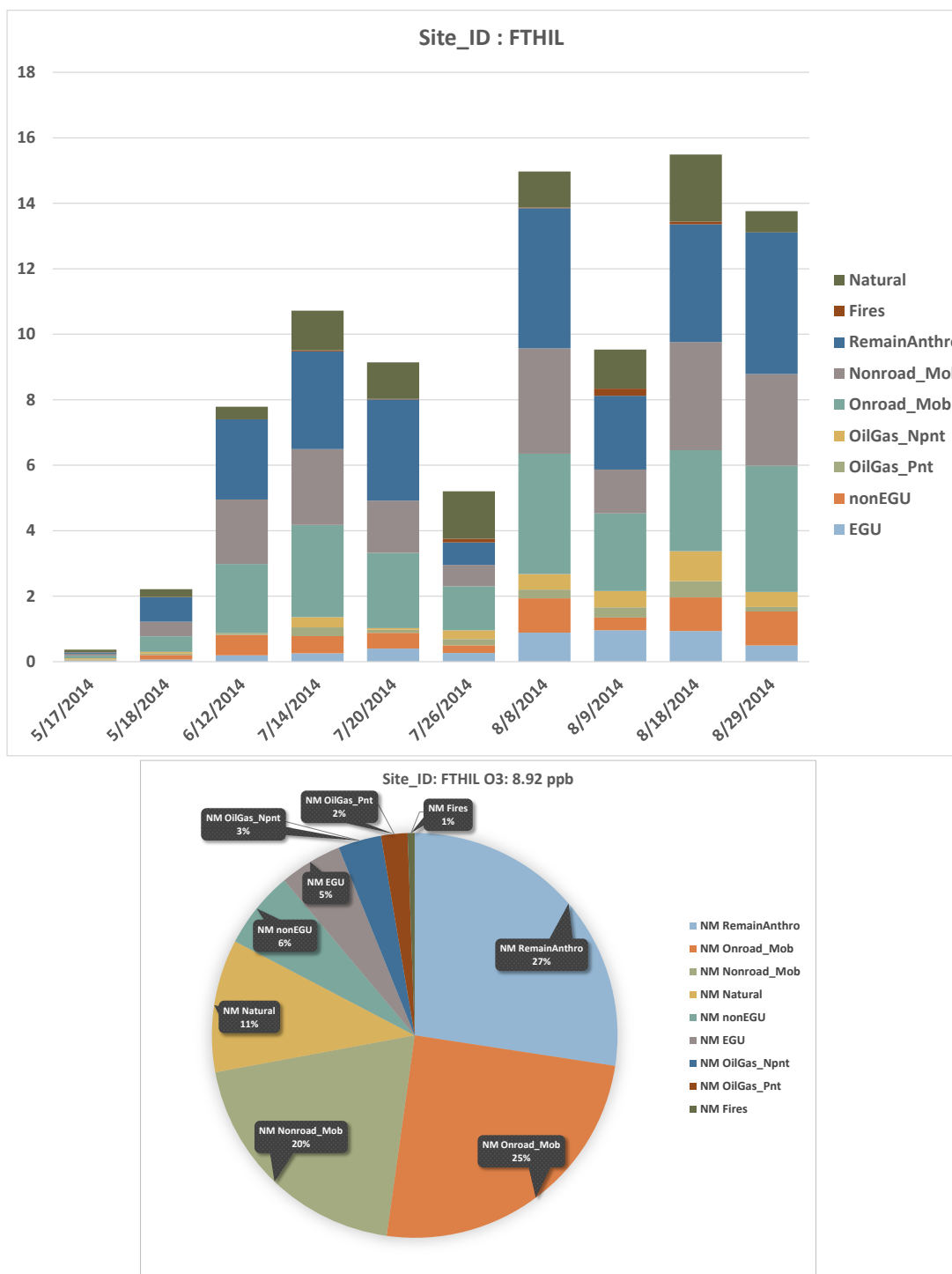


Figure 10-30. Contributions of New Mexico Source Groups to MDA8 ozone concentrations from New Mexico at Foothills for the 10 high SMAT ozone days (top) and average across the 10 SMAT days (bottom).

Ozone contributions for the 10 SMAT days at the Desert View monitor in Doña Ana County are shown in Figures 10-31 and 10-32. BCs from outside the 36-km North American domain is the largest contributor (45% on average), followed by in-domain international emissions (27%), Remainder US (14%) and Texas (8%). Emissions from New Mexico only contribute 4% of the total ozone averaged across the 10 SMAT days at Desert View. International anthropogenic emissions from BCs (5.8 ppb) and in-domain (i.e., Mexico) sources (13.0 ppb) contribute a combined 18.8 ppb (30%) of the average ozone across the 10 SMAT days at Desert View (Figure 10-31, bottom). As shown in Figure 10-32, the contributions from sources in New Mexico contribute from 1.3 to 4.4 ppb to the total MDA8 ozone on the 10 SMAT days, with an average contribution of 2.8 ppb. The largest New Mexico contributing Source Sector is EGU (29%), followed by Natural (18%), On-Road (15%) with 10% contribution coming from Non-Road and Remaining Anthropogenic (Figure 10-32, bottom).

Figures 10-33 and 10-34 displays the 10 SMAT day ozone contributions at the Carlsbad monitoring site. BC and in-domain international emissions contribute the most to ozone at Carlsbad. There is a lot of variation in the day-to-day contributions from New Mexico (0.2 to 5 ppb) with an average contribution of 2.0 ppb. Similar results are seen for Texas (0.5 to 9 ppb with an average of 2.5 ppb). Non-Point O&G and then Point O&G are the two largest anthropogenic Source Sector contributors from both New Mexico and Texas.



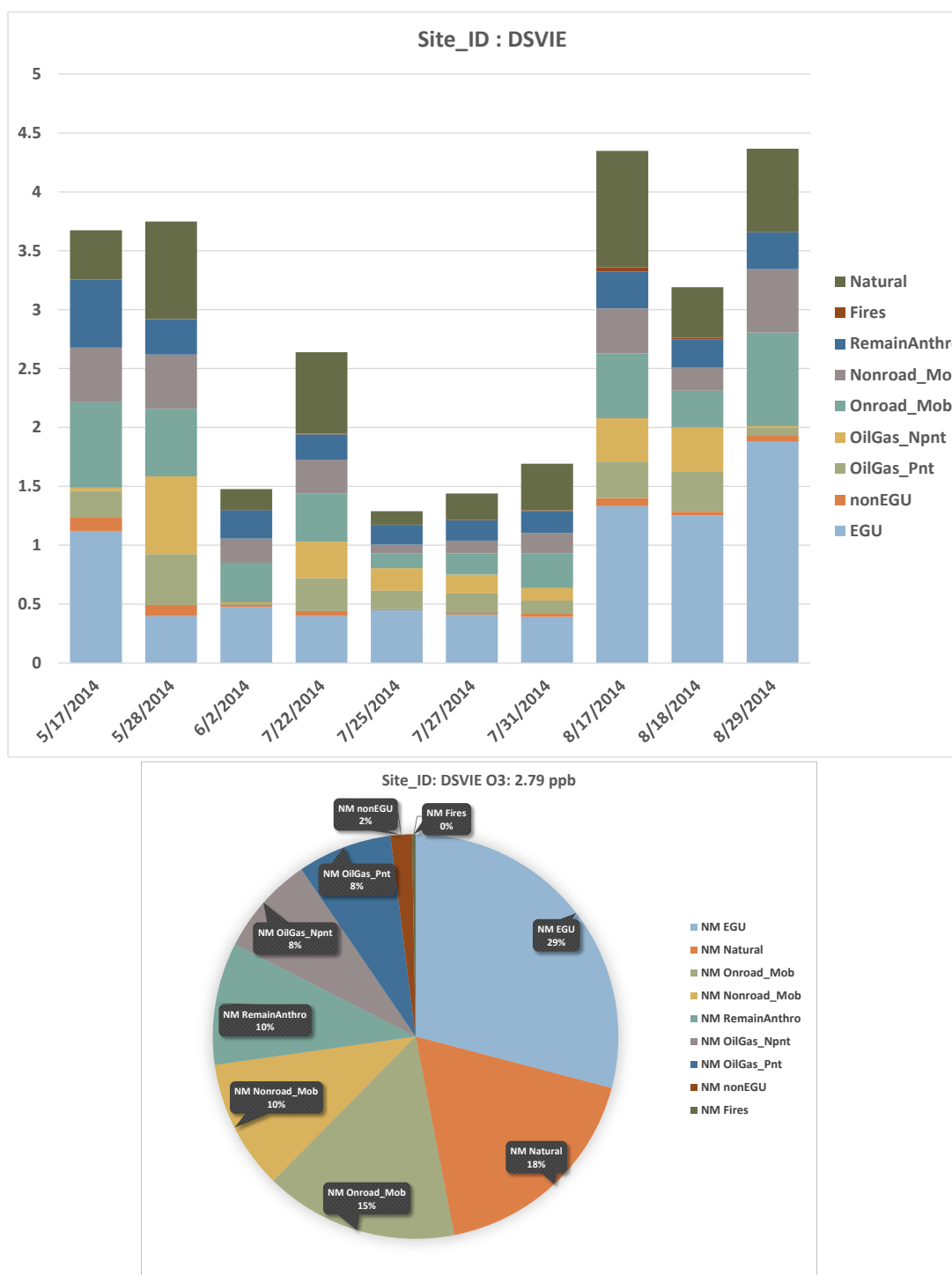


Figure 10-32. Contributions of New Mexico Source Groups to MDA8 ozone concentrations at Desert View for the 10 high SMAT ozone days (top) and average across the 10 SMAT days (bottom).



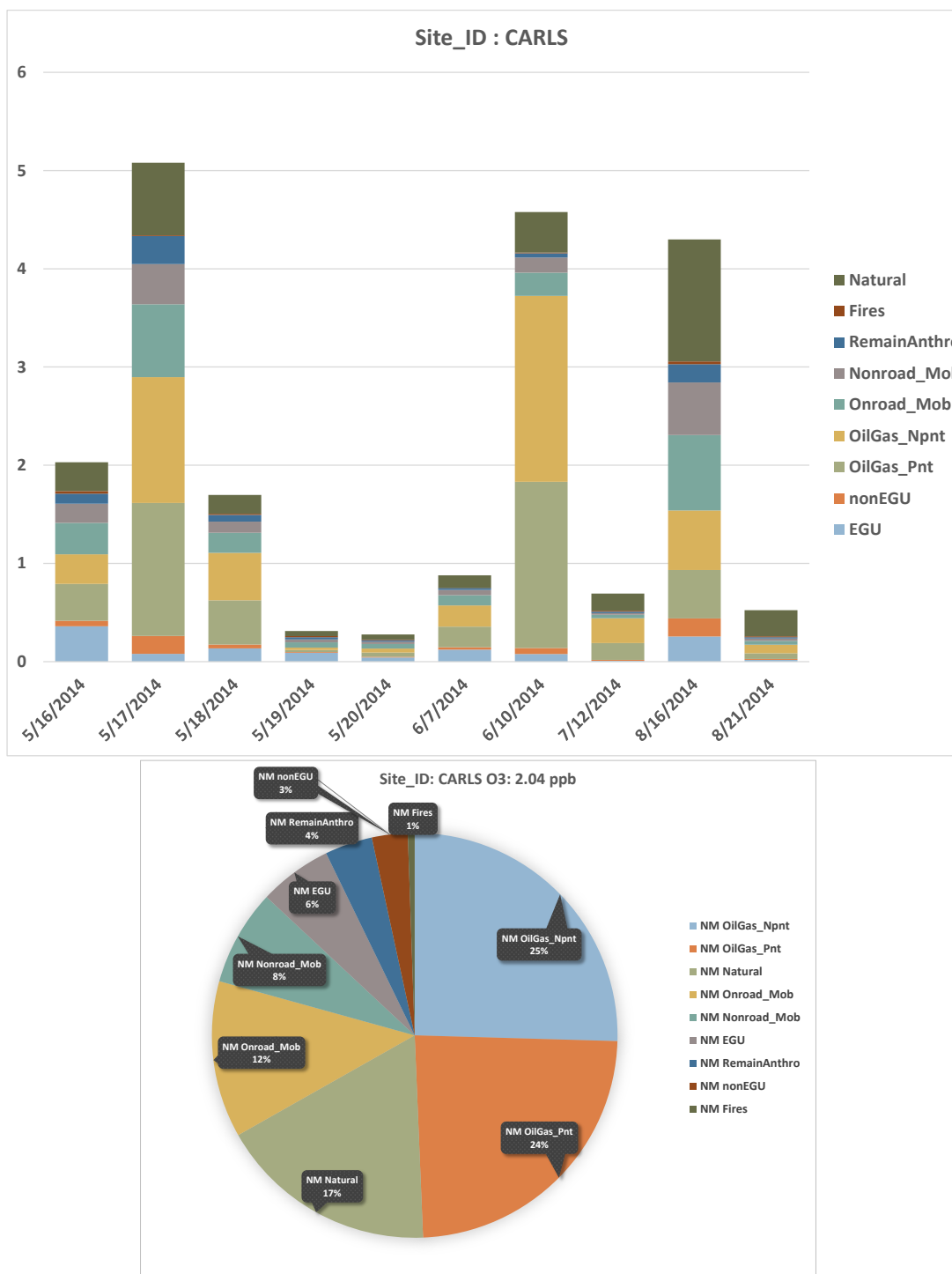


Figure 10-34. Contributions of New Mexico Source Groups to MDA8 ozone concentrations at Carlsbad for the 10 high SMAT ozone days (top) and average across the 10 SMAT days (bottom).

10.3.3 International Anthropogenic Emissions Contributions to Projected 2028 ozone DVFs

The SMAT ozone DVF projection tool was run using the CAMx 2028 O&G Control Strategy output with the contributions of international anthropogenic emissions removed. The ozone concentrations due to the BC_{Intl} and in-domain international emissions (i.e., Mexico, Canada and CMV_{Intl}) were removed from the CAMx 2028 O&G Control Strategy output and SMAT was run to obtain projected 2028 ozone DVFs without any contributions of international anthropogenic emissions. SMAT was run using three different current year ozone design values: $DVC_{2012-2016}$, $DVC_{2015-2019}$ and $DVC_{2017-2019}$ using the same procedures as used in the 2028 ozone DVF projection DVC sensitivity analysis discussed in Chapter 9. Tables 10-4 through 10-6 display the projected 2028 ozone DVFs for the 2028 O&G Control Strategy and 2028 no international anthropogenic emissions scenarios using the three sets of DVCs.

The elimination of the international anthropogenic emissions reduces the projected 2028 ozone DVFs by 13 to 25 ppb with the smallest reductions at the northern and largest reductions at the southern sites in New Mexico. For all DVC scenarios, the projected 2028 ozone DVFs at all monitoring sites in New Mexico are below the 2015 70 ppb ozone NAAQS when ozone contributions due to international anthropogenic emissions are removed. The highest projected 2028 ozone DVF under the no international anthropogenic emissions scenario is 52.8 ppb at the Carlsbad monitoring site when the $DVC_{2017-2019}$ current year design value is used in the 2028 ozone DVF projection.

Figure 10-35 displays the spatial distribution of the current year ozone DVC and the projected 2028 ozone DVF for the 2028 O&G Control Strategy using the SMAT UAA tool and the three definitions of DVCs. Using the $DVC_{2012-2016}$ and $DVC_{2015-2019}$, the SMAT projected 2028 ozone DVFs are all below the 2015 ozone NAAQS under the 2028 O&G Control Strategy emissions scenario. However, when the $DVC_{2017-2019}$ is used, the SMAT UAA estimates projected 2028 ozone DVFs in excess of the 2015 ozone NAAQS across all of Eddy County in southeast New Mexico.

The spatial distribution of the projected 2028 ozone DVF with no international anthropogenic emissions and its differences with the 2028 O&G Control Strategy 2028 ozone DVF using the three DVC definitions are shown in Figure 10-36. The removal of the international anthropogenic emission contributions reduces the 2028 ozone DVFs in New Mexico by 10-30 ppb. The highest 2028 ozone DVF in the 4-km New Mexico domain are 52.5, 55.2 and 56.4 ppb for the, respectively, $DVC_{2012-2016}$, $DVC_{2015-2019}$ and $DVC_{2017-2019}$ current year design value sensitivity scenarios, which are well below the 2015 70 ppb ozone NAAQS.

Table 10-4. Projected 2028 ozone DVFs for the 2028 O&G Control Strategy (2028OGCS) and 2028 no international anthropogenic emissions (2028INTL) scenarios using the DVC₂₀₁₂₋₂₀₁₆ current year ozone DVC.

AQS_ID	2012-16 DVC (ppb)	2028OGCS DVF (ppb)	2028INTL DVF (ppb)	2028 DVF Difference OGCS-INTL (ppb)	Site Name	County
350010023	66.3	60.7	47.2	-13.5	Del Norte HS	Bernalillo
350010024	68.0	62.0	48.5	-13.5	South East Heights	Bernalillo
350010029	66.0	60.5	47.1	-13.4	South Valley	Bernalillo
350010032	67.0	62.1	48.5	-13.6	Westside	Bernalillo
350011012	65.0	58.8	45.7	-13.1	Foothills	Bernalillo
350130008	66.3	59.8	39.9	-19.9	La Union	Doña Ana
350130017	67.0	61.8	38.4	-23.4	Sunland Park	Doña Ana
350130020	67.0	62.2	39.6	-22.6	Chaparral	Doña Ana
350130021	72.0	66.8	42.6	-24.2	Desert View	Doña Ana
350130022	71.3	66.0	42.2	-23.8	Santa Teresa	Doña Ana
350130023	65.0	60.2	41.5	-18.7	Solano	Doña Ana
350151005	69.0	66.4	46.1	-20.3	Carlsbad	Eddy
350171003	62.0	58.9	43.0	-15.9	Chino Copper Smelt	Grant
350250008	66.0	63.3	44.9	-18.4	Hobbs Jefferson	Lea
350290003	66.0	62.5	43.3	-19.2	Deming Airport	Luna
350390026	64.0	60.0	47.4	-12.6	Coyote Ranger Dist	Rio Arriba
350431001	64.0	58.1	44.4	-13.7	Bernalillo (E Avenida)	Sandoval
350450009	64.3	60.2	46.4	-13.8	Bloomfield	San Juan
350450018	67.0	63.3	50.2	-13.1	Navajo Lake	San Juan
350451005	63.7	59.6	48.5	-11.1	Substation	San Juan
350490021	64.3	60.4	47.9	-12.5	Santa Fe Airport	Santa Fe
350610008	66.3	62.0	47.5	-14.5	Los Lunas (Los Lentos)	Valencia

Table 10-5. Projected 2028 ozone DVFs for the 2028 O&G Control Strategy (2028OGCS) and 2028 no international anthropogenic emissions (2028INTL) scenarios using the DVC₂₀₁₅₋₂₀₁₉ current year ozone DVC.

AQS_ID	2015-19 DVC (ppb)	2028OGCS DVF (ppb)	2028INTL DVF (ppb)	2028 DVF Difference OGCS–INTL (ppb)	Site Name	County
350010023	69.0	63.1	49.2	-13.9	Del Norte HS	Bernalillo
350010029	66.0	60.5	47.1	-13.4	South Valley	Bernalillo
350011012	69.0	62.4	48.5	-13.9	Foothills	Bernalillo
350130008	68.7	62.0	41.3	-20.7	La Union	Doña Ana
350130020	70.7	65.7	41.8	-23.9	Chaparral	Doña Ana
350130021	74.3	68.9	43.9	-25.0	Desert View	Doña Ana
350130022	74.0	68.5	43.8	-24.7	Santa Teresa	Doña Ana
350130023	67.7	62.7	43.3	-19.4	Solano	Doña Ana
350151005	73.7	70.9	49.2	-21.7	Carlsbad	Eddy
350153001	71.0	69.3	44.1	-25.2	Carlsbad NP	Eddy
350250008	69.3	66.5	47.1	-19.4	Hobbs Jefferson	Lea
350390026	66.3	62.2	49.1	-13.1	Coyote Ranger Dist	Rio Arriba
350431001	67.0	60.9	46.5	-14.4	Bernalillo (E Avenida)	Sandoval
350450009	67.0	62.8	48.3	-14.5	Bloomfield	San Juan
350450018	69.0	65.2	51.7	-13.5	Navajo Lake	San Juan
350451005	67.3	62.9	51.2	-11.7	Substation	San Juan
350490021	65.0	61.0	48.4	-12.6	Santa Fe Airport	Santa Fe
350610008	66.7	62.3	47.8	-14.5	Los Lunas (Los Lentos)	Valencia

Table 10-6. Projected 2028 ozone DVFs for the 2028 O&G Control Strategy (2028OGCS) and 2028 no international anthropogenic emissions (2028INTL) scenarios using the DVC₂₀₁₇₋₂₀₁₉ current year ozone DVC.

AQS_ID	2017-19 DVC (ppb)	2028OGCS DVF (ppb)	2028INTL DVF (ppb)	2028 DVF Difference OGCS-INTL (ppb)	Site Name	County
350010023	70.0	64.0	49.9	-14.1	Del Norte HS	Bernalillo
350010029	67.0	61.4	47.8	-13.6	South Valley	Bernalillo
350011012	71.0	64.2	49.9	-14.3	Foothills	Bernalillo
350130008	70.0	63.2	42.1	-21.1	La Union	Doña Ana
350130020	73.0	67.8	43.1	-24.7	Chaparral	Doña Ana
350130021	77.0	71.4	45.5	-25.9	Desert View	Doña Ana
350130022	76.0	70.3	45.0	-25.3	Santa Teresa	Doña Ana
350130023	70.0	64.8	44.7	-20.1	Solano	Doña Ana
350151005	79.0	76.0	52.8	-23.2	Carlsbad	Eddy
350250008	71.0	68.1	48.3	-19.8	Hobbs Jefferson	Lea
350390026	67.0	62.8	49.6	-13.2	Coyote Ranger Dist	Rio Arriba
350431001	68.0	61.8	47.2	-14.6	Bernalillo (E Avenida)	Sandoval
350450009	68.0	63.7	49.1	-14.6	Bloomfield	San Juan
350450018	69.0	65.2	51.7	-13.5	Navajo Lake	San Juan
350451005	69.0	64.5	52.5	-12.0	Substation	San Juan
350490021	66.0	62.0	49.1	-12.9	Santa Fe Airport	Santa Fe
350610008	68.0	63.5	48.7	-14.8	Los Lunas (Los Lentos)	Valencia

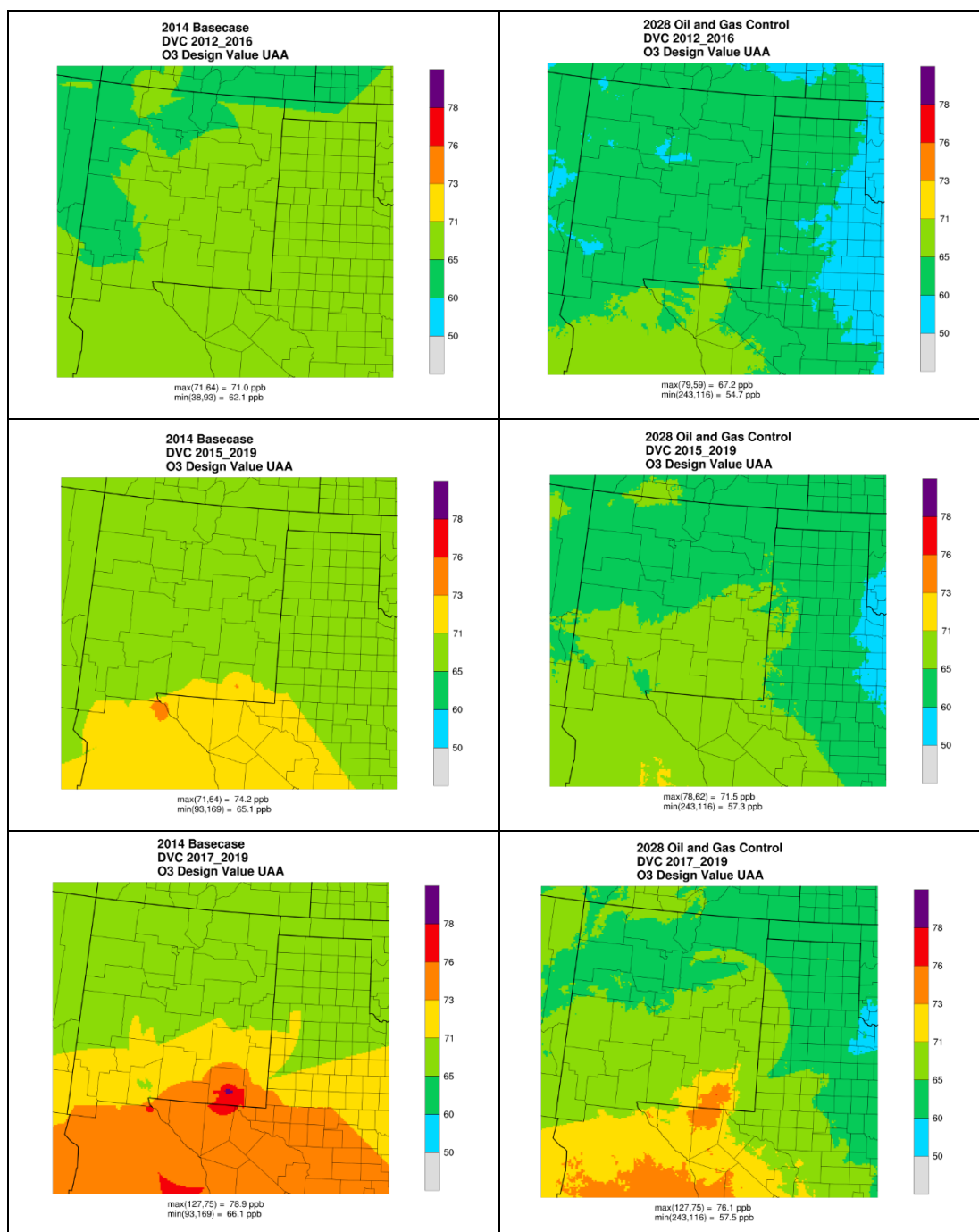


Figure 10-35. SMAT UAA ozone design values (ppb) for the current year ozone DVC (left) and projected 2028 ozone DVC for the 2028 O&G Control Strategy (right) using current year DVCs based on 2012-2016 (top), 2015-2019 (middle) and 2017-2019 (bottom) ozone design values.

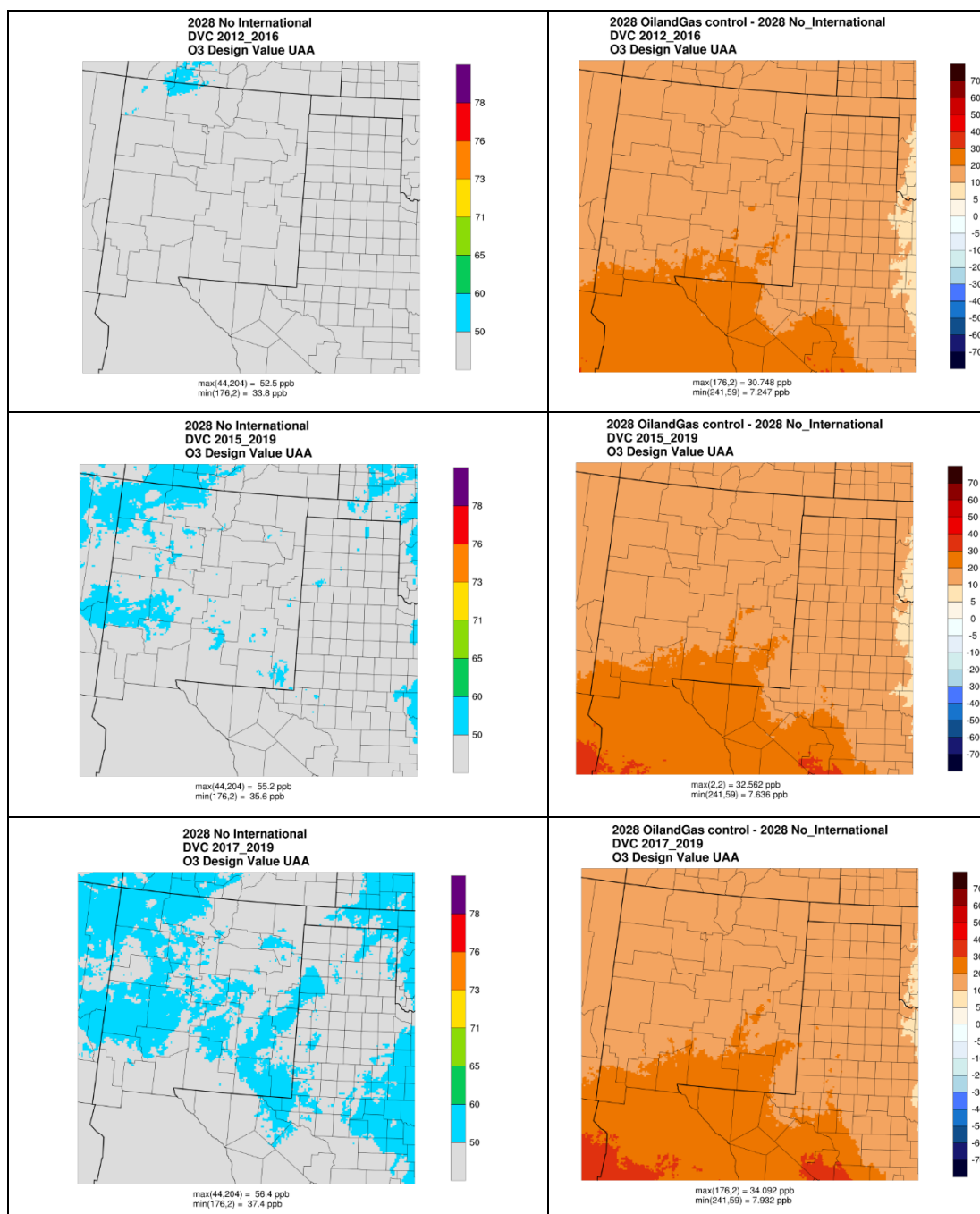


Figure 10-36. SMAT UAA ozone design values (ppb) for the projected 2028 ozone DVF from the 2028 No International Anthropogenic Emissions scenario (left) and differences in 2028 ozone DVFs between the 2028 No International Emissions and 2028 O&G Control Strategy scenarios (right) using current year DVCs based on 2012-2016 (top), 2015-2019 (middle) and 2017-2019 (bottom) ozone design values.

11. 2028 VOC AND NO_x SENSITIVITY OSAT OZONE SOURCE APPORTIONMENT MODELING

A second CAMx 2028 ozone source apportionment model simulation was performed to estimate whether ozone formation that leads to elevated ozone concentrations in New Mexico occurs under conditions that are more sensitive to VOC or NO_x emissions. The VOC/NO_x emissions sensitivity ozone source apportionment simulation used the Ozone Source Apportionment Technology (OSAT) version of the CAMx ozone source apportionment tools. As discussed in Section 10.1, when using OSAT, the relative amounts of the O3V and O3N ozone source apportionment tracers provide an indication of whether ozone formation is more sensitive to VOC or NO_x emissions.

11.1 2028 OSAT Ozone Source Apportionment Design

The CAMx 2028 OSAT VOC/ NO_x sensitivity ozone source apportionment simulation used the 36/12/4-km nested domain structure, summer of 2014 meteorology and the 2028 O&G Control Strategy emissions scenario. The same five Source Regions as used in the 2028 Source Sector APCA ozone source apportionment simulation were used (See Figure 10-1):

1. New Mexico;
2. Texas;
3. Colorado;
4. Remainder U.S. states plus coastal water out to 200 nautical miles (nmi) of the U.S. coast; and
5. International, which include Mexico, Canada and waters off their coasts, plus waters more than 200 nmi off the U.S. coast.

Three Source Categories were specified in the 2028 OSAT ozone source apportionment modeling:

1. Anthropogenic emissions;
2. Fires; and
3. Natural emissions.

Fires include U.S. wildfires (WF), wildland prescribed burns (Rx) and agricultural burning (Ag), and other fires from Mexico and Canada. Natural emissions include biogenic, lightning NO_x (LNO_x), windblown dust (WBD) and oceanic (sea salt and DMS) sources.

With 5 Source Regions and 3 Source Categories, plus separate Source Groups for Initial Concentrations (IC) and Boundary Conditions (BC), that results in a total of 17 Source Groups for which separate ozone source contributions will be obtained in the 2028 OSAT ozone source apportionment modeling ($17 = 5 \times 3 + 2$).

11.2 Spatial Distribution of VOC/NO_x Ozone Formation Sensitivity

The sensitivity of ozone formation to VOC and NO_x emissions is obtained for each of the 15 emission Source Groups that consist of emissions from 3 source categories (i.e., anthropogenic, fires and natural) emitting from 5 Source Regions. The percent contribution of NO_x sensitive ozone formation metric is used to display the ozone formation sensitivity that is defined as follows:

$$\text{Percent NO}_x \text{ Sensitive Ozone (\%NO}_x\text{Sens)} = 100 \times \sum \text{O3N}_i / \sum (\text{O3V}_i + \text{O3N}_i)$$

Where the sum is performed over the 15 different emissions Source Groups (i) that consist of the three emission Source Categories emitting from the 5 Source Regions. The Percent VOC Sensitive Ozone will be 100 minus the Percent NO_x Sensitive Ozone metric.

Note that the O3V and O3N tracers for the IC and BC Source Groups are not used in the Percent NO_x Sensitive Ozone metric since they were defined from the 2014 simulation of the 2014 GEOS-Chem global chemistry model and the CAMx GEOS2CAMx processor arbitrarily assigns half of the GEOS-Chem total ozone to the O3V and O3N tracers each so do they not have accurate information on whether such IC/BC ozone concentrations are more VOC or NO_x sensitive.

Spatial displays of the Percent NO_x Sensitive Ozone metric were generated for Maximum Daily Average 8-hour (MDA8) ozone concentrations and several combinations of Source Groups for each day of the May-August 2014 modeling episode. When presenting the Percent NO_x Sensitive Ozone metric for a combination of Source Groups, it is also important to know the total MDA8 ozone due to the same combination of Source Groups in order to interpret the significance of the %NO_xSens metric; if the MDA8 ozone concentrations due to the combination of Source Groups is very small (e.g., < 0.01 ppb), whether the ozone formed was more sensitive to VOC or NO_x emissions is inconsequential. Spatial maps across the New Mexico 4-km modeling domains were generated for total MDA8 ozone and Percent NO_x Sensitive Ozone for the following combinations of Source Groups:

- All emissions based Source Groups (i.e., anthropogenic, fires and natural emissions emitted from the 5 Source Regions in the CAMx modeling domain).
- All anthropogenic emissions based Source Groups across the CAMx modeling domain.
- The New Mexico anthropogenic emissions Source Group.

The Percent NO_x Sensitive Ozone for the New Mexico anthropogenic emissions Source Group provides information on whether New Mexico VOC or NO_x emissions may be more important to ozone formation.

Figures 11-1 through 11-8 display the total MDA8 ozone and Percent NO_x Sensitive ozone metric for eight example days during the episode that tended to have relatively higher ozone concentrations and included the six example days displayed in previous Chapters.

11.2.1 Percent NO_x Sensitive Ozone on May 17, 2014

Figure 11-1 displays the 2028 OSAT source apportionment results for the May 17, 2014 day that was dominated by ozone concentrations from a fire in eastern Arizona that caused modeled elevated ozone concentrations in southwestern New Mexico. Figure 11-1a displays the MDA8 ozone concentrations from all Source Groups, including IC/BC, and is the modeled total MDA8 ozone on this day. The modeled peak MDA8 ozone on May 17th is 129 ppb and occurs within the fire ozone plume in eastern Arizona. The Percent NO_x Sensitive Ozone due to all emissions based source groups indicates ozone formation across the 4-km NM domain is more NO_x sensitive than VOC sensitive with the color scale going from green (%NO_xSens > 65%) to red/orange (%NO_xSens > 85%) (Figure 11-1b). Although, it is interesting to note that at the locations of the higher total MDA8 ozone concentrations, the amount of %NO_xSens ozone is less, with the lowest value (%NO_xSens = 64%) occurring at the same location as the peak modeled MDA8 ozone concentration in eastern Arizona.

Figure 11-1c and d show the MDA8 ozone and %NO_xSens metric for all anthropogenic emissions on May 17th, with the anthropogenic emissions %NO_xSens metric being mostly orange and red (%NO_xSens > 90%), indicating mostly NO_x sensitive ozone formation. There are areas of high MDA8 ozone due to anthropogenic emissions in west Texas (peak of 23 ppb) where %NO_xSens ozone is a little lower (80-90%), as well as a small area on the Colorado side of the San Juan Basin with lower %NO_xSens metric. Figure 11-1e and f show the MDA8 ozone and %NO_xSens metric for New Mexico anthropogenic emissions on May 17th. The highest contribution of New Mexico anthropogenic emissions to MDA8 ozone is 9 ppb and occurs in the Permian Basin with ozone formation being very NO_x sensitive (%NO_xSens > 85%). The lowest New Mexico NO_x sensitive ozone is in the San Juan Basin with a minimum value of 32%, indicating a VOC sensitive ozone formation value of 68% (Figure 11-1f). The New Mexico anthropogenic emissions ozone contribution in the San Juan Basin is less than 3 ppb (Figure 11-1e).

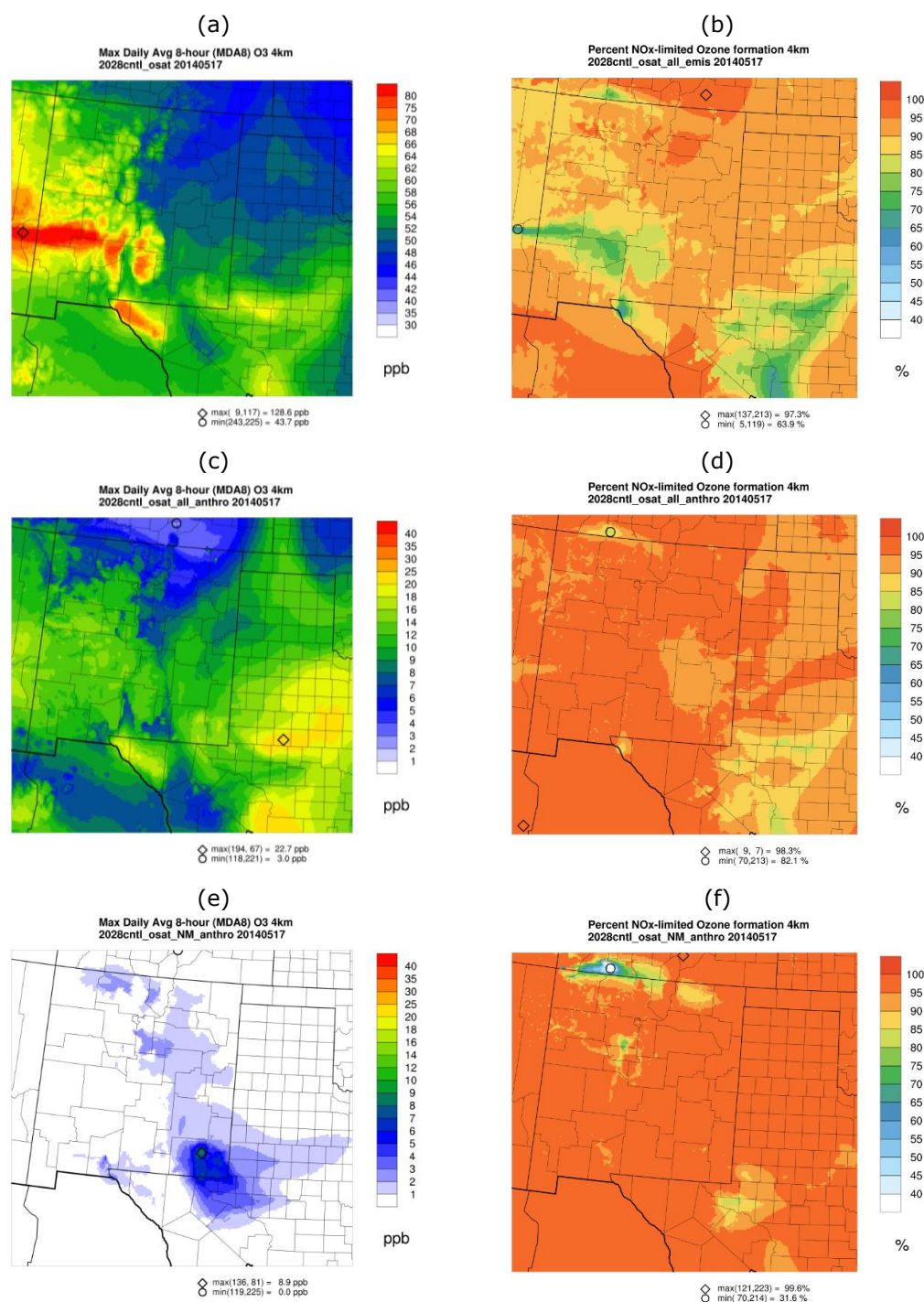


Figure 11-1. 2028 MDA8 ozone (left) and Percent NO_x Sensitive Ozone (right) on May 17, 2014 for: (a) total MDA8 ozone; (c) ozone due to anthropogenic emissions; (e) ozone due to New Mexico anthropogenic emissions; (b) %NO_xSens for all emissions; (d) %NO_xSens for all anthropogenic emissions; and (f) %NO_xSens for New Mexico anthropogenic emissions.

11.2.2 Percent NO_x Sensitive Ozone on May 26, 2014

On May 26th, the peak modeled MDA8 ozone concentrations is 58 ppb and occurs in San Juan County (Figure 11-2a). Ozone formation from all emissions is mostly NO_x sensitive across New Mexico (Figure 11-2b). Although the lowest %NO_xSens due to all emissions on May 26 (68%) occurs at the location of the peak MDA8 ozone in San Juan County. When looking at just anthropogenic emissions, the %NO_xSens ozone is mostly greater than 90% across most of New Mexico on May 26th with the exception of San Juan County and stretching south into McKinley County with a %NO_xSens minimum of 69% (Figure 11-2d) occurring at the same location as the modeled 58 ppb peak. The maximum MDA8 ozone due to New Mexico anthropogenic emissions on May 26th is 7 ppb and occurs at the same location as the 58 ppb total MDA8 ozone peak in San Juan County. Ozone formation due to New Mexico emissions at the location of this MDA8 ozone peak in San Juan County is split approximately equally between VOC and NO_x sensitive ozone formation (%NO_xSens = 45%; Figure 11-2f).

11.2.3 Percent NO_x Sensitive Ozone on May 28, 2014

May 28th has elevated ozone concentrations in southern New Mexico, including southern Doña Ana County and the Permian Basin, as well as within the Albuquerque urban plume (Figure 11-3a). Ozone formation across New Mexico due to anthropogenic emission tends to be mostly NO_x sensitive on May 28th with the lowest NO_x sensitive ozone of 73% occurring at almost the exact same location in southern Doña Ana County as the ozone peak (Figure 11-3b). When just looking at the sensitivity of anthropogenic emissions, the %NO_xSens value at the location of the peak in southern Doña Ana County increases from 73% to 81% (Figure 11-3d). Finally, the contributions of New Mexico anthropogenic emissions to the ozone peak in southern Doña Ana County is 2-4 ppb and is very NO_x sensitive (%NO_xSens > 90%) (Figure 11-3e and f). The highest MDA8 ozone due to New Mexico anthropogenic emissions on May 28th is 9 ppb in the Albuquerque urban plume where %NO_xSens is slightly lower than the surrounding areas (85-90%), with the lowest New Mexico anthropogenic emissions %NO_xSens being 75% in a high ozone area in the Permian Basin.

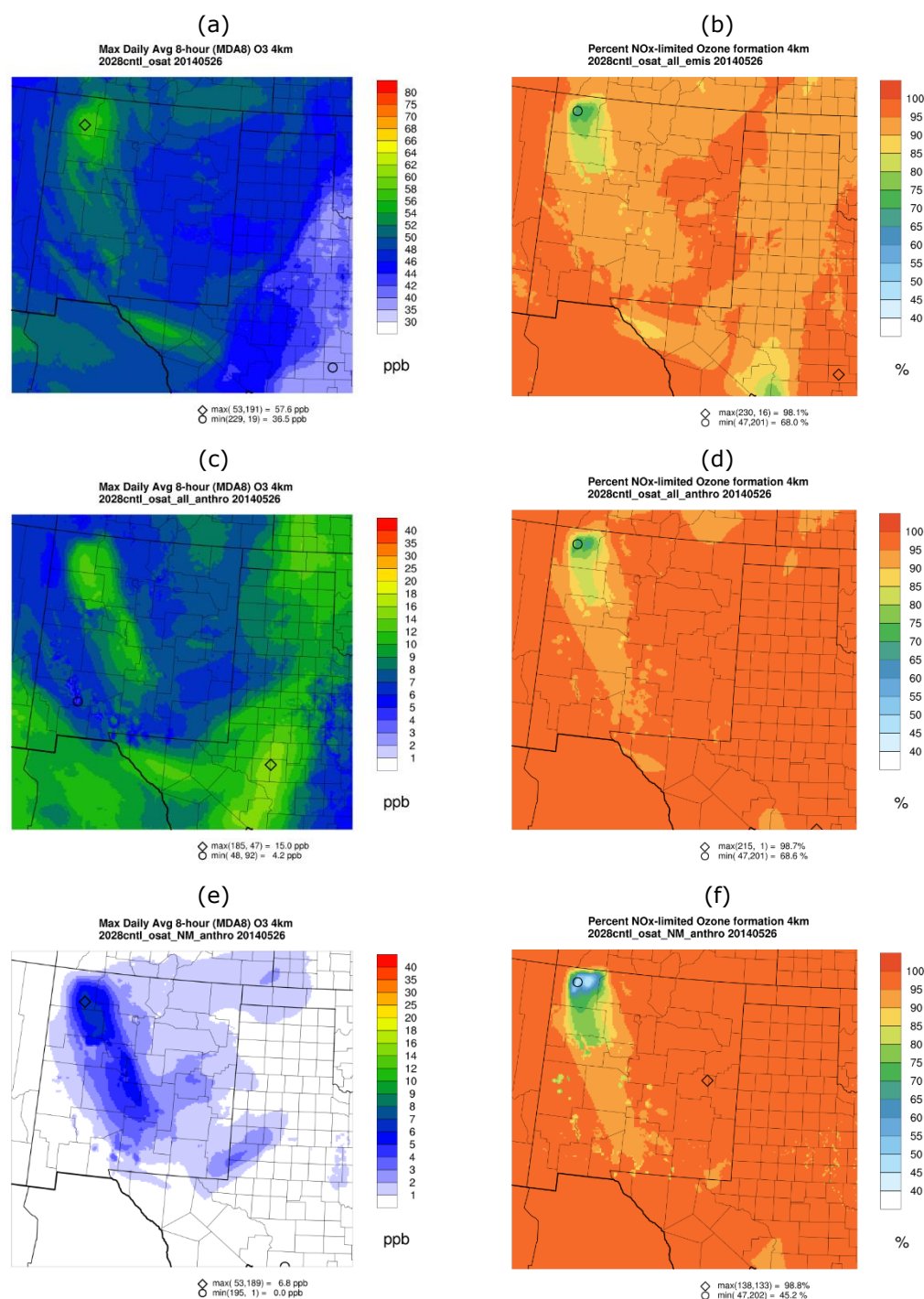


Figure 11-2. 2028 MDA8 ozone (left) and Percent NO_x Sensitive Ozone (right) on May 26, 2014 for: (a) total MDA8 ozone; (c) ozone due to anthropogenic emissions; (e) ozone due to New Mexico anthropogenic emissions; (b) %NO_xSens for all emissions; (d) %NO_xSens for all anthropogenic emissions; and (f) %NO_xSens for New Mexico anthropogenic emissions.

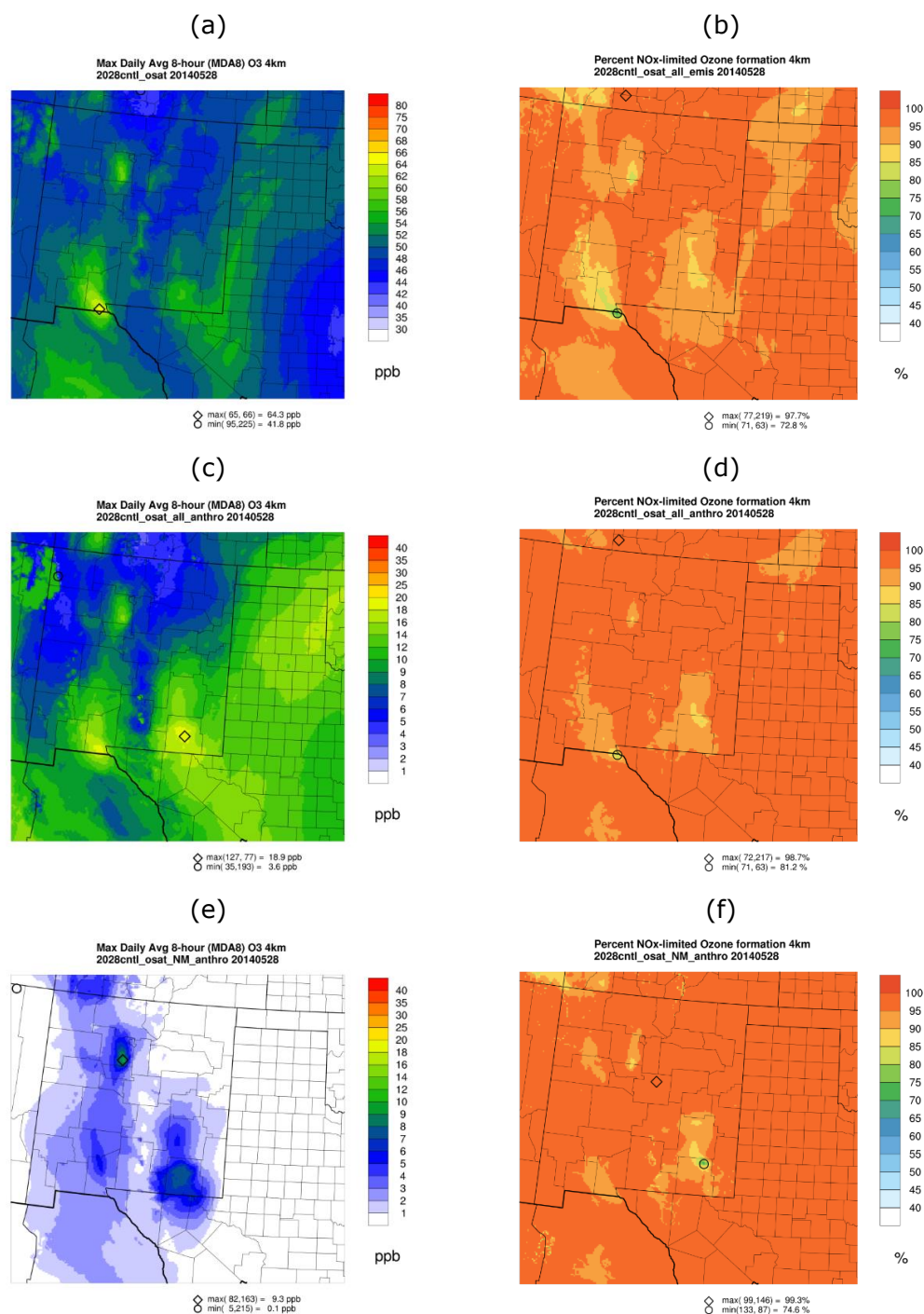


Figure 11-3. 2028 MDA8 ozone (left) and Percent NO_x Sensitive Ozone (right) on May 28, 2014 for: (a) total MDA8 ozone; (c) ozone due to anthropogenic emissions; (e) ozone due to New Mexico anthropogenic emissions; (b) %NO_xSens for all emissions; (d) %NO_xSens for all anthropogenic emissions; and (f) %NO_xSens for New Mexico anthropogenic emissions .

11.2.4 Percent NO_x Sensitive Ozone on June 5, 2014

CAMx estimates 2028 high MDA8 ozone concentrations in excess of the 70 ppb ozone NAAQS on June 5, 2014 in the San Juan Basin and El Paso (Figure 11-4a). In these high ozone locations, ozone formation is split approximately 50%/50% between VOC and NO_x sensitive ozone formation conditions (Figure 11-4b). When looking at just anthropogenic emissions, ozone formation tends to be more NO_x sensitive with %NO_xSens ranging from 60-85% in El Paso and 70-85% in San Juan Basin (Figure 11-4d). Ozone from New Mexico anthropogenic emissions is mainly NO_x sensitive in El Paso on June 5th, but in the San Juan Basin there is more VOC sensitive ozone formation with New Mexico anthropogenic emissions ozone contribution ranging from 1 to 4 ppb (Figure 11-4e and f). In particular, there are large areas of blue shaded %NO_xSens ozone in San Juan County due to New Mexico anthropogenic emissions that indicates that New Mexico VOC and NO_x anthropogenic emissions are equally important to ozone formation in San Juan County on this day. On the other hand, ozone formation within the Permian Basin appears to be more NO_x sensitive on June 5th.

11.2.5 Percent NO_x Sensitive Ozone on July 12, 2014

The total MDA8 ozone on July 12th has elevated ozone concentrations entering New Mexico from the south that appears to have originated in Mexico (Figure 11-5a). Ozone formation from anthropogenic emissions on this day is estimated to occur primarily under NO_x sensitive conditions (%NO_xSens of 86% to 100%; Figure 11-5d). Ozone formation from New Mexico anthropogenic emissions is primarily NO_x sensitive on July 12th with a relative larger amount of VOC sensitive ozone in the south where elevated ozone concentrations occur, but New Mexico's anthropogenic emissions ozone contribution is less than 1 ppb (Figure 11-5e and f).

11.2.6 Percent NO_x Sensitive Ozone on July 24, 2014

On July 24th, the peak MDA8 ozone in the 4-km domain is above the NAAQS (71.1 ppb) and occurs in San Juan County (Figure 11-6a). Although ozone formation is primarily NO_x sensitive across the 4-km NM domain, the largest VOC sensitive ozone due to all emissions (23% or %NO_xSens = 77%) occurs at the location of the peak ozone in San Juan County (Figure 11-6b). However, the amount of VOC sensitive ozone at this location due to anthropogenic emissions is 13% (Figure 11-6d), and less than that (~10%) for anthropogenic emission from New Mexico (Figure 11-6f).

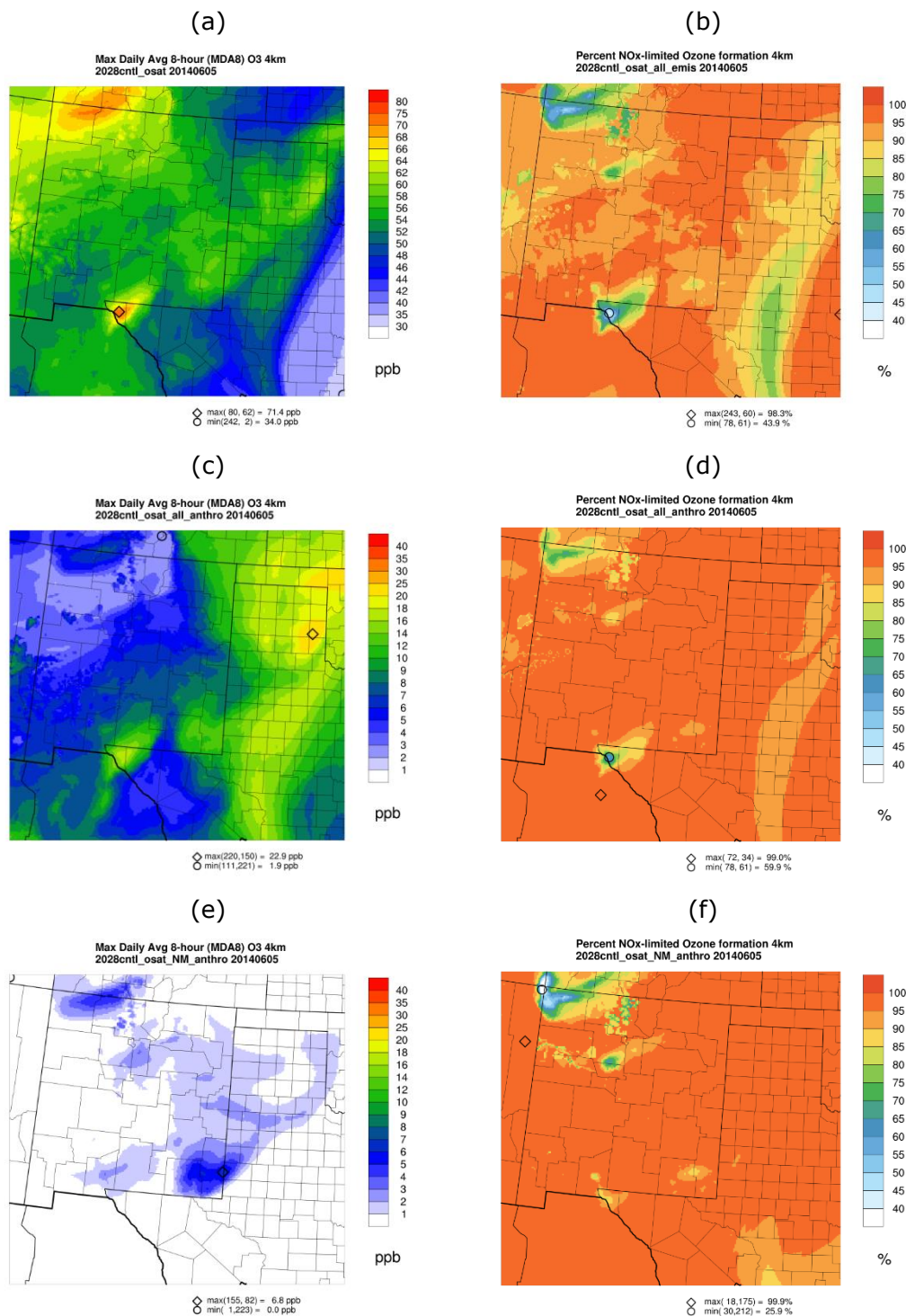


Figure 11-4. 2028 MDA8 ozone (left) and Percent NO_x Sensitive Ozone (right) on June 5, 2014 for: (a) total MDA8 ozone; (c) ozone due to anthropogenic emissions; (e) ozone due to New Mexico anthropogenic emissions; (b) %NO_xSens for all emissions; (d) %NO_xSens for all anthropogenic emissions; and (f) %NO_xSens for New Mexico anthropogenic emissions .

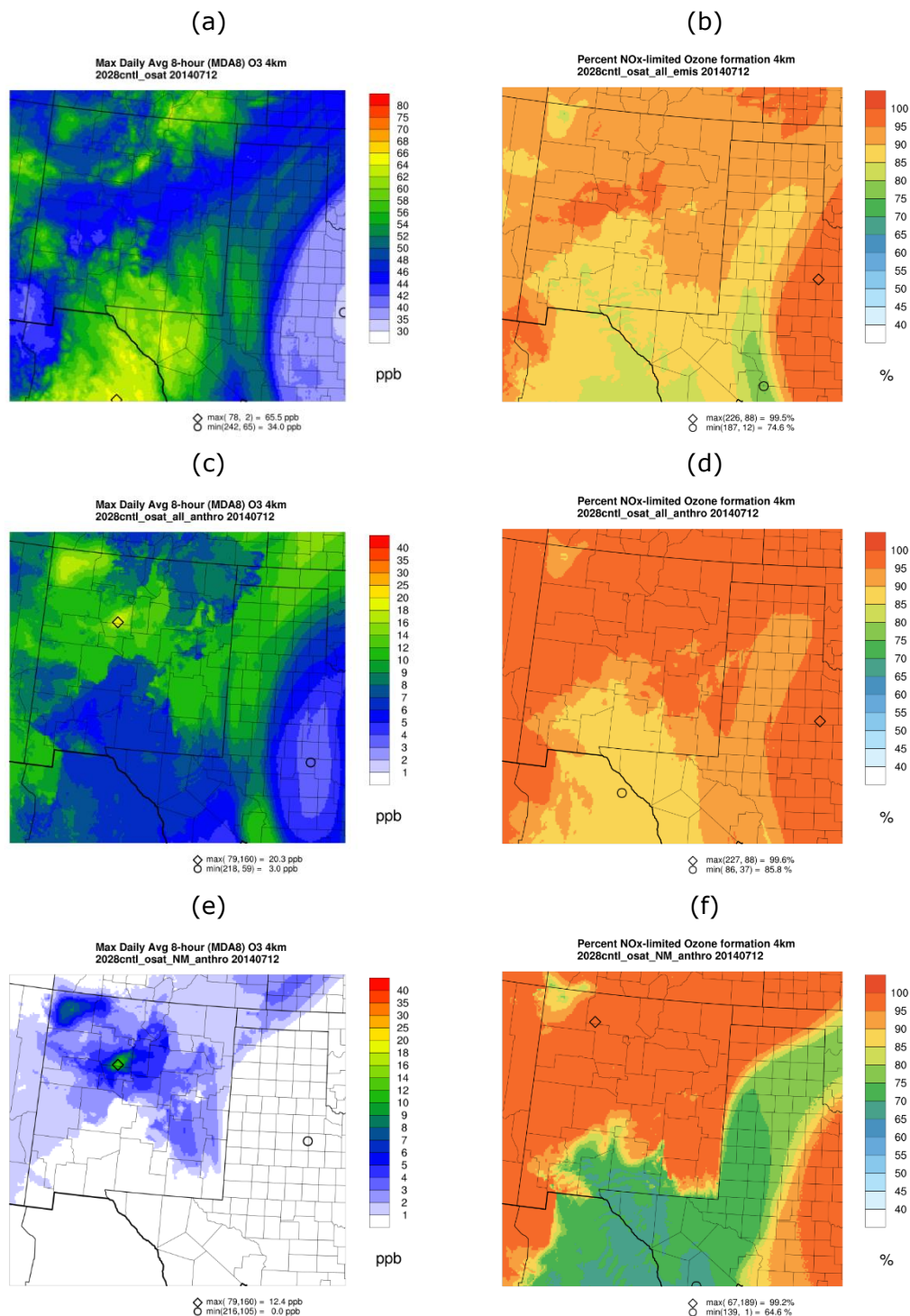


Figure 11-5. 2028 MDA8 ozone (left) and Percent NO_x Sensitive Ozone (right) on July 12, 2014 for: (a) total MDA8 ozone; (c) ozone due to anthropogenic emissions; (e) ozone due to New Mexico anthropogenic emissions; (b) %NO_xSens for all emissions; (d) %NO_xSens for all anthropogenic emissions; and (f) %NO_xSens for New Mexico anthropogenic emissions.

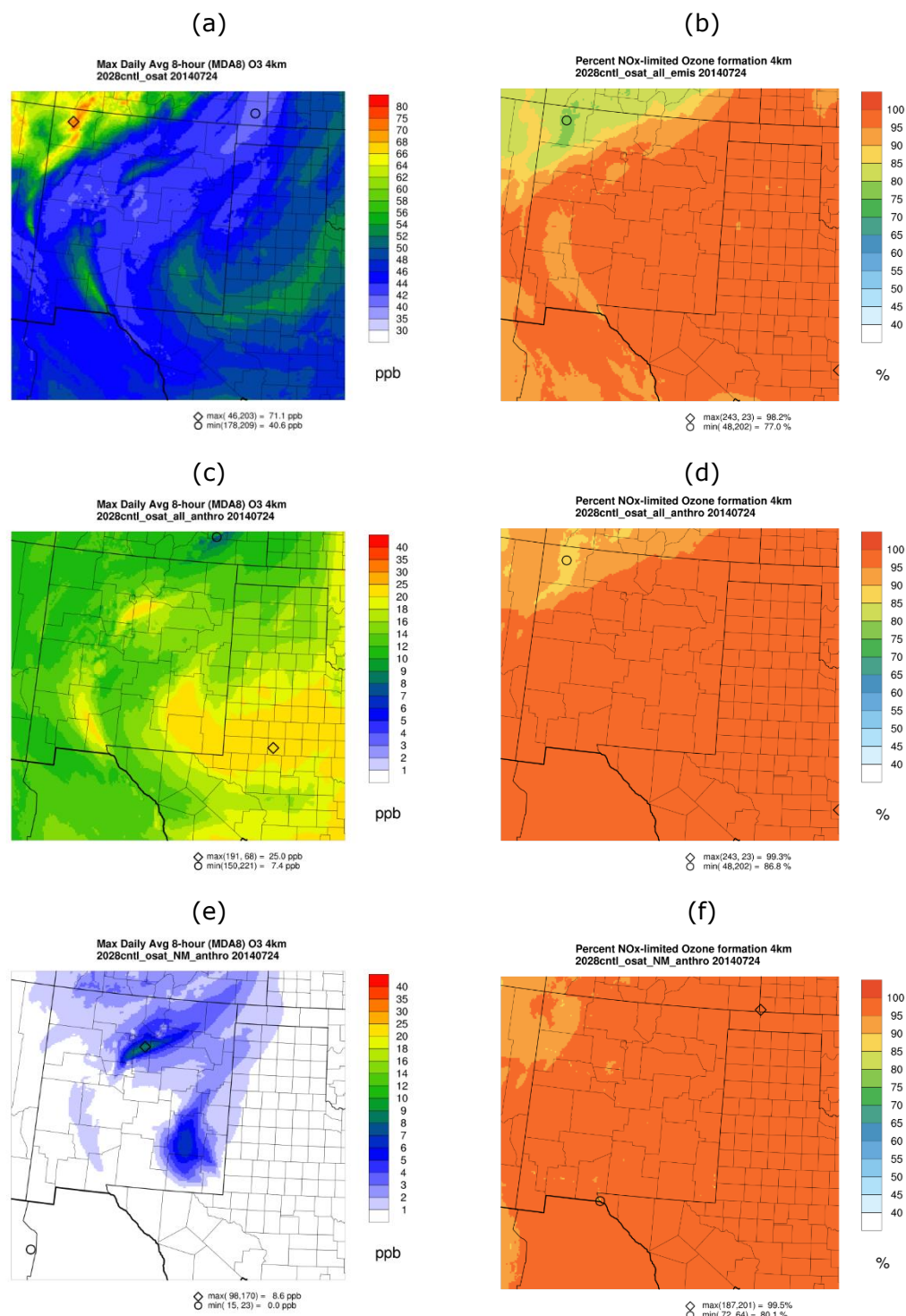


Figure 11-6. 2028 MDA8 ozone (left) and Percent NO_x Sensitive Ozone (right) on July 24, 2014 for: (a) total MDA8 ozone; (c) ozone due to anthropogenic emissions; (e) ozone due to New Mexico anthropogenic emissions; (b) %NO_xSens for all emissions; (d) %NO_xSens for all anthropogenic emissions; and (f) %NO_xSens for New Mexico anthropogenic emissions.

11.2.7 Percent NO_x Sensitive Ozone on July 26, 2014

Modeled elevated MDA8 ozone concentrations occur in northern New Mexico on July 26th with a maximum value above the NAAQS (72 ppb) in northeast Cibola County, west of Albuquerque (Figure 11-7a). Ozone formation is primarily NO_x sensitive across northern New Mexico on this day (%NO_xSens > 85%) with the lowest NO_x sensitivity occurring at the location of the 72 ppb ozone peak in Cibola County (78%; Figure 11-7b). However, the NO_x sensitive ozone formation due to anthropogenic emissions at this location is 88% (Figure 11-7d) with a similar value estimated for anthropogenic emission from New Mexico (Figure 11-7f). New Mexico anthropogenic emissions contribute a significant amount (14 ppb) of the 72 ppb ozone peak in northeast Cibola County (Figure 11-7e). Ozone formation due to New Mexico anthropogenic emissions in the San Juan Basin is more VOC sensitive than the rest of New Mexico on July 26th.

11.2.8 Percent NO_x Sensitive Ozone on August 14, 2014

On August 14th there is modeled elevated MDA8 ozone concentrations in northern Rio Arriba County in the San Juan Basin as well as in southern New Mexico with a peak MDA8 ozone in the 4-km domain of 71.2 ppb in El Paso (Figure 11-8a). Although ozone formation is primarily (85-95%) NO_x sensitive across New Mexico on this day, at the locations of the highest MDA8 ozone concentrations, there is relatively more VOC sensitive ozone formation (Figure 11-8b). At the location of the 71.2 ppb ozone peak in El Paso, the CAMx OSAT simulation estimates that ozone formation due to anthropogenic emissions is ~75% NO_x sensitive and ~25% VOC sensitive. Anthropogenic emissions from New Mexico contribute approximately 1 ppb to the ozone peak in El Paso that is primarily formed under NO_x sensitive conditions (Figure 11-8e and f).

11.2.9 Percent NO_x Sensitive Ozone due to New Mexico Anthropogenic Emissions

Figure 11-9 displays the spatial distribution of the Percent NO_x Sensitive Ozone metric due to New Mexico anthropogenic emissions for 15 example days from the May-August 2014 modeling episode, including the 8 days discussed above. As expected, given its mostly rural nature, the CAMx OSAT simulations estimates that ozone formation due to New Mexico anthropogenic emissions is primarily NO_x sensitive. However, there are several locations where ozone formation is estimated to have relatively higher VOC sensitive ozone formation conditions. The San Juan Basin consistently has higher VOC sensitive ozone formation conditions due to New Mexico anthropogenic emissions. Albuquerque also has higher VOC sensitive ozone formation conditions due to New Mexico anthropogenic emissions, and occasionally, ozone formation in the Permian Basin also has relatively higher VOC sensitive ozone formation. As discussed above, the highest MDA8 ozone conditions also have relatively higher VOC sensitive ozone formation conditions. For example, at the location of the relatively high (58 ppb) MDA8 ozone in San Juan County on May 26th the fraction of VOC sensitive ozone is 32% for all emissions, 31% for all anthropogenic emissions and 55% for New Mexico anthropogenic emissions (Figure 11-2). On May 28th the high ozone (64 ppb) in southern Dona Ana County on the border with Texas has a Percent VOC Sensitive Ozone of 27% for all emissions and 19% for all anthropogenic emissions with New Mexico anthropogenic emissions having Percent VOC

Sensitive Ozone for a secondary peak in the Permian Basin of 25% (Figure 11-3). June 5th is a day where there is high MDA8 ozone in the San Juan and Rio Arriba Counties that is approaching the NAAQS that is split approximately equally between VOC and NO_x sensitive ozone (Figure 11-4). On August 14th the modeled ozone peak exceeds the ozone NAAQS in El Paso and ~30% of the ozone was formed under VOC sensitive conditions (Figure 11-8).

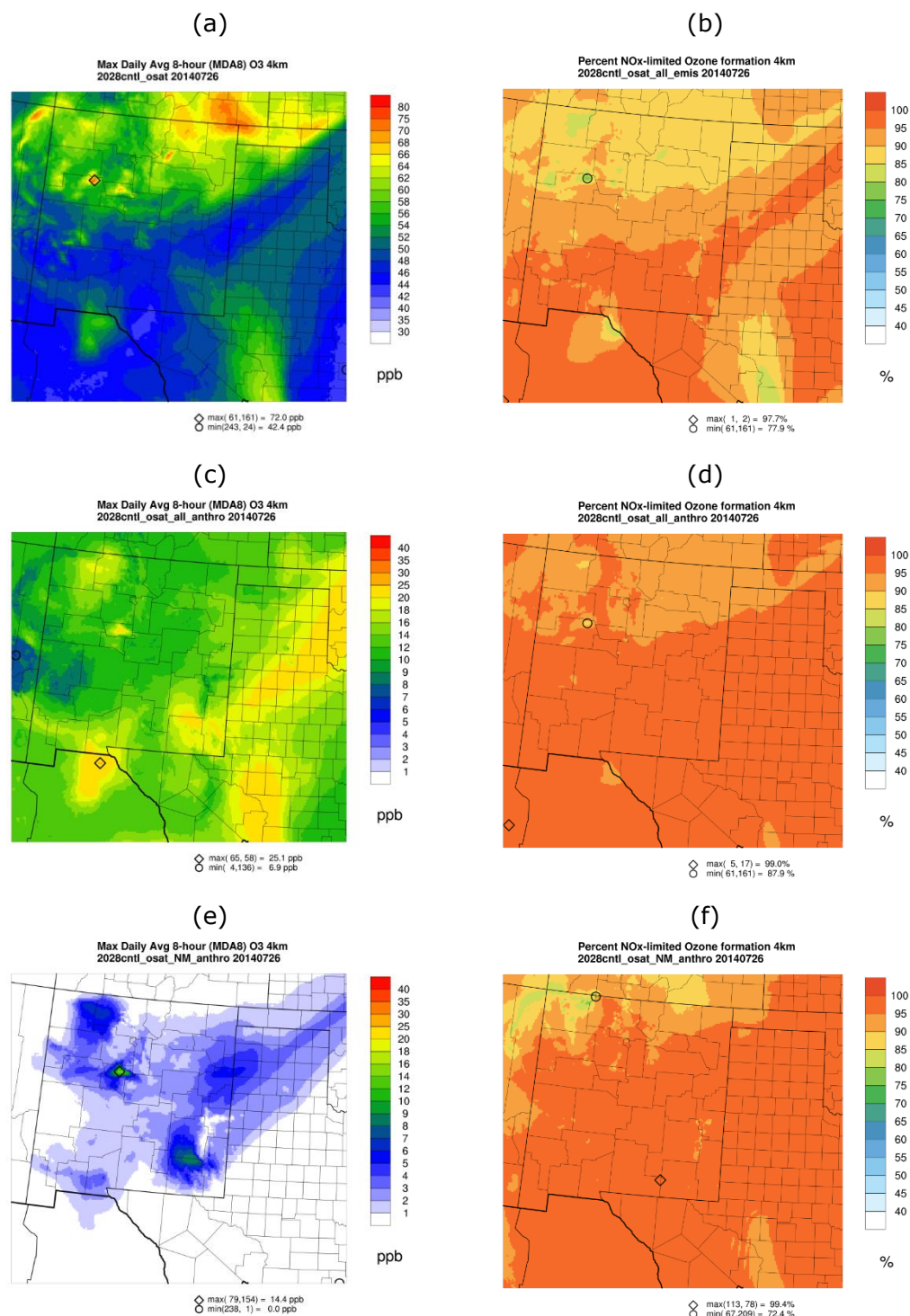


Figure 11-7. 2028 MDA8 ozone (left) and Percent NO_x Sensitive Ozone (right) on July 26, 2014 for: (a) total MDA8 ozone; (c) ozone due to anthropogenic emissions; (e) ozone due to New Mexico anthropogenic emissions; (b) %NO_xSens for all emissions; (d) %NO_xSens for all anthropogenic emissions; and (f) %NO_xSens for New Mexico anthropogenic emissions.

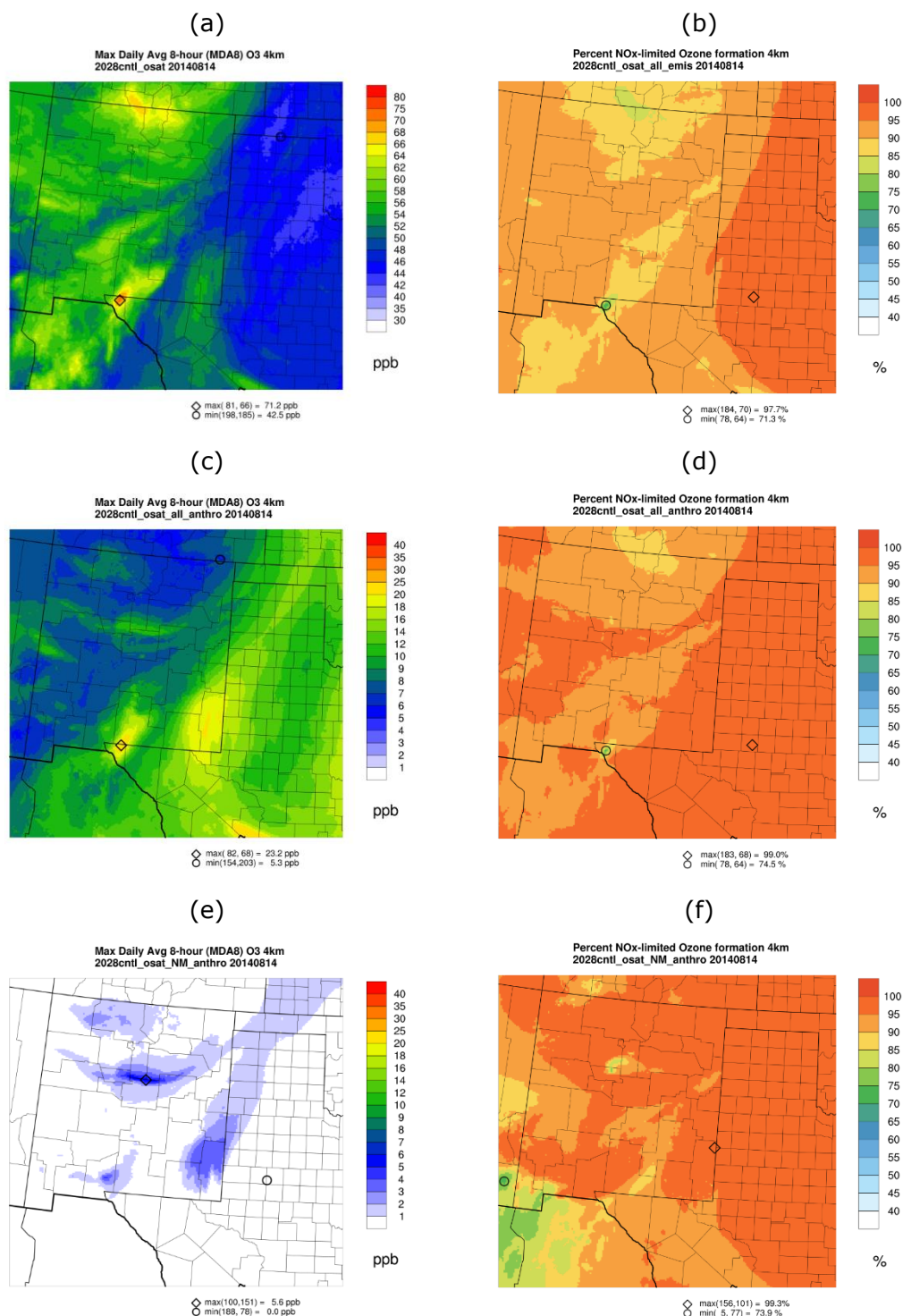


Figure 11-8. 2028 MDA8 ozone (left) and Percent NO_x Sensitive Ozone (right) on August 14, 2014 for: (a) total MDA8 ozone; (c) ozone due to anthropogenic emissions; (e) ozone due to New Mexico anthropogenic emissions; (b) %NO_xSens for all emissions; (d) %NO_xSens for all anthropogenic emissions; and (f) %NO_xSens for New Mexico anthropogenic emissions.

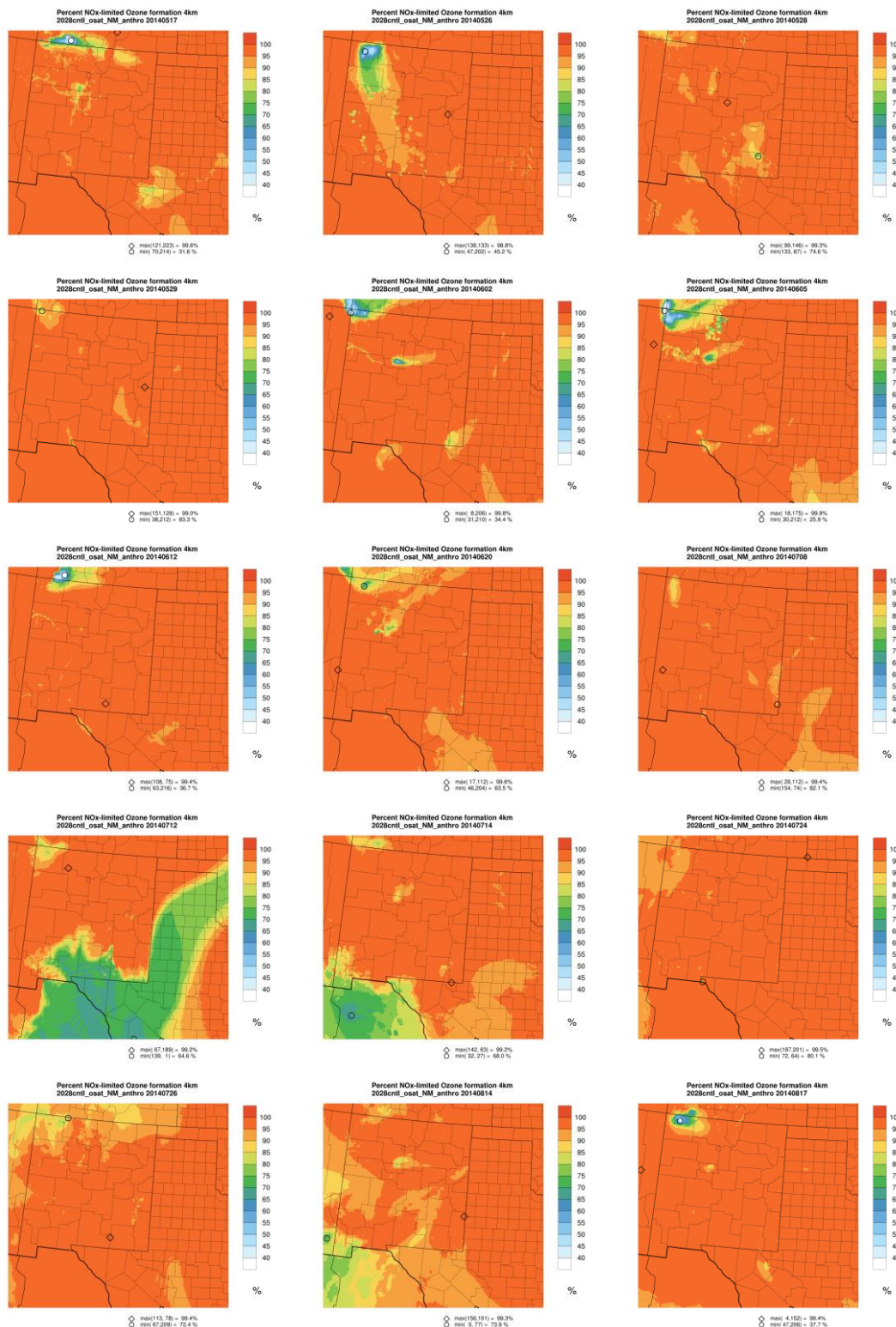


Figure 11-9. Spatial distribution of Percent NO_x Sensitive Ozone due to New Mexico anthropogenic emissions across the 4-km New Mexico domain for 15 days of relatively higher MDA8 ozone concentrations.

11.3 Analysis of VOC/NO_x Ozone Formation Sensitivity at Monitoring Sites in New Mexico

The CAMx 2028 OSAT ozone source apportionment results were extracted at the locations of the New Mexico monitoring sites and loaded into an Excel Dashboard where the source apportionment contributions to daily MDA8 ozone concentrations can be visualized. The Dashboard displays the OSAT source apportionment O3V and O3N results for groups of 10 days and the average across the 10 days for different combinations of the 3 Source Categories and 5 Source regions within the CAMx modeling domain, with examples for several monitoring sites discussed below.

11.3.1 VOC/NO_x Sensitivity at Substation in San Juan County

Figure 11-10 displays the CAMx OSAT results at the Substation site in San Juan County using daily stacked bar charts of O3V and O3N for the 10 days used by SMAT to make the 2028 ozone DVF projections, along with a pie chart of the O3V and O3N results averaged across the 10 SMAT days. The Dashboard can also display results for the highest and second highest 10 modeled MDA8 ozone concentration days from the CAMx 2028 O&G Control Strategy simulation. As discussed in Chapter 7, the 10 SMAT days are selected as the 10 days with the highest modeled MDA8 ozone near the monitor in the CAMx 2014v2 Base Case, so there is a lot of overlap in days between the 10 SMAT days and the 10 highest modeled 2028 MDA8 ozone days.

The displays in Figure 11-10 use warmer colors (e.g., red) for the NO_x sensitive ozone O3N and cooler colors (e.g., blue) for the VOC sensitive ozone O3V. Emissions within the CAMx domain contribute from 6 to 36 ppb to the total MDA8 ozone across the 10 SMAT days at Substation, with a vast majority of the ozone formed being NO_x sensitive, whose daily variation ranges from approximately 70% to 90% of the SMAT 10 days daily MDA8 ozone concentrations due to emissions (Figure 11-10, top). Averaged across the 10 SMAT days, the total MDA8 ozone at Substation is 63.7 ppb with 67% of that due to BCs and the rest (21.1 ppb) due to in-domain emissions, of which 81% is NO_x sensitive and 19% is VOC sensitive (Figure 11-10, bottom). Since Figure 11-10 is for all emissions sources, the region-specific stacked bars and pie slices display the contributions of anthropogenic, fire and natural emissions from all of the Source Regions.

The Dashboard can be used to isolate the amount of VOC and NO_x sensitive ozone from the different Source Categories and Regions used in the CAMx OSAT simulation with two example pie charts averaged across the 10 SMAT days at Substation shown in Figure 11-11. The top pie chart in Figure 11-11 shows ozone contributions averaged across the 10 SMAT days for all anthropogenic emissions and all Source Regions. All emissions in the domain contributed 21.1 ppb to the average of the 10 SMAT days at Substation of which 11.4 is due to the anthropogenic emissions (Figure 11-11, top) so the remainder (9.7 ppb) is due to natural and fire emissions. Of the 11.4 ppb all anthropogenic emissions ozone contribution, 91% was formed under NO_x sensitive and 9% was formed under VOC sensitive conditions. The bottom pie chart in Figure 11-11 shows the contributions to the average of the 10 SMAT days at Substation due to anthropogenic emissions from New Mexico and shows that New Mexico is

contributing 42% of the anthropogenic emissions contribution (4.7 of 11.4 ppb) at Substation with most of that (87%) being NO_x sensitive ozone.

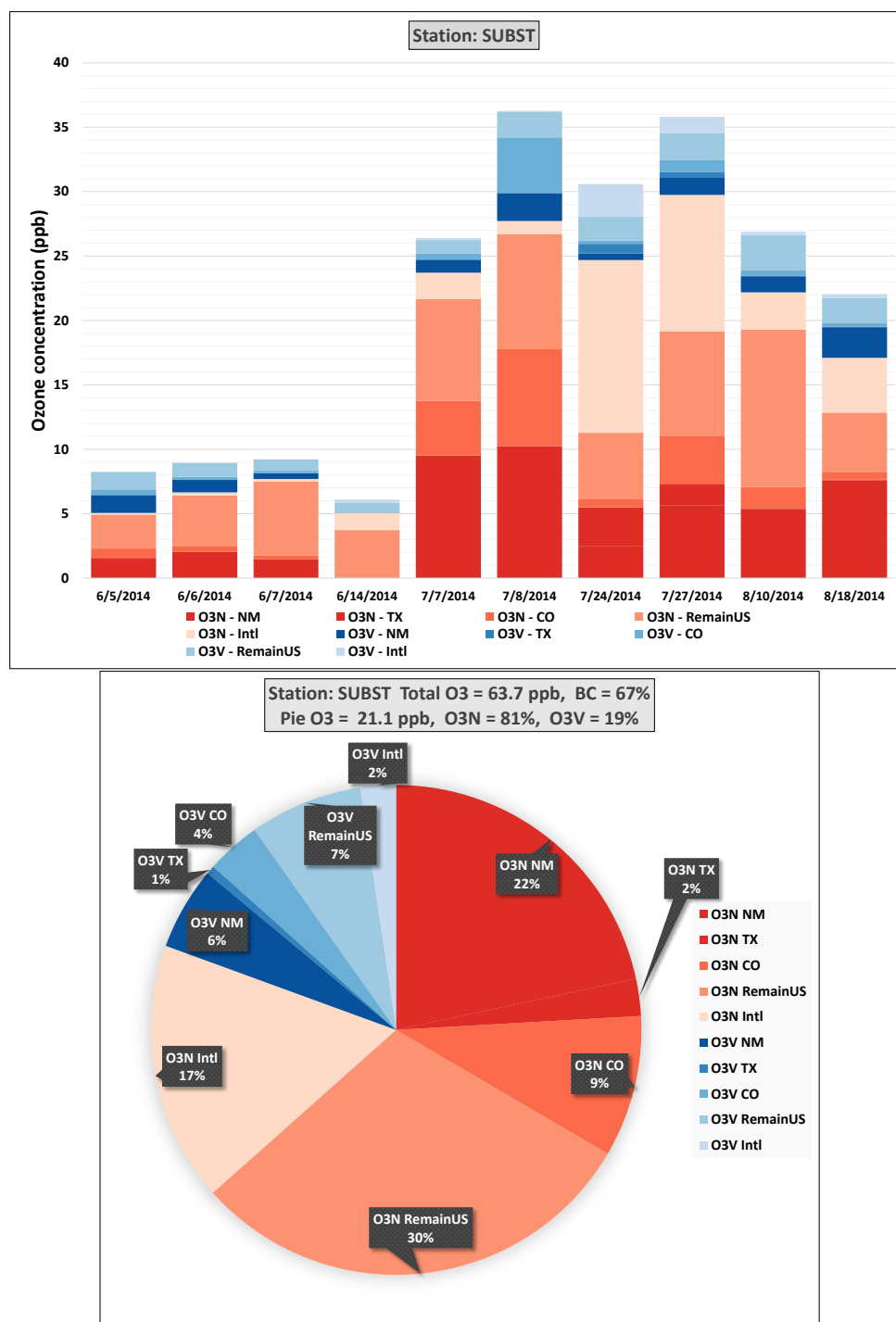


Figure 11-10. Bar Chart of daily O3V (blue) and O3N (red) contributions across the 10 days used by SMAT and pie chart of ozone contributions averaged across the 10 SMAT days for all Source Categories and Source Regions and the Substation monitor in San Juan County.

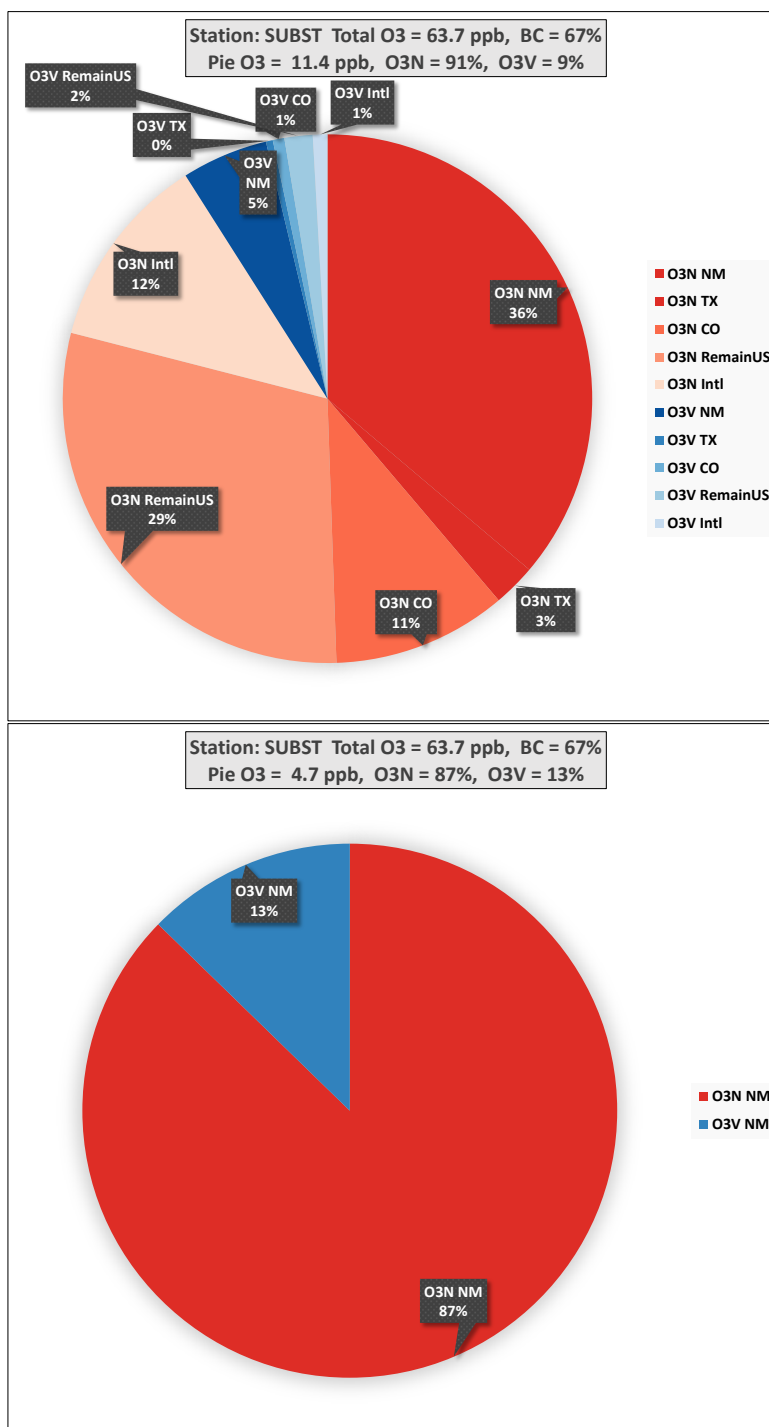


Figure 11-11. O3V and O3N contributions averaged across the 10 SMAT days at Substation for all anthropogenic emissions (top) and New Mexico anthropogenic emissions (bottom).

11.3.2 VOC/NO_x Sensitivity at South East Heights in Bernalillo County

The CAMx OSAT source apportionment results for the 10 SMAT days and all sources at the South East Heights monitoring in Bernalillo County are shown in Figure 11-12. There is a lot of day-to-day variability across the 10 SMAT days with in-domain emissions estimated to contribute from 10 to 40 ppb, with the remainder of the ozone coming from the BCs. On the two lowest in-domain emissions ozone days (June 7 and 8 with 10 and 11 ppb ozone from in-domain emissions), the ozone is almost completely (> 90%) NO_x sensitive, whereas on other days the VOC sensitive ozone can exceed 20% (e.g., August 29). This daily variation in VOC and NO_x sensitivity in Bernalillo County was also seen in the spatial maps (e.g., Figure 11-9). Averaged across the 10 SMAT days at South East Heights, in-domain emission sources contribute 25.4 ppb, of which 87% is NO_x sensitive ozone with the O3N from New Mexico (30%), remainder U.S. (26%) and international (25%) being the highest contributors.

A vast majority (93%) of the 14.5 ppb anthropogenic emissions ozone contribution at South East Heights was formed under NO_x sensitive conditions (Figure 11-12, top) with over half of that coming from New Mexico (7.4 ppb) that was also primarily (92%) NO_x sensitive ozone (Figure 11-13, bottom).

11.3.3 VOC/NO_x Sensitivity at Desert View in Doña Ana County

The CAMx OSAT results for the Desert View monitoring site in Doña Ana County are shown in Figures 11-14 and 11-15. Ozone from Texas and Mexico contributes greatly to ozone levels at Desert View. This includes ozone from El Paso that can have a higher fraction of VOC sensitive ozone (e.g., see Figure 11-4) that is seen on some days in the daily bar charts in Figure 11-14 (e.g., July 24, 2014). Emissions within the CAMx domain contribute 24 to 46 ppb of the daily MDA8 ozone on the 10 SMAT days at Desert View with 14 to 28 ppb of that being anthropogenic in origin. Across all emissions, the average of the 10 SMAT days is 81% NO_x sensitive, with the anthropogenic component of ozone being much more NO_x sensitive (90%) than the natural/fire component (69%). New Mexico anthropogenic emissions contribute 2 ppb (10%; Figure 11-15, bottom) of the 20.9 ppb anthropogenic ozone (Figure 11-15, top) at Desert View with emissions from Mexico contributing approximately half (10.6 ppb) and Texas (3.9 ppb), almost 20%.

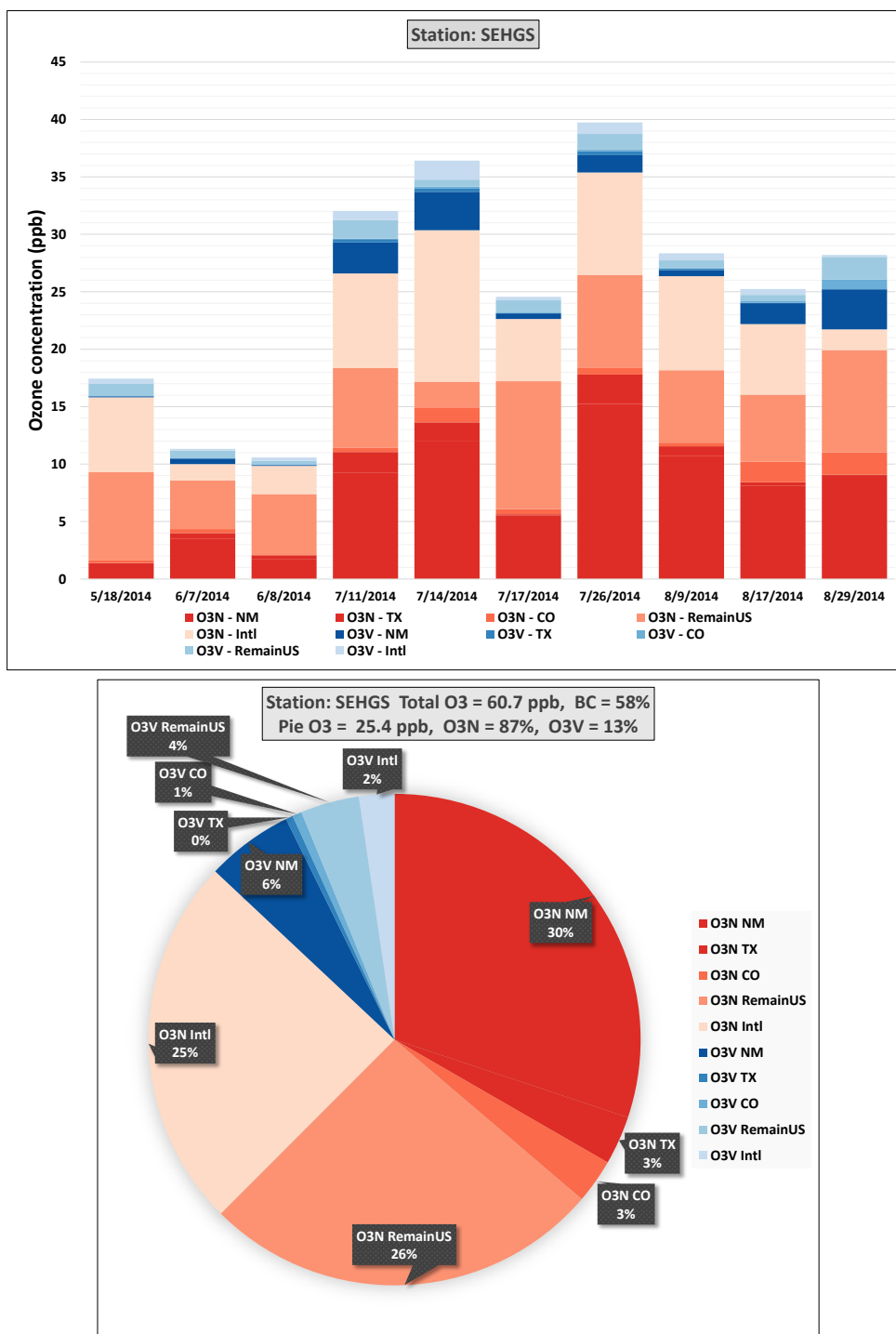


Figure 11-12. Bar Chart of daily O3V (blue) and O3N (red) contributions across the 10 days used by SMAT and pie chart of ozone contributions averaged across the 10 SMAT days for all Source Categories and Source Regions and the South East Heights monitor in Bernalillo County.

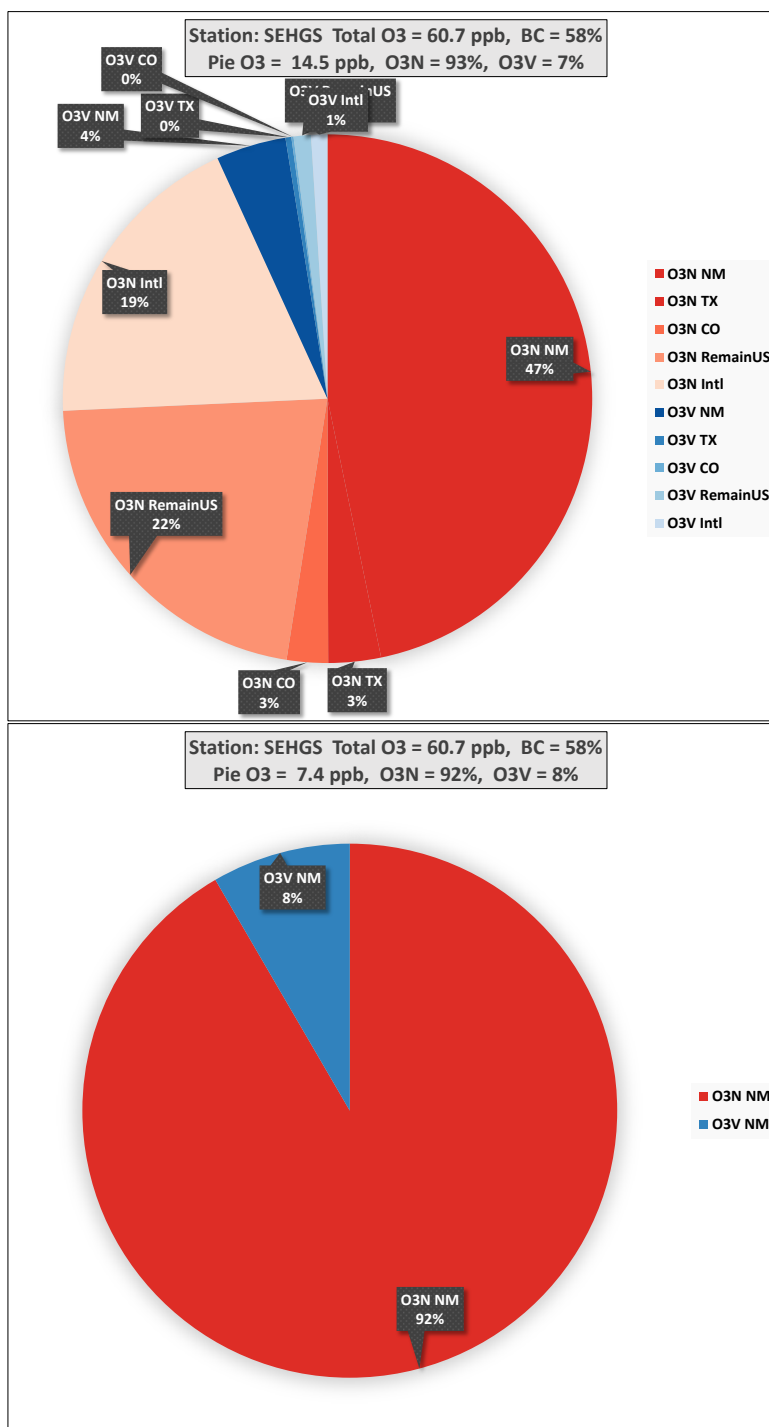


Figure 11-13. O₃V and O₃N contributions averaged across the 10 SMAT days at South East Heights monitoring site for all anthropogenic emissions (top) and New Mexico anthropogenic emissions (bottom).

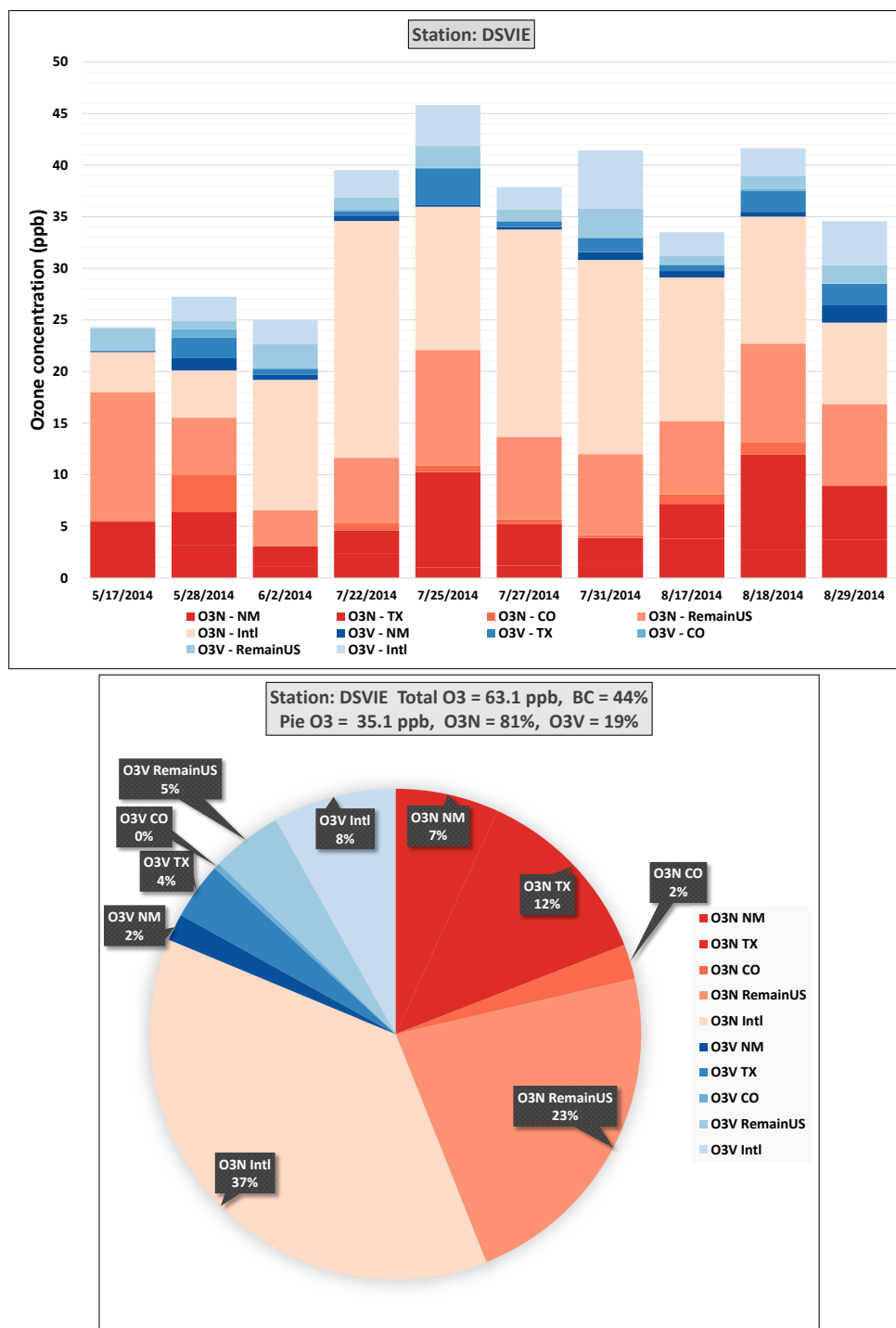


Figure 11-14. Bar Chart of daily O3V (blue) and O3N (red) contributions across the 10 days used by SMAT and pie chart of ozone contributions averaged across the 10 SMAT days for all Source Categories and Source Regions and the Desert View monitor in Doña Ana County.

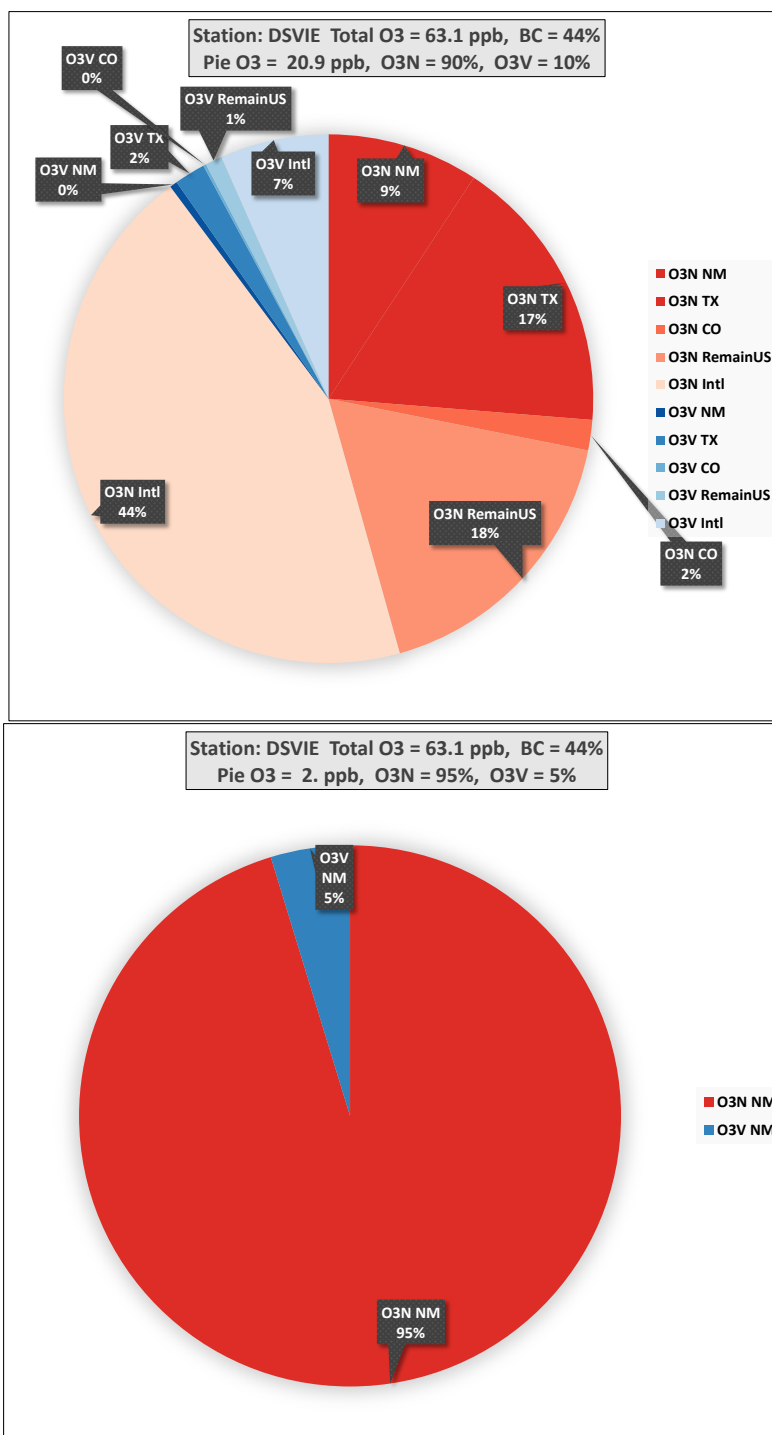


Figure 11-15. O3V and O3N contributions averaged across the 10 SMAT days at Desert View monitoring site for all anthropogenic emissions (top) and New Mexico anthropogenic emissions (bottom).

11.3.4 VOC/NO_x Sensitivity at Carlsbad in Eddy County

Figures 11-16 and 11-17 display the CAMx 2028 OSAT results at the Carlsbad monitor in Eddy County. Across the 10 SMAT days, emissions within the CAMx domain account for 11 to 27 ppb of the daily ozone at Carlsbad (Figure 11-16, top). The model estimates more NO_x sensitive ozone at Carlsbad (91% on average) than Desert View (81% on average). The ozone due to emissions averaged across the 10 SMAT days at Carlsbad is 19.1 ppb that is approximately equally split between anthropogenic (10.0 ppb) and natural/fire (9.1 ppb) sources, with the ozone from the anthropogenic emissions (94%) being more NO_x sensitive than the ozone from the natural/fire emissions (87%). Of the 10 ppb from anthropogenic emissions, almost half (4.7 ppb) is from international emissions with anthropogenic emissions from New Mexico and Texas both contributing 16% (1.6 ppb) each (Figure 11-17).

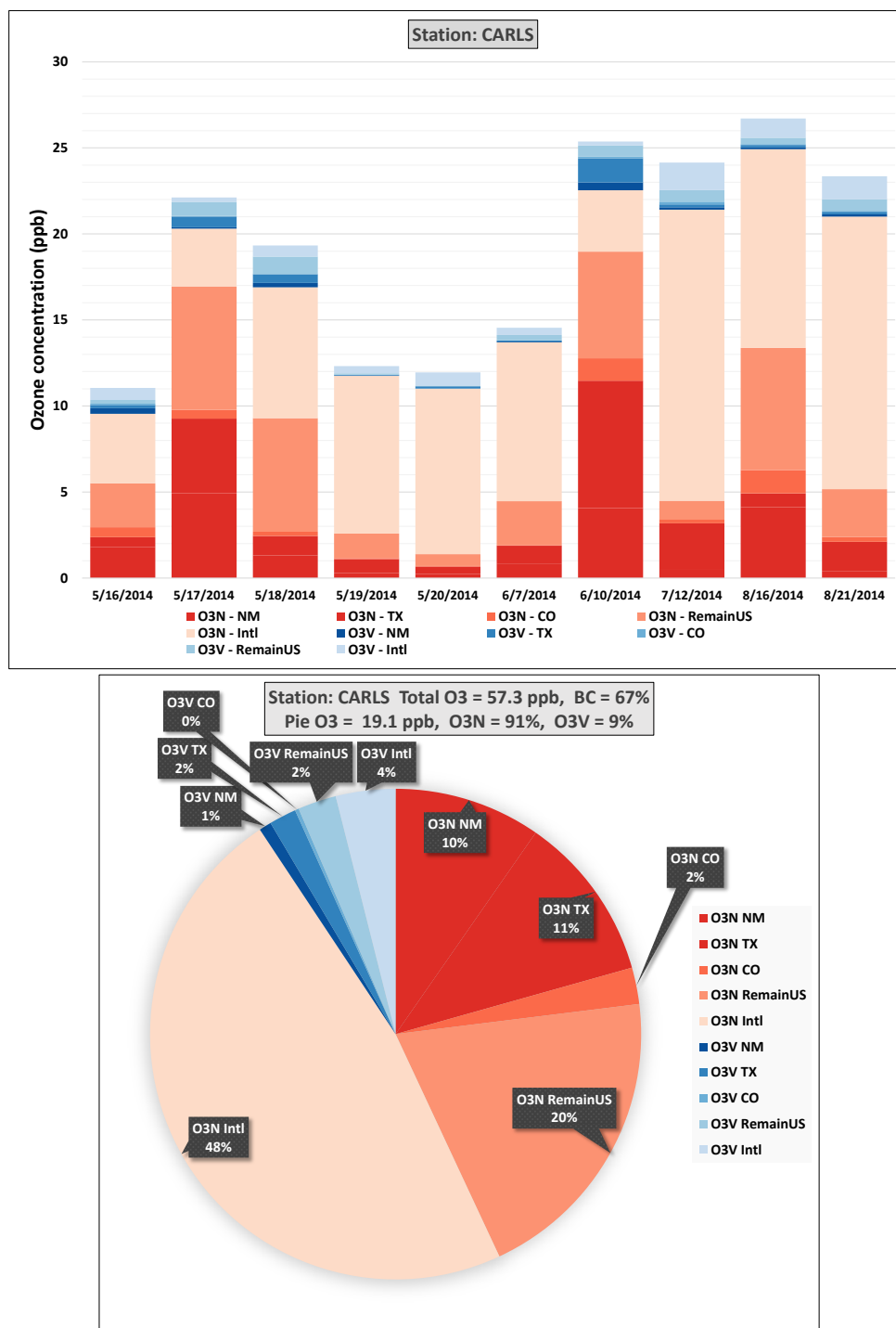


Figure 11-16. Bar Chart of daily O3V (blue) and O3N (red) contributions across the 10 days used by SMAT and pie chart of ozone contributions averaged across the 10 SMAT days for all Source Categories and Source Regions and the Carlsbad monitor in Eddy County.

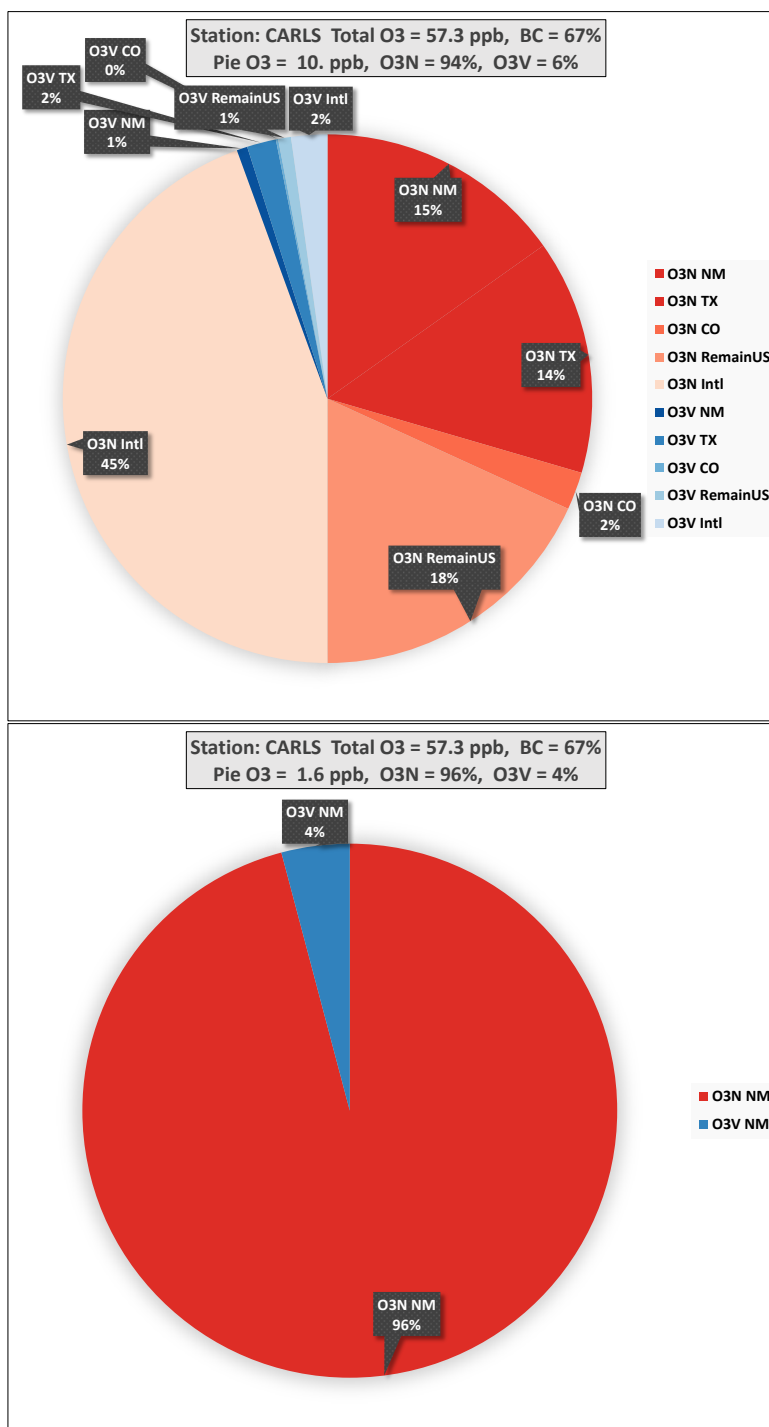


Figure 11-17. O3V and O3N contributions averaged across the 10 SMAT days at Carlsbad monitoring site for all anthropogenic emissions (top) and New Mexico anthropogenic emissions (bottom).

12. SUMMARY AND CONCLUSIONS

12.1 Summary of CAMx 2014 36/12/4-km Photochemical Model Platform Development

A CAMx 2014 36/12/4-km ozone modeling platform was developed with the 4-km domain focused on New Mexico and adjacent states. The CAMx 2014 36/12/4-km modeling platform was based on the Western Regional Air Partnership (WRAP), Western Air Quality Study (WAQS) CAMx 2014 36/12-km modeling platform. WRF meteorological modeling was conducted to generate CAMx meteorological inputs for the 36/12/4-km domains and summer of 2014. A model performance evaluation was conducted that compared CAMx 2014 estimated ozone concentrations with concurrent ozone observations that produced good ozone model performance. A revised CAMx 2014v2 base case was conducted with a newer version of the CAMx model and updated biogenic emissions that also produced very good ozone model performance.

SMOKE emission and CAMx ozone modeling was conducted for a 2014v2 Base Case, a 2028 Base Case and a 2028 O&G Control Strategy that implemented O&G controls on O&G sources in the New Mexico portions of the San Juan and Permian Basins. The proposed New Mexico O&G ozone precursor rule controls were implemented in the 2028 Base Case NM O&G emissions by Eastern Research Group (ERG) under separate contract with NMED.

12.2 Summary of 2028 Ozone Modeling Results and Ozone Design Value Projections

2028 projected future year ozone design values (DVF) were made using the CAMx 2014v2, 2028 Base Case and 2028 O&G Control Strategy modeling results following EPA's latest photochemical modeling guidance (EPA, 2018). EPA's modeling guidance recommends scaling the current year design value (DVC) using a Relative Response Factor (RRF) based on the ratio of the future to current year modeling results (i.e., $RRF = \text{CAMx Ozone}_{2028} / \text{CAMx Ozone}_{2014}$). The guidance recommends using a DVC based on an average of three ozone design values centered on the base modeling year, which in this case is 2014, so design values from 2012-2016 are used (i.e., $DVC_{2012-2016}$). Following EPA's ozone projection approach guidance, all 2028 projected ozone DVFs were below the 2015 ozone NAAQS at all monitoring sites in New Mexico using the $DVC_{2012-2016}$ observed ozone starting point for the projections.

A comparison of the CAMx absolute modeled daily MDA8 ozone concentrations for the 2028 Base Case and 2028 O&G Control Strategy found that the strategy resulted in MDA8 ozone reductions over large areas of New Mexico, with the largest ozone reductions occurring in the San Juan and Permian Basins. However, there were also isolated areas of ozone increases due to the 2028 O&G Control Strategy that usually occurred in or near the San Juan and Permian Basins that are likely due to "NO_x Disbenefits" where NO_x emission reductions can cause localized ozone increases. For at least one day (June 5, 2014) that CAMx 2028 Base Case had a large area with MDA8 ozone concentrations that exceeded the 70 ppb ozone NAAQS in San Juan County, the 2028 O&G Control Strategy was sufficient to reduce the MDA8 ozone concentrations to below the NAAQS. On

another day (July 24, 2014), the “NO_x Disbenefits” of the 2028 O&G Control Strategy was sufficient to increase the MDA8 ozone concentrations in one 4-km grid cell in San Juan County that was below the NAAQS in the 2028 Base Case to right at the threshold for exceeding the NAAQS (71.0 ppb) in the 2028 O&G Control Strategy.

12.3 Sensitivity of 2028 Ozone Design Value Projections to Current Year Ozone Design Value

Given the upward trend in ozone design values in southern New Mexico in recent years (see Table 1-1), the sensitivity of the 2028 future year ozone DVF projections to the current year ozone design value (DVC) was investigated by making 2028 ozone DVF projections using current year design values based on observations from 2015-2019 (i.e., DVC₂₀₁₅₋₂₀₁₉) and 2017-2019 (i.e., DV₂₀₁₇₋₂₀₁₉) instead of the DVC₂₀₁₂₋₂₀₁₆ current year design value recommended in EPA’s ozone modeling guidance (EPA, 2018).

There were four monitoring sites with DVC₂₀₁₅₋₂₀₁₉ exceeding the 70 ppb ozone NAAQS, compared to two using the DVC₂₀₁₂₋₂₀₁₆. The Carlsbad site projected 2028 ozone DVF (71.2 ppb) still exceeded the ozone NAAQS for the 2028 Base Case when the DVC₂₀₁₅₋₂₀₁₉ current year design value was used in the projection. However, the emission reductions in the 2028 O&G Control Strategy were sufficient to bring the projected 2028 ozone DVF at the Carlsbad site (70.9 ppb) to below the ozone NAAQS in the DVC₂₀₁₅₋₂₀₁₉ current year design value sensitivity analysis.

Three monitors exceeded the 70 ppb ozone NAAQS using the most recent ozone design value (DV₂₀₁₇₋₂₀₁₉), but one of the sites that had their DVC₂₀₁₅₋₂₀₁₉ exceeding the NAAQS was no longer in operation in 2017-2019 (i.e., Carlsbad Caverns NP). Two of the sites were still estimated to have projected 2028 ozone DVFs that exceeded the ozone NAAQS for both the 2028 Base Case and 2028 O&G Control Strategy in the DV₂₀₁₇₋₂₀₁₉ current year DVC sensitivity analysis. Under the 2028 O&G Control Strategy, the projected 2028 ozone DVFs at Carlsbad and Desert View were, respectively, 76.0 and 71.4 ppb using the DV₂₀₁₇₋₂₀₁₉ as the current year DVC in the ozone projections.

There were significant increases in O&G emissions within the Permian Basin since 2014 that are not accounted for in the CAMx ozone modeling results in the DVC₂₀₁₅₋₂₀₁₉ and DV₂₀₁₇₋₂₀₁₉ current year design value sensitivity tests. If those additional O&G emissions were included in the CAMx base year base case simulations, the projected 2028 ozone DVFs would be lower in the vicinity of the Permian Basin because of the higher denominator in the RRF projections factors due to higher O&G emissions than occurred in 2014.

EPA recommends using the average of three years of design values for the DVC as it is more stable and has less year-to-year variability than a single design value period (EPA, 2018, pp. 101⁴²). So, the 2028 ozone DVFs projection sensitivity test using the DV₂₀₁₇₋₂₀₁₉ has an additional caveat as it is less stable and more influenced by year-to-year variability in ozone concentrations.

⁴² https://www.epa.gov/sites/production/files/2020-10/documents/o3-pm-rh-modeling_guidance-2018.pdf

12.4 2028 Source Sector APCA Ozone Source Apportionment Modeling

The 2028 O&G Control Strategy Source Sector APCA ozone source apportionment modeling found that approximately half to two-thirds of the ozone on high MDA8 ozone days in New Mexico is due to Boundary Conditions (BCs) that are mainly from international and natural emissions from outside of the CAMx 36-km North America modeling domain. The highest contributing New Mexico Source Sector varied by location. For sites in San Juan County in northwestern New Mexico, EGU and O&G Non-Point sources were the two highest contributing Source Sectors followed by O&G Point sources. For sites in Bernalillo County in the central part of New Mexico, Other Anthropogenic, On-Road and Non-Road were the highest contributing Source Sectors. In Doña Ana County in southern New Mexico, New Mexico EGU and On-Road were the highest contribution Source Sectors. O&G Non-Point and Point sources were the highest contributing New Mexico Source Sectors at the Carlsbad and Hobbs sites in southeastern New Mexico. Texas and Mexico had large contributions to ozone in southern New Mexico, whereas Colorado had large contributions in northwestern New Mexico.

International anthropogenic emissions contributed 13 to 26 ppb to the projected 2028 ozone DVFs at New Mexico sites, with larger international contributions at the southern New Mexico sites. The elimination of the contributions of international anthropogenic emissions reduced the projected 2028 ozone DVFs to below 60 ppb under all scenarios, even when the $DVC_{2017-2019}$ was used that produced a projected 2028 ozone DVF at Carlsbad that exceeded both the 2008 and 2015 ozone NAAQS.

12.5 2028 VOC/NO_x Sensitivity OSAT Ozone Source Apportionment Modeling

The 2028 VOC/NO_x Sensitivity OSAT ozone source apportionment simulation found that ozone formation across New Mexico was primarily NO_x sensitive. There were some areas that had relatively higher VOC sensitive ozone formation conditions on some days, including the San Juan Basin, Albuquerque, the Texas part of El Paso, and to a lesser extent, the Permian Basin. There are even days (e.g., June 5th) where elevated MDA8 ozone concentrations in San Juan Basin that approached the ozone NAAQS and ozone formation was approximately evenly split between NO_x and VOC sensitive ozone formation conditions. But overall, ozone formation was more NO_x sensitive than VOC sensitive. The highest modeled ozone concentrations tend to have relatively higher VOC sensitive ozone concentrations. Thus, although ozone formation appears to be mainly NO_x sensitive, VOC controls will also have benefits in reducing some of the highest ozone concentrations in New Mexico.

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

NOV 29 2018

OFFICE OF
AIR QUALITY PLANNING
AND STANDARDS

MEMORANDUM

SUBJECT: Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM_{2.5} and Regional Haze

FROM: Richard A. Wayland, Division Director
Air Quality Assessment Division

A handwritten signature in blue ink, which appears to read "James H. For", is written over the "FROM:" line.

TO: Regional Air Division Directors, Regions 1 – 10

The Environmental Protection Agency (EPA) is issuing the attached *Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM_{2.5} and Regional Haze*. This document reflects the EPA's recommendations for how air agencies should conduct air quality modeling and related technical analyses to satisfy model attainment demonstration requirements for the 2015 ozone and 2012 PM_{2.5} National Ambient Air Quality Standards (NAAQS), as well as for regional haze reasonable progress analyses. This document updates the previous draft version of the modeling guidance, which was released in December 2014.

This document does not substitute for provisions or regulations of the Clean Air Act (CAA), nor is it a regulation itself. As the term "guidance" suggests, it provides recommendations on how to implement the modeling requirements. Thus, it does not impose binding, enforceable requirements on any party, nor does it assure that the EPA will approve all instances of its application, as the guidance may not apply to a particular situation based upon the circumstances. Final decisions by the EPA regarding a particular State Implementation Plan (SIP) demonstration will only be made based on the statute and applicable regulations and will only be made following a final submission by air agencies and after notice and opportunity for public review and comment.

In December 2014, the EPA released a draft version of this guidance for public review and comment. A total of 13 substantive comments were received. After considering the comments, the EPA made changes which are reflected in this updated version of the guidance. Major guidance updates include responding to the public comments as well as updates to reflect requirements in the most recent NAAQS implementation rules and regional haze rule.

Similar to the draft guidance, the updated guidance is divided into two main sections. The first part describes how to setup and apply a photochemical modeling platform (including meteorological, emissions, and air quality modeling), and the second part describes how to use the air quality modeling results to show whether future attainment of the ozone and/or PM_{2.5} NAAQS is likely. The guidance also describes how to use photochemical grid modeling to evaluate reasonable progress goals for regional haze.

Many of guidance updates are in the form of revised and reorganized text. In addition, numerous references have been added and/or updated. The updated guidance reflects the requirements contained in the 2015 ozone NAAQS SIP requirements rule (November 2018)¹, the 2012 PM_{2.5} NAAQS SIP requirements rule (August 2016)², and the regional haze rule (January 2017)³.

Specific updates to the draft guidance include:

- Reorganization of the document including removal of outdated language and references.
- The 2014 draft guidance updates to the recommended 8-hour ozone attainment test (relative response factors using the top ten modeled days) were finalized, and now also apply to the 2015 ozone NAAQS.
- Consistent with the 2017 regional haze rule revisions, the reasonable progress goals methodology has been updated to reference the 20 percent “most anthropogenically impaired” days and 20 percent “clearest” days.
- The emissions modeling section has been extensively updated to account for new and improved emissions models, techniques, and input data, and has been closely coordinated with the SIP emissions inventory guidance, “*Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations*,” available at: <https://www.epa.gov/air-emissions-inventories/air-emissions-inventory-guidance-implementation-ozone-and-particulate>.

Please share this guidance with air agencies in your Region. If you have any questions concerning this document, please contact Brian Timin at (919) 541-1850 or timin.brian@epa.gov. The guidance document is available electronically on the EPA’s website: <https://www.epa.gov/scram/state-implementation-plan-sip-attainment-demonstration-guidance>.

Attachment

¹ See <https://www.epa.gov/ground-level-ozone-pollution/implementation-2015-national-ambient-air-quality-standards-ozone>

² See 81 FR 58101

³ See 82 FR 3078



Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM_{2.5}, and Regional Haze

Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM_{2.5}, and Regional Haze

U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Air Quality Assessment Division
Research Triangle Park, NC

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1.0 Introduction

This document describes how to estimate the impacts of an emissions control strategy on air quality for purposes of demonstrating attainment of the annual average and 24-hour average national ambient air quality standards (NAAQS) for particles smaller than 2.5 µm in diameter ($PM_{2.5}$) and the 8-hour NAAQS for ozone. We also describe how to use modeled and monitored air quality data to estimate future visibility conditions in *Class I areas* (e.g., national parks, wilderness areas) as part of the development of reasonable progress goals (RPGs) that reflect the long-term strategy in a regional haze state implementation plan (SIP).¹

This document describes how to apply air quality models to generate the predictions used to evaluate attainment and/or to set RPGs for regional haze. Modeling to show attainment of the NAAQS primarily applies to nonattainment areas² for which modeling is required, or desired. Modeling to assess reasonable progress for regional haze applies to all states, the District of Columbia, and the U.S. Virgin Islands.³

This guidance is designed to implement national policy on air quality modeling requirements as embodied in the Clean Air Act (CAA), the Ozone SIP Requirements Rule⁴, the $PM_{2.5}$ SIP Requirements Rule⁵, and the Regional Haze Rule⁶. In addition, the United States Environmental Protection Agency (EPA) revised 40 CFR part 51, Appendix W (Guideline on Air Quality Models) (U.S. EPA, 2017a), hereafter referred to as “Appendix W,” in 2017 to provide general information about the types of model approaches that may be appropriate for the purposes of demonstrating attainment with the ozone and $PM_{2.5}$ NAAQS (section 5) and projecting visibility impacts at Class I areas (section 6). Appendix W is a regulation and, as such, contains binding requirements. However, the Appendix W photochemical modeling requirements related to SIP

¹ Modeling to determine RPGs as described in this document is part of the development of a regional haze SIP. However, unlike the NAAQS, the Regional Haze program does not involve fixed air quality standards that must be achieved. The ways that RPGs are used in the development of a regional haze SIP are described in more detail in section 5.

² While this guidance document is primarily directed at modeling applications in nonattainment areas, it may also be useful as a guide for modeling to support NEPA analyses, maintenance plans or to support other rules or provisions of the Clean Air Act.

³ See 40 CFR 51.300(b).

⁴ See Implementation of the 2015 National Ambient Air Quality Standards for Ozone: Nonattainment Area State Implementation Plan Requirements; [Final rule signed November 7, 2018]

⁵ See Fine Particulate Matter National Ambient Air Quality Standards: State Implementation Plan Requirements ($PM_{2.5}$ SIP Requirements Rule), 81 FR 58101 (Aug. 24, 2016).

⁶ The Regional Haze Rule was revised by a final rule published on January 10, 2017 (82 FR 3078). This version of the modeling guidance reflects that revision of the rule. Additional revisions may be made to this guidance to be consistent with any future regional haze rule and/or guidance issued by EPA.

attainment demonstration modeling and regional haze modeling do not proscribe any particular models or modeling techniques. As such, this modeling guidance provides additional details about how to set up and run photochemical models that may be useful to air agencies that are required to submit SIP attainment demonstrations and/or regional haze modeling.

This guidance is intended for use by the EPA headquarters and Regional offices; federal land managers of mandatory Class I federal areas; state, local and tribal air quality management authorities, and the general public. This document does not substitute for provisions or regulations of the CAA enumerated above, nor is it a regulation itself. As the term “guidance” suggests, it provides recommendations on how to implement the modeling requirements. Thus, it does not impose binding, enforceable requirements on any party, nor does it assure that the EPA will approve all instances of its application, as the guidance may not apply to a particular situation based upon the circumstances.

The EPA and state, local, and tribal air agencies (hereinafter referred simply as “air agency” or “air agencies”) retain the discretion to adopt approaches on a case-by-case basis that differ from this guidance where appropriate. Final decisions by the EPA regarding a particular SIP submission that includes a modeling demonstration will ultimately be made based on the statute and applicable regulations and will only be made following a final submission by air agencies and after notice and opportunity for public review and comment. Interested parties are free to raise questions and objections about the appropriateness of the application of this guidance to a particular situation; the EPA and air agencies should consider whether or not the recommendations in this guidance are appropriate in that situation.

1.1 What Is the Purpose of This Document?

This document has two purposes. The first purpose is to describe how to apply an air quality model to produce results needed to support an attainment demonstration or to calculate RPGs for a regional haze reasonable progress analysis in a scientifically appropriate manner. The second is to explain how to interpret whether results of modeling and other analyses support a conclusion that attainment of the ozone and/or PM_{2.5} NAAQS will occur by the appropriate date for an area, and/or to assess progress towards the national visibility goal of the regional haze program.

1.2 Does the Guidance in This Document Apply to Me?

This guidance applies to all air agencies that are required to submit a State Implementation Plan (SIP), or Tribal Implementation Plan (TIP) submission with an attainment plan designed to

achieve attainment of the ozone and/or PM_{2.5} NAAQS. The guidance also applies to air agency SIP submissions developed to address Regional Haze Rule requirements. Air agencies required to submit an attainment demonstration and/or a reasonable progress analysis for regional haze are encouraged to follow the procedures described in this document. Details on when a state is required to submit a modeled attainment demonstration can be found in the Ozone SIP Requirements Rule⁷ and the PM_{2.5} SIP Requirements Rule⁸. Details on when a state is required to submit a regional haze SIP that includes RPGs can be found in the Regional Haze Rule⁹.

1.3 Outline

Part 1 of this guidance provides an overview of the modeling and attainment demonstration process. Part 2 describes how to build a “modeling platform” and apply air quality models. A “modeling platform” consists of the building blocks of an air quality modeling demonstration. This includes emissions modeling¹⁰, meteorological modeling, and the development of all other inputs needed to run an air quality model. The model platform development process consists of the following steps as outlined in section 2:

Section 2.1	Development of a conceptual description of the problem to be addressed
Section 2.2	Develop a modeling protocol
Section 2.3	Select appropriate meteorological time periods to model
Section 2.4	Choose an appropriate area to model with appropriate horizontal/vertical resolution
Section 2.5	Select an appropriate model to support the demonstration
Section 2.6	Generate meteorological inputs to the air quality model
Section 2.7	Generate emissions inputs to the air quality model
Section 2.8	Develop initial and lateral boundary conditions that are suitable for the application

Typically, the air quality modeling process starts with the development of base year emissions and meteorology for input to an air quality model to evaluate model performance. Section 3

⁷ See 40 CFR 51.1308.

⁸ See 40 CFR 51.1011.

⁹ See 40 CFR 51.308. Sections 308(d) and (e) apply for SIPs for the first implementation period only. States that followed section 51.309 (which is also part of the Regional Haze Rule) in the first implementation period were not required to develop RPGs. Section 51.308(f) applies to all Regional Haze SIPs due in 2021 and later.

¹⁰ Additional emissions inventory requirements and details on emissions modeling are contained in [“Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards \(NAAQS\) and Regional Haze Regulations.”](#)

describes the process for evaluating model performance and performing diagnostic analyses. After evaluating the model and making any necessary input changes or adjustments, the model is run for a future year, which corresponds to the appropriate attainment year for the area or to the future year modeled for regional haze planning purposes. Sections 2 and 3 apply to both ozone and PM_{2.5} modeling and modeling to set RPGs for regional haze SIPs.

Section 4 describes how the air quality model outputs are then used to apply the modeled attainment test to support an attainment demonstration for ozone or PM_{2.5}. We explain what is meant by a *modeled attainment demonstration*, a *modeled attainment test*, and a *weight of evidence demonstration*. Modeled attainment tests are described for the 8-hr ozone NAAQS and the annual and 24-hour PM_{2.5} NAAQS. Section 5 addresses aspects of modeling specific to regional haze SIPs.

Model applications require a substantial effort. Air agencies are encouraged to work closely with the appropriate EPA Regional office(s) in executing each step of the modeling and attainment demonstration or regional haze planning process. This will increase the likelihood of approval of the demonstration at the end of the process.

2.0 Building a Model Platform

2.1 Conceptual Description

The first step in developing an attainment demonstration is to construct a conceptual description of the problem that is being addressed. Conceptual descriptions, which are also referred to as conceptual models, are comprehensive summaries of the “state of the knowledge” regarding the influence of emissions, meteorology, transport, and other relevant atmospheric processes on air quality in the area (Vickery, 2004). For a conceptual description to be informative, it should identify what processes and sources, in the generic sense, are most responsible for the air quality issue being simulated. Well-constructed conceptual models can substantially inform the design of the attainment demonstration modeling (e.g., episode selection, choice of domain, emissions priorities, evaluation focus) and should be conducted in advance of the development of a modeling protocol. It is worth noting that conceptual descriptions can be valuable in other air quality planning efforts besides attainment demonstrations, such as determining nonattainment area boundaries, investigating emissions control program impacts, interstate transport analyses, and monitoring network design, among others.

The following bullets describe some of the key building blocks in developing a conceptual model. The process steps discussed below are meant to illustrate one possible template for building a conceptual model to inform an air quality modeling demonstration; there may be alternate approaches that better suit individual study areas or issues, which air agencies should discuss with the appropriate EPA Regional office.

- Introduce the general nature of the air quality problem addressed by the conceptual model:
 - What are the pollutants of concern in the area?
 - What are the current air quality levels in the area?
 - What is the attainment/nonattainment status of the area?
 - What is the geographical scope of poor air quality?
 - What is the temporal scope of poor air quality?
 - What are the air quality trends in the area? Is the problem getting better or worse?
 - What are the suspected mechanisms for formation of poor air quality levels?
 - What are the sources of emissions that may contribute to poor air quality?
 - Are there unique meteorological influences on local air quality levels?
- Describe the ambient monitoring network used for the conceptual model:
 - Develop a map of monitor sites and types (e.g., FRM, FEM, CSN, IMPROVE, CASTNET, etc.).

- Describe characteristics of individual monitoring sites (scale, frequency, etc.).
- Describe the status and trends of air quality in the area:
 - Summarize the relevant monitoring data for the air quality problem being studied.
 - Identify locations that are in violation of the NAAQS.
 - Describe the spatial pattern in pollutant and precursor pollutant levels.
 - Describe the temporal pattern in pollutant and precursor pollutant levels.
 - Describe the annual trends in concentrations over the period of interest.
 - If appropriate, develop fused ambient/model surfaces to fill any gaps within the monitoring network.
- Investigate possible relationships between emissions and air quality:
 - Examine emissions estimates for the main sector/source categories.
 - Compare emission trends for annual and or seasonal/episodic periods to corresponding air quality trends.
 - Identify key emission sources or source categories.
 - Assess the historical effectiveness of control programs.
 - Consider how future emissions growth or reductions may affect air quality.
 - List control programs that are in place, or will soon be implemented, that may impact emissions sources in the area.
- Investigate possible relationships between meteorology and air quality (AQ):
 - Describe meteorological characteristics on poor air quality days (e.g., wind speed/direction, temperatures, relative humidity levels, inversion indicators, etc.).
 - Identify any distinct meteorological phenomena that coincide with poor air quality days.
 - Prepare pollution roses, HYSPLIT back-trajectories (Draxler, 1998), or any other relevant analysis needed to link poor air quality days to specific meteorological patterns and sources of transported pollutants.
 - Assess the impact from pollutant transport into area based on meteorological data and ambient air quality data.
- Synthesize all the relevant information into a detailed conceptual model:
 - Aggregate all elements of the conceptual model and provide the key findings resulting from the analyses completed.
 - Characterize the potential factors that influence air quality in the area and where possible rank the importance of those influences.

- Identify issues that require further investigation, either in terms of data collection or chemical transport modeling.
- Discuss how the subsequent SIP modeling and associated protocol is impacted by this conceptual description.

2.1.1 Example Applications of Conceptual Models

The idea of developing a modeling protocol based upon a conceptual description of the sources and processes that lead to poor air quality is well-established (U.S. EPA, 2007a). Numerous excellent conceptual models of local and regional air quality issues have been developed over the past decade. Table 2-1 provides a non-comprehensive list of example conceptual models that have been developed since the last release of the guidance that may be useful in orienting future SIP modeling applications.

Table 2.1 Examples of recently developed conceptual models

Air quality issue	Reference
PM _{2.5} / Regional Haze (Northeast U.S.)	MANE-VU (2013)
PM _{2.5} (Midwest U.S.)	Lake Michigan Air Directors Consortium (LADCO) (2009)
Ozone (Austin TX)	McGaughey <i>et al.</i> (2010)
Ozone (Wyoming)	Stoeckenius (2010)
PM _{2.5} (Southeast Michigan)	Turner (2008)

2.2 Modeling Protocol and Supporting Documentation

As with any technical support document designed to inform air quality planning, an attainment demonstration or regional haze analysis should be supported by documentation that sufficiently describes the procedures used in the analysis. In order to facilitate the process of EPA Regional office review and approval, we recommend the preparation of two separate supporting documents for ozone and PM_{2.5} SIPs: one before the modeling analyses are initiated (modeling protocol) and one after the analyses have been completed (attainment demonstration package). We recommend a similar approach during the development of regional haze SIPs.

2.2.1 Modeling Protocol

Developing and implementing a modeling protocol is an important part of a modeling demonstration. The protocol should detail and formalize the procedures for conducting all

phases of the modeling study, such as describing the background and objectives for the study, creating a schedule and organizational structure for the study, selection of appropriate period(s) for modeling, developing the input data, conducting model performance evaluations, interpreting modeling results, describing procedures for using the model to demonstrate whether proposed strategies are sufficient to attain the NAAQS and/or regional haze goals, and producing documentation to be submitted for EPA Regional office review and approval. The most important function of the modeling protocol is to serve as a blueprint for planning how the modeled demonstration will be performed. The protocol should be a valuable communication device by which air agencies, EPA, and other stakeholders can assess the applicability of default recommendations and develop area-specific alternatives, where needed, prior to conducting the work to build the modeling system. A suitable protocol should lead to extensive participation by stakeholders in developing the demonstration. It should also reduce the risk of spending time and resources on efforts that are unproductive or inconsistent with EPA rules, policy, and guidance. While the modeling protocol is initially developed at the beginning of a modeling exercise to foster communication, it is advisable to modify the document as needed throughout the modeling process when alterations from the original modeling plan are necessary. Again, any changes to the protocol should be fully communicated between affected air agencies, stakeholders, and the EPA.

Meaningful protocols should fully communicate the expected scope of the analysis and provide a blueprint for carrying out the needed analyses. There is no “one-size-fits-all” format for a sufficient modeling protocol, as different individual areas may require specific points of emphasis. However, past attainment demonstrations have yielded several excellent protocol examples that could serve as templates for any groups developing new modeling protocols. While not exhaustive, potentially valuable protocol references include attainment demonstration modeling efforts completed in the Dallas/Fort Worth area (Environ, 2003), the Denver region (Morris, 2011), and the San Joaquin Valley (CARB, 2012). Based on past experience, the EPA recommends that the following topics be core elements of any modeling protocol:

- Overview of the air quality issue being considered including historical background
- List of the planned participants in the analysis and their expected roles
- Schedule for completion of key steps in the analysis and final documentation
- Description of the conceptual model for the area
- Description of periods to be modeled, how they comport with the conceptual model, and why they are sufficient
- Models to be used in the demonstration and why they are appropriate
- Description of model inputs and their expected sources (e.g., emissions, meteorology, etc.)

- Description and justification of the domain to be modeled (expanse and resolution)
- Process for evaluating base year model performance (meteorology, emissions, and air quality) and demonstrating that the model is an appropriate tool for the intended use
- Description of the future years to be modeled and how projection inputs will be prepared
- Description of the NAAQS attainment test procedures and (if known) planned weight of evidence, and/or description of the procedures for calculating RPGs from the modeling outputs, as applicable.
- Expected diagnostic or supplemental analyses needed to develop weight of evidence analyses
- Commitment to specific deliverables fully documenting the completed analysis

2.2.2 Attainment Demonstration and/or Reasonable Progress Goals Modeling Documentation Package

Whereas the modeling protocol describes the planned scope of the analysis, the final modeling documentation package summarizes the actual analysis conducted (including procedures used) to show that an area will likely meet the NAAQS and/or RPGs under a specific set of future conditions. This document can follow the same basic outline as the modeling protocol, highlighting those aspects of the modeling that may have changed from the original plans. Additionally, the modeling documentation package should have detailed information on any emission reduction strategies that will be implemented as part of an attainment or regional haze SIP. Ultimately, the modeling documentation package should provide a narrative that fully describes the technical rationale behind the projection of a specific air quality goal in an area. Based on past experience, the EPA recommends that the following topics be core elements of any modeling documentation package:

- Executive summary that provides an overview of the analysis and the key conclusions
- Reference to the modeling protocol noting any major deviations from the original plans
- List of the institutional participants in the attainment demonstration and their roles
- Description of air quality in the area and describe how that shaped the analysis
- Justification for the model, episodes, domain, and grid(s) used in the analysis
- Description of the development of the emissions inputs used in the base year modeling, including, at a minimum, tabular summaries by state/county, as appropriate

- Description of the development of meteorological inputs used in the base year modeling
- Description of all other base year modeling inputs
- Evaluation of base year model performance (meteorology, emissions, and air quality), including a description of the observational database used in the evaluation and any diagnostic or sensitivity tests used to improve the model
- Description of the strategy used to demonstrate attainment and/or RPGs, including speciated emissions summaries for the future year and identification of authority for implementing these strategies
- Description of the attainment test inputs and results
- Description of any supplemental analyses designed to bolster the original attainment test results
- Detailed summary of the entire analysis that leads to the conclusion that the selected attainment demonstration strategy is likely to produce attainment of the NAAQS by the required date and/or leads to the calculation of the RPGs
- Appendices that contain more detailed information on the model inputs and outputs (emissions, meteorology, etc.), model performance, and attainment demonstration, including charts, tables, and descriptive text

All model input and output files (in electronic format) should be made available upon request by the EPA and/or stakeholders.

2.3 Episode Selection

The modeled attainment test and the recommended procedure for setting RPGs for regional haze both adjust observed ambient concentrations during a base case period (e.g., 2012-2016) to a future period (e.g., 2023) using model-derived “relative response factors” (RRFs). It is important that emissions used in the attainment modeling correspond with the period reflected by the chosen baseline design value period (e.g., 2012-2016).¹¹ Deviations from this constraint will diminish the credibility of the RRFs. The base year modeling inventory typically corresponds to the middle year of the baseline average design value period (e.g. 2014 for a 2012-2016 average design value period). Alternatively, the base year emissions can reflect multi-year average emissions from the base year period (e.g. average emissions for the 2013-2015 period). But in

¹¹ The regional haze program does not use design values. However, in an analogous approach, this guidance recommends the use of 5 years of historical visibility data (non-weighted) in a manner similar to the approach in the modeled attainment test for ozone and PM_{2.5}. For this reason and for brevity, sections 2 and 3 use the “design value” terminology in some explanations that apply to both ozone and PM_{2.5} attainment modeling and to the setting of regional haze RPGs. That is, for regional haze purposes, “design values” can be understood to mean “visibility data.”

either case, the emissions year or years should be representative of the 5-year design value window.

There is no recommended default base year for modeling. However, it is recommended to use a relatively recent base period so that the emissions projection period is as short as possible and the base year ambient data is as current as possible. For example, projecting emissions from 2014 to 2023 (using a 2012-2016 base year average design value) should be less uncertain than projecting emissions from 2005 to 2023 (using a 2003-2007 base year average design value). The most recent ambient design values reflect actual emissions changes that have occurred over time. It is, therefore, better to use recent design values, which are actual measurements, combined with modeled emissions changes to project future concentrations, then to use older ambient data to estimate the change in design values. When selecting a base modeling year, air agencies should review recent ambient data and consider the factors in the following section.

2.3.1 Choosing Time Periods to Model

In the past, the choice of modeled episode days has been limited by the speed of computers and the ability to store model output files. With the advancement in computer technology over the past two decades, computer speed and storage issues are no longer an impediment to modeling long time periods. In fact, the majority of recent regulatory assessment modeling platforms have been inclusive of entire summers and/or full years (as appropriate) for ozone, PM_{2.5}, and regional haze (Boylan and Russell, 2006; Morris et al., 2006; Rodriguez et al., 2009; Simon et al., 2012; Tesche et al., 2006; U.S. EPA, 2011a, 2011b, 2016a).

Ozone-based research has shown that model performance evaluations and the response to emissions controls need to consider modeling results from relatively long time periods, in particular, full synoptic cycles or even full ozone seasons (Hogrefe et al., 2000; Vizuite et al., 2011). In order to examine the response to ozone control strategies, it may not be necessary to model a full ozone season (or seasons), but, at a minimum, modeling “longer” episodes that encompass full synoptic cycles is advisable. Time periods which include a ramp-up to a high ozone period and a ramp-down to cleaner conditions allow for a more complete evaluation of model performance under a variety of meteorological conditions.

Most model applications for the annual PM_{2.5} NAAQS have modeled a full year (Morris et al., 2006; Tesche et al., 2006; U.S. EPA, 2011a, 2011b, 2017b). This is a logical goal since every monitored day of the year is included in the calculation of the annual NAAQS. The annual PM_{2.5} NAAQS is unique because each and every ambient observation is included in the average. It is,

therefore, likely that a full year of modeled data is needed to adequately represent the annual average PM_{2.5} NAAQS.

Eight-hour ozone and 24-hour PM_{2.5} episode selection criteria are similar because both standards are based on short-term peak concentration periods. Regional haze calculations are based on an average of 20 or more days per year (20% clearest and 20% most impaired days). Therefore, regional haze episode selection will likely include more days throughout the year.

At a minimum, several criteria should be used to select time periods that are appropriate to model:

- Model time periods that are close to the most recently compiled and quality assured National Emission Inventory (NEI). These comprehensive inventories are typically generated every 3 years (e.g. 2011, 2014, 2017, etc.), but often contain year-specific data for the intermediate years. Since NEI years will have a nationwide complete and comprehensive inventory, selecting a base modeling year that is also an NEI year may save resources. However, other factors should be considered when selecting a base modeling year, such as the availability and magnitude of observed ambient data, meteorology, and availability of special study data. After consideration of all factors, the most appropriate base year may or may not be an NEI year. See section 2.7 for more information on base year inventory selection issues.
- Model time periods in which observed concentrations are close to the appropriate base year design value or level of visibility impairment and ensure there are a sufficient number of days so that the modeled test applied at each monitor is based on multiple days.
- Model time periods both before and following elevated pollution concentration (poor air quality) 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.
- Simulate a variety of meteorological conditions conducive to elevated/poor air quality.

Primary Ozone (8-Hour Ozone) - Choose time periods which reflect a variety of meteorological conditions that frequently correspond with observed 8-hour daily maxima concentrations greater than the level of the NAAQS at monitoring sites in the nonattainment area.

24-Hour PM_{2.5} - Choose time periods that reflect a variety of meteorological conditions that frequently correspond with observed 24-hour average concentrations greater than the level of the NAAQS at monitoring sites in the nonattainment area.
Annual PM_{2.5} - The best way to represent the meteorological variability within a season and over an entire year is to model an entire year that has meteorology generally conducive to elevated PM _{2.5} concentrations.
Regional Haze - Choose time periods that reflect the variety of meteorological conditions that represent visibility impairment on the 20% clearest and 20% most impaired days in the Class I areas being modeled (high and low concentrations necessary). This is best accomplished by modeling a full year.
Long-term or seasonal ozone – Since long-term (seasonal) ozone assessments are based on accumulated ozone over multiple months during the ozone season, the most appropriate way to represent the variability in high and low ozone is to model an entire ozone season that is representative of long-term values. [Note: This analysis is only applicable if seasonal ozone assessments are necessary (e.g. to support ozone benefits calculations). Currently, there are no long-term or seasonal ozone NAAQS (primary or secondary).]

2.3.2 Future Year Selection

For ozone and PM_{2.5}, future emissions should be projected to the attainment year or appropriate time period based on the area's classification. The Ozone SIP Requirements Rule provides a schedule for implementing emission reductions needed to ensure attainment by the area's attainment date. Specifically, it states that emission reductions needed for attainment must be implemented no later than the beginning of the attainment year ozone season.¹² The PM_{2.5} Implementation Rule contains similar provisions. It states that emissions reductions should be in place no later than the beginning of the year containing the applicable attainment date.¹³

As part of demonstrating attainment of the ozone and PM_{2.5} NAAQS, air agencies are required to conduct a Reasonably Available Control Measures (RACM) analysis to determine if the attainment date can be advanced by at least a year. Since areas are required to attain as expeditiously as practicable, results of the RACM analysis may indicate attainment can be achieved earlier.

¹² See 40 CFR 51.1308(d).

¹³ See 40 CFR 51.1011(a)(5) and 40 CFR 51.1011(b)(5).

There are varying requirements related to attainment year and RACM analyses for ozone and PM_{2.5} nonattainment areas, depending on classifications and other factors. Please see the appropriate ozone and/or PM_{2.5} implementation rule for more details and information.¹⁴

For regional haze SIPs, RPGs must reflect the visibility conditions that are projected to be achieved by the end of the applicable implementation period.¹⁵ Therefore, the modeling should be based on emissions forecasted for the end year of the implementation period addressed by the SIP. These end years are 2018, 2028, etc.

2.4 Modeling Domain Selection

A modeling domain identifies the geographical bounds of the area to be modeled. Horizontal resolution is the geographic size of individual grid cells within the modeling domain. Vertical resolution is specified in terms of multiple layers of the atmosphere between the surface and top of the model (usually near the tropopause).

2.4.1 Domain Size

The principal determinants of model domain size are the nature of the ozone, PM_{2.5} and/or regional haze problem being modeled, and the spatial scale of the emissions that impact the nonattainment or Class I area. Establishment of a sufficiently large model domain that utilizes the output from a larger regional or global modeling simulation to feed hourly lateral boundary conditions is a preferred approach (see section 2.8 for more information on boundary conditions). However, regardless of the size of the modeling domain, sources outside the modeling domain may have an important influence on concentrations within nonattainment areas or Class I areas. Therefore, boundary conditions need to be well characterized. The grid containing the key emissions sources and receptors needs to have sufficiently fine-scale to resolve local gradients and have a large enough spatial extent to capture recirculation due to shifting wind directions. An alternative to a single large domain to capture recirculation is to apply a chemical transport model with a large coarse domain with a smaller-domain, nested fine grid with feedback between the grids (i.e., 2-way nesting). This option allows pollutants from the fine grid to move into the coarser domain and back into the fine grid depending on wind patterns.

Global models are routinely used to supply regional chemical transport models with temporally and spatially variant lateral boundary conditions. Since regional and urban model applications

¹⁴ See 40 CFR 51.1009 (moderate PM_{2.5}), 40 CFR 51.1010 (serious PM_{2.5}) and 40 CFR 51.1312 (ozone).

¹⁵ See 40 CFR 51.308(f)(3)(i).

for attainment demonstration purposes are typically less than or equal to 12 km sized grid cells, it may be worthwhile to apply the regional scale model at a coarser grid resolution (e.g. 36 km) to downscale global model estimates to the regional model. The coarser simulation results provide a better transition from the global simulation to the nested urban or urban/regional area of interest both at the boundaries near the surface and in the free troposphere. See section 2.8 for more information on using global and/or regional models to derive initial and lateral boundary conditions.

Isolated nonattainment areas that have limited impacts from regional transport of ozone and/or PM_{2.5} and its precursors may be able to use a relatively small domain. The modeling domain should be designed so that all major upwind source areas that influence the downwind nonattainment area are included in the modeling domain. It is also important to be able to directly capture the impact of future year emissions increases or decreases from upwind areas. In addition, all monitors that are currently or recently (within any of the years included in the base year period) violating the NAAQS or close to violating¹⁶ the NAAQS in the nonattainment area should be contained in the modeling domain far enough from the edge to minimize complications associated with air mass recirculation and to minimize lateral boundary influence. Similarly, all Class I areas to be evaluated in a regional haze modeling application should be sufficiently distant from the edge of the modeling domain.

2.4.2 Vertical Layer Configuration

There is no correct maximum or minimum number of vertical layers needed in attainment demonstration modeling. However, the specification of the air quality model vertical layer structure should closely match the vertical layer structure of the meteorological model used to generate inputs for the air quality model. It is best to have an air quality model's vertical layers align with the layers in the meteorological model matching one-to-one. However, resource constraints sometimes preclude direct vertical layer mapping. When vertical layer collapsing is necessary, use the highest resolution where the conceptual model suggests it is most needed.

The top of the modeling domain should typically be set above the tropopause at the 50 or 100 millibar level. The lowest layer (surface layer) in the air quality model should be no more than ~40 meters thick. The vertical resolution between the surface layer and model top will vary

¹⁶ A monitor that is "close to violating" the NAAQS in a base year may be modeled to violate in the future due to projected emissions increases or modeled "dis-benefits" due to non-linear chemistry. Air agencies should consult with the appropriate EPA Regional office if there are questions regarding the interpretation of "close to violating" and which monitors should be included in the modeling analysis.

depending on the application. Layer thickness should monotonically increase or be the same size as altitude increases.

In view of the importance of carefully specifying the temporal variation in mixing height, high precision below and near the anticipated maximum afternoon mixing height is ideal. In addition, near-surface vertical resolution is important to capture overnight stable conditions. Layers above the boundary layer are important for characterizing clouds and precipitation and layers near the tropopause are important to create a realistic stratification of strongly variant pollutant concentrations in the stratosphere and free troposphere (Emery et al., 2011).

There are some model applications that may not need to consider the full extent of the troposphere. These applications typically use vertical domains, which extend up to 4 or 5 km. These types of applications may cover episodes of elevated pollutant concentrations associated with strong surface-based inversions that occur in isolated areas. However, in almost all cases, the EPA encourages the use of full-scale one-atmosphere models that account for all atmospheric processes throughout the extent of the troposphere.

2.4.3 Horizontal Grid Cell Size

Recent chemical transport modeling applications for ozone, PM_{2.5}, and regional haze have commonly used grid cell sizes ranging from 4 km to 12 km resolution (Morris et al., 2006; Rodriguez et al., 2009; Simon et al., 2012; U.S. EPA, 2011b, 2016a; Vizuite et al., 2010). Urban scale assessments have used chemical transport grid models at 1 to 2 km resolution (Vizuite et al., 2011). Intuitively, one would expect to get more accurate results in urban applications with smaller grid cells (e.g., ~1 or 4 km) provided the spatial details in the emissions and meteorological inputs support making such predictions. However, model performance at 4 km resolution is not always better than 12 km resolution (Simon et al., 2012).

For coarse portions of the regional grids, a grid cell size of 12 km is generally recommended. For urban areas, it may be desirable to use grid cells sized ~1 to 4 km, but not larger than 12 km. The relative importance of using a domain with grid cells as small as ~1 km should be weighed on a case-by-case basis. If the conceptual model indicates that there are atmospheric, physical, or chemical processes related to the air quality issue that require a specific minimum resolution to simulate (e.g., localized emissions, complex terrain, land-water interfaces, etc.), then that resolution should be utilized in the model. For example, it is likely that spatial gradients in concentrations are higher for primary pollutants (e.g., primary particulate matter, or PM) than for secondary pollutants because physical processes dominate concentration rather than chemical processes. Although it is clear that spatial resolution of primary pollutants will impact

the predicted concentrations, it is not clear how it will impact the relative change in concentrations due to emissions changes. Areas that have large gradients in primary PM_{2.5} may need to use finer resolution (approximately ~1 to 4 km) or may need to supplement the grid modeling with dispersion modeling. This is particularly true if violating monitors are strongly impacted by local sources of primary PM_{2.5} emissions.

The most important factor to consider when establishing grid cell size is model response to emissions controls. Analysis of ambient data, sensitivity modeling, and past modeling results can be used to evaluate the expected response to emissions controls at various horizontal resolutions for ozone, PM_{2.5}, and regional haze. If model response is expected to be different (and presumably more accurate) at higher resolution, then higher resolution modeling should be considered. If model response is expected to be similar at both high and low(er) resolution, then high resolution modeling may not be necessary. The use of grid resolution finer than 12 km would generally be more appropriate for areas with a combination of complex meteorology, strong gradients in emissions sources, and/or land-water interfaces in or near the nonattainment area(s).

Sensitivity tests comparing relative response factors in predicted 8-hour daily maximum ozone at sites in the eastern United States indicate relatively small unbiased differences (< 4%, in RRF difference in 95% of the comparisons) using a grid with 12 km versus 4 km sized grid cells (Arunachalam, 2006). The largest difference in the relative response of secondary pollutants at varying resolution is likely to occur in oxidant limited areas (areas that are more sensitive to VOC reductions than NO_x reductions). In such areas, horizontal resolution may have a large impact on the spatial distribution and magnitude of modeled NO_x “disbenefits” (i.e., ozone increases in oxidant limited areas when NO_x emissions are reduced).

2.5 Air Quality Model Selection

Chemical transport models address the physical processes and chemistry that form ozone and PM. Air quality models continue to evolve and each has its own strengths and weakness (Galmarini et al., 2012; Pirovano et al., 2012; Russell, 2008; Simon et al., 2012). The most commonly used chemical transport models for attainment demonstrations are the Community Multiscale Air Quality Model ([CMAQ](#)) (Byun and Schere, 2006; Foley et al., 2010) and the Comprehensive Air Quality Model with Extensions ([CAMx](#)) (Baker and Scheff, 2007; Vizuite et al., 2011). The mention of CMAQ and CAMx is not intended to be a comprehensive list of available chemical transport models and omission from this discussion does not imply that a different model cannot be used to support a modeled attainment demonstration or reasonable

progress assessment. In the same way, inclusion in this discussion does not imply that a model is “preferred” for a particular type of application.

A modeling-based demonstration of the impacts of an emissions control scenario for attainment of the ozone or PM_{2.5} NAAQS, or as part of a regional haze assessment, usually necessitates the application of a chemical transport grid model. However, it is not necessary to use a model that considers atmospheric chemistry in addressing changes in primary PM_{2.5} components. Either a numerical grid or a Lagrangian (such as a Gaussian dispersion) model or other empirical techniques could potentially be used for this purpose. In general, modeling primary PM_{2.5} components with a grid model is acceptable, but dispersion modeling may be necessary in areas with large spatial gradients of primary PM_{2.5}. Depending on the nature of the problem, an air agency may choose to use a regional chemical transport grid model to address both primary and secondary components of PM or they may need to use a chemical transport model to address secondary PM_{2.5} and regional primary PM and an inert model applied over a more limited domain to address fine scale primary components of PM. In addition, the EPA recognizes that in some cases, more simplistic modeling techniques (such as dispersion, receptor, rollback, and/or box models) may suffice to demonstrate that an area will attain the PM_{2.5} NAAQS, especially in areas that are dominated by primary PM_{2.5} emissions (e.g., residential wood smoke).

A model should meet several general criteria in order to be considered for use in an attainment demonstration or reasonable progress assessment. These general criteria are consistent with requirements in Appendix W (U.S. EPA, 2017a). Appendix W does not identify a “preferred model” for use in attainment demonstrations of the NAAQS for ozone or PM_{2.5} or reasonable progress assessments for regional haze. Therefore, at this time, the EPA is not recommending a specific model for use in ozone or PM_{2.5} attainment demonstrations or regional haze uniform rate of progress assessments. Instead, models used for these purposes should meet requirements for “alternative models” in Appendix W, section 3.2. Air agencies should use a non-proprietary model, which is a model whose source code is available for free (or for a reasonable cost). Furthermore, the user should be able to revise the source code to perform diagnostic analyses and/or to improve the model’s ability to describe observations in a credible manner. Several additional prerequisites should be met for a model to be used to support an attainment demonstration or reasonable progress assessment (see Appendix W, section 3.2.2(e), as well as sections 5 and 6 for more general secondary pollutant modeling requirements):

- 1) The model or technique has received a scientific peer review.

An air quality model may be considered to have undergone “scientific peer review” if each of the major components of the modeling system has been

described and tested, and the results have been documented and reviewed by one or more disinterested third parties, and the model has been revised in response to the review. This review is not the responsibility of the EPA. Air agencies should reference available documentation to gain acceptance of an air quality model for use in a modeled attainment demonstration.

- 2) The model or technique can be demonstrated to be applicable to the problem on a theoretical basis.
 - The model should be scientifically appropriate and applicable for the intended purpose.
- 3) Databases, which are necessary to perform the analysis, are available and adequate.
- 4) Appropriate performance evaluations of the model or technique have shown that the model or technique is not inappropriately biased for regulatory application.
 - Prior to use of a selected model's results in an attainment demonstration or regional haze analysis, the model should be shown to perform adequately for the specific application.
 - If the application is the first for a particular model, then the air agency should demonstrate that the new model is expected to perform sufficiently. For a model to be used in an attainment demonstration, evidence should be presented that it has been found acceptable for estimating hourly and 8-hourly ozone concentrations and/or hourly and 24-hour average PM_{2.5} and PM_{2.5} component concentrations. In addition to ozone and/or PM_{2.5}, the model should be acceptable for estimating precursor species, important chemical intermediates, and in the case of PM_{2.5}, the main chemical constituents. Preference should be given to models exhibiting satisfactory past performance under a variety of conditions.
- 5) A protocol on methods and procedures to be followed has been established (such as described in section 2.2.1).

In addition to the criteria in Appendix W, the EPA also recommends the following criteria and considerations:

- 1) A user's guide (including a benchmark example and outputs) and technical description of the model should be available.

- 2) The advanced technical features available in a model could be a consideration when other criteria are satisfied. Models are often differentiated by their available advanced science features and tools. For example, some models include advanced probing tools that allow tracking of downwind impacts from upwind emissions sources. Availability of probing tools and/or science algorithms is a legitimate reason to choose one equally capable model over another.
- 3) When other criteria are satisfied, resource considerations may be important. This is a legitimate criterion provided the other listed criteria are met.

The EPA has prepared an “alternative model” [demonstration](#) for both CMAQ and CAMx for the purposes of supporting ozone or PM_{2.5} attainment demonstrations and regional haze assessments (Fox, 2017). This document is also a useful template for others seeking to provide a similar type of demonstration for another photochemical modeling system.

2.6 Meteorological Inputs

In order to solve for the pollutant concentrations over time and space, air quality models require accurate meteorological inputs to properly simulate the formation, transport, and removal of pollutant material. The required meteorological inputs can vary by air quality model, but all models require parameters such as wind, vertical mixing, temperature, humidity, and solar radiation. While model inputs can be created strictly from ambient measurements, a more credible technical approach is to use off-line, dynamic, meteorological grid models to provide the necessary inputs. When these models are applied retrospectively (i.e., for historical time periods), they are able to blend ambient data with model predictions via four-dimensional data assimilation (FDDA), thereby providing temporally and spatially complete data sets that are grounded by actual observations.

This section provides recommendations for generating the meteorological data sets needed for regional air quality modeling purposes. In many ways, the development of meteorological inputs parallels the steps needed to conduct the air quality modeling. A meteorological model platform (episodes, domain, model selection, model configuration, input data, etc.) must be established and then evaluated. Because of the strong sensitivity of the eventual air quality results to the input meteorology (Appel, 2007; Appel, 2010), it is recommended that air agencies spend extensive effort in developing and evaluating the meteorological inputs.

2.6.1 Developing Base Year Meteorological Fields

The recommended approach for generating the base year meteorological data needed to conduct the attainment or regional haze demonstration is to apply off-line, dynamic meteorological models with FDDA. These models use the fundamental equations of momentum, thermodynamics, and moisture to determine the evolution of specific meteorological variables from a given initial state. When modeling historic episodes, the use of data assimilation helps to "nudge" solutions so that they do not diverge greatly from the actual observed meteorological fields. A major benefit of using dynamic meteorological models is that they provide a way of consistently characterizing conditions at times and locations where observations do not exist.

The Weather Research and Forecasting (WRF) (Skamarock, 2008) model is a community supported mesoscale numerical prediction model that replaced the previous community supported mesoscale meteorological model v5 (MM5) model. The MM5 model is no longer being updated or supported. Meteorological models other than the WRF can be used as long as they are appropriate for the situation being modeled and are properly evaluated. A number of recent studies (Appel et al., 2010; de Meij et al., 2009; Gilliam et al., 2010; Matichuk et al., 2017; Pleim et al., 2016) have compared the ability of the WRF and MM5 models to reproduce past meteorological conditions and their suitability for use in air quality modeling. Generally speaking, comparative evaluation efforts have shown that the WRF model outputs represent equivalent or better statistical skill over a variety of meteorological conditions. An additional advantage of the WRF model is that there is a large community of WRF users and developers. As a result, the code is both maintained and frequently updated as new science emerges. The EPA recommends the use of a well-supported gridded mesoscale meteorological model for generating meteorological inputs to regional air quality model attainment demonstrations.

In some cases, however, there may be legitimate reasons for using an approach other than well-supported gridded mesoscale meteorological models to provide the requisite meteorological data. For instance, there may be long-standing local experience for a given domain and/or episode with a different meteorological model. In other cases, dynamic meteorological models may not adequately capture key meteorological elements of an airshed's conceptual model (e.g., source-receptor transport vectors to key monitoring locations). In rare cases such as these, it may be appropriate to blend the dynamic model data with wind data from an objective analysis of observed wind fields. The guiding factor in determining which meteorological model or approach to use should be an assessment of which set of inputs will best capture the key meteorological conditions that led to poor air quality. It is recommended that a description of the methods used to generate the meteorological fields be

included in the modeling protocol. For those cases in which an off-line prognostic meteorological model is not used, it is recommended that a detailed description of the alternate technique that will be used to generate the three-dimensional meteorological fields be shared with the appropriate EPA Regional office(s) prior to conducting the meteorological analysis and air quality modeling analysis.

As with other parts of the air quality modeling system, choices made regarding how to configure the meteorological modeling can affect the quality and suitability of the air quality model predictions. Decisions regarding the configuration of complex dynamic meteorological models can be particularly challenging because of the amount of flexibility available to the user. The goal in establishing the proper configuration for meteorological modeling should be to obtain the best possible meteorological model performance, especially for those parameters identified as most important in the conceptual description. As part of the overall chemical transport modeling system evaluation process, performance issues in the chemical transport model can sometimes be explained by options chosen in the meteorological simulation. Therefore, a feedback between the meteorological model evaluation and the air quality model evaluation can be highly beneficial.

2.6.1.1 Selecting a Model Domain

The selection of the meteorological modeling domain should closely match the air quality domain. The outermost grid should capture all upwind areas that can reasonably be expected to influence local concentrations of ozone and/or PM_{2.5}. In terms of selecting an appropriate meteorological modeling domain, one should extend the grid at least 3 to 6 cells beyond the domains of each air quality modeling grid to avoid boundary effects. It is recommended that the vertical and horizontal grid structures, including geographic datum and projected coordinate definitions, be generally consistent within the meteorological and air quality models to minimize interpolation and aggregation issues associated with the post-processing of meteorological model outputs into air quality model inputs.

2.6.1.2 Selecting Physics Options

Meteorological models have a suite of physics options that allow users to configure how a given meteorological effect will be simulated. For example, there may be several options for specifying the planetary boundary layer scheme or how sub-grid cumulus clouds will be handled. In many situations, the "optimal" configuration cannot be determined without performing an initial series of sensitivity tests, which consider various combinations of physics options over specific time periods and regions. While these tests may not ultimately conclude that any one configuration is clearly superior at all times and in all areas, it is recommended

that these sensitivity tests be completed, as they should lead to a modeling analysis that is best suited for the domain and period being simulated. An optimal starting point of physics options may be selected from another modeling application that has a similar set of meteorological conditions that lead to elevated pollutant levels. Typically, the model configuration that yields predictions that provide the best statistical match with observed data over the most cases (episodes, regions, etc.) is the one that should be chosen, although other more qualitative information can also be considered. Additionally, model configurations should be designed to account for the pollutants and time periods that are of most interest, per the conceptual description.

2.6.1.3 Use of Data Assimilation

As noted above, the use of FDDA helps to keep the model predictions from widely diverging from what was actually observed to occur at a particular point in time/space. Studies have shown that the incorporation of FDDA into atmospheric models improves meteorological simulations (Otte, 2008a and b; Pleim and Gilliam, 2009; Gilliam and Pleim, 2010). In particular, these studies have shown that better representation of the atmospheric fields aloft through assimilation of data from nationwide atmospheric profiler networks can aid in reproducing certain meteorological features (e.g., low-level jets) (Godowitch et al., 2011; Gilliam et al., 2012). However, if used improperly, FDDA can significantly degrade overall model performance and introduce computational artifacts (Tesche and McNally, 2001). Inappropriately strong nudging coefficients can distort the magnitude of the physical terms in the underlying atmospheric thermodynamic equations and result in "patchwork" meteorological fields with strong gradients between near-site grid cells and the remainder of the grid. Additionally, if specific meteorological features are expected to be important for predicting the location and amount of pollution formed, based on an area's conceptual model, then the meteorological modeling should be set up to ensure that FDDA does not prevent the model from forming these features (e.g., lake/sea breeze circulations).

In general, analysis nudging strengths should be no greater than 3.0×10^{-4} for winds and temperatures and 1.0×10^{-5} for water vapor mixing ratio. In the case of observation nudging (i.e., FDDA based on individual observations as opposed to analysis fields), it is recommended that the resultant meteorological fields be examined to ensure that the results over the entire domain are still consistent. Further, based on past experience, we recommend against using FDDA within the boundary layer for thermodynamic variables like temperature and water vapor mixing ratio because of the potential for spurious convection. If the dynamic model is applied without FDDA, it is suggested that the simulation durations be no longer than 24 hours. As with selecting physics options, it is often valuable to conduct sensitivity testing of various FDDA approaches to help determine the optimal nudging configuration for any specific case.

Along with application of the meteorological modeling, users should be careful when translating the meteorological model outputs into air quality modeling inputs. A number of air quality model pre-processors (which are meteorological model post-processors) exist to conduct this off-line coupling, including the Meteorology-Chemistry Interface Processor (MCIP) (Otte and Pleim, 2010) and wrfcamx (Ramboll-Environ, 2017). These meteorological post-processors generate the complete set of meteorological data needed for the air quality simulation by accounting for issues related to:

- 1) Data format translation;
- 2) Conversion of parameter units;
- 3) Extraction of data for appropriate window domains;
- 4) Reconstruction of the meteorological data on different grid and layer structures; and
- 5) Calculation of additional variables.

As noted above, most meteorological modeling applications should be set up to minimize the influence of the pre-processing software. For instance, it is recommended that the horizontal grid structures be consistent within the meteorological and air quality models to minimize issues associated with interpolation and aggregation. While it is often not feasible to run the air quality model with the same vertical layer structure as the meteorological model, it is recommended that vertical layer collapsing between the models be minimized (preferably with no layer collapsing), to the extent possible.

While the traditional approach for attainment and regional haze demonstration modeling is to convert “off-line” meteorological model outputs into air quality model inputs via specific pre-processing tools, there have been recent efforts to couple “on-line” meteorological models within air quality model applications, such as WRF-Chem (Grell et al., 2005; Wilczak et al., 2009), NOAA-EPA CMAQ (Davidson et al., 2007), and WRF-CMAQ (Wong et al., 2012). The advantage of an on-line meteorological model is that one can simulate impacts that air quality changes might have on meteorological conditions (and vice versa) through direct and indirect feedback mechanisms. In most cases, the EPA does not expect emissions reductions from local SIP reductions to appreciably affect future meteorological conditions. Therefore, off-line meteorological approaches, where the same meteorological fields are used for multiple emissions scenarios, are expected to be sufficient for the majority of SIP modeling exercises.

2.6.2 Assessing Impacts of Future Year Meteorology

Traditionally, SIP meteorology simulations have not accounted for the impact of global emissions of carbon dioxide and other climate forcers on future meteorological conditions. However, ozone concentrations have a high correlation with daily maximum temperatures over many areas in the U.S. (Camalier et al., 2007), suggestive of a potential climate connection.

Recent research, taking into account temperature and other meteorological variables, indicates that in certain populated regions of the country, climate change could lead to higher future ozone concentrations (often called a “climate penalty”) (Jacob and Winner, 2009; Bloomer et al., 2009; U.S. EPA, 2009; CARB 2010; Fiore, 2012; Fann, 2016). Assuming climate change does lead to higher ozone concentrations, there could potentially be a need for more stringent emissions reductions to counteract the higher ozone potential from warmer conditions. However, there are significant uncertainties regarding the precise location and timing of climate change impacts on air quality. Generally, climate projections are more robust for periods at least several decades in the future because the forcing mechanisms that drive near-term natural variability in climate patterns (e.g., El Nino, North American Oscillation) have substantially larger signals over short time spans than the driving forces related to long-term climate change. In contrast, projections for SIP purposes are generally for time spans of less than 20 years. Given the relatively short time span between base and future year meteorology in most SIP demonstrations, the EPA does not recommend that air agencies explicitly account for long-term climate change in attainment demonstrations. However, air agencies are welcome to consider potential climate impacts in their specific areas, especially where and when there is evidence of significant potential impacts.

2.6.3 Evaluation of Base Year Meteorological Fields

While the air quality models used in attainment and regional haze demonstrations have consistently been subjected to a rigorous performance assessment, in many cases the meteorological inputs to these models have received less rigorous evaluation, even though this component of the modeling is quite complex and has the potential to substantially affect air quality predictions (Tesche, 2002). The EPA recommends that air agencies devote appropriate effort to the process of evaluating the meteorological inputs to the air quality model as we believe good meteorological model performance will yield more confidence in predictions from the air quality model. One of the objectives of this evaluation should be to determine if the meteorological model output fields represent a reasonable approximation of the actual meteorology that occurred during the modeling period. Further, because it will never be possible to exactly simulate the actual meteorological fields at all points in space/time, a second objective of the evaluation should be to identify and quantify the existing biases and errors in the meteorological predictions in order to allow for a downstream assessment of how the air quality modeling results are affected by issues associated with the meteorological data. To address both objectives, it will be necessary to complete both an operational evaluation (i.e., quantitative, statistical, and graphical comparisons) as well as a more phenomenological assessment (i.e., generally qualitative comparisons of observed features versus their depiction in the model data).

2.6.3.1 Operational Evaluation

The operational evaluation results should focus on the values and distributions of specific meteorological parameters as paired with and compared to observed data. It is recommended that the observation-model matching be paired as closely as possible in space and time. Typical statistical comparisons of the key meteorological parameters will include: comparisons of the means, mean bias, normalized mean bias, mean absolute error, normalized mean error, and root mean square error. For modeling exercises over large domains and entire ozone seasons or years, it is recommended that the operational evaluation be broken into individual segments such as geographic subregions and/or months/seasons to allow for a more comprehensive assessment of the meteorological strengths and weaknesses. It may also be useful to break out model performance aloft, at the surface, during individual episodes (e.g., high ozone/PM_{2.5} days), over the diurnal cycle, and as a function of synoptic regime. Modelers are also encouraged to set aside a portion of the ambient data strictly for evaluation purposes (i.e., data not used in the FDDA). Examples of observed meteorological data sets available for operational evaluations include (some of these data sets are not typically used in FDDA and, therefore, may be serve as an “independent” source of evaluation data):

1. TDL U.S and Canada Surface Hourly Observations (<http://rda.ucar.edu/datasets/ds472.0>);
2. Cooperative Agency Profilers (<https://madis-data.noaa.gov/cap/>);
3. NOAA Profiler Network (<http://profiler.noaa.gov/npn/>);
4. Individual State Climate Office Observation Networks; and
5. PRISM Climate Group Precipitation Analysis (<http://www.prism.oregonstate.edu/>).

While these data are readily available, it is up to the air agency to determine if the data have undergone appropriate quality assurance/quality control (QA/QC) procedures through the provider.

It may be helpful when calculating domainwide and/or regional summary statistics to compare the results against previously generated meteorological model performance "benchmarks" (Emery et al., 2001). However, because of concerns about potentially misleading comparisons of model performance findings across different analyses with differing model configurations and FDDA strengths, the EPA does not recommend using these benchmarks as a "pass/fail" indicator of the acceptability of a model simulation. The benchmarks should only be used as a means of assessing general confidence in the meteorological model data. Statistical results that are outside the range of the compiled benchmarks may indicate a performance issue that should be given further examination. In some cases, adjustment of input data and/or model settings may be needed in order to improve model performance. The [Atmospheric Model](#)

[Evaluation Tool](#) (AMET) was designed for use in the assessment of meteorological and chemical transport models. AMET provides a method of pairing observed and simulated values and performing common analysis techniques to evaluate the performance and suitability of atmospheric models.

2.6.3.2 Phenomenological Evaluation

As discussed in section 2.1, it is recommended that a conceptual description of the area's air quality problem be developed prior to the initiation of any air modeling study. Within the conceptual description, it is recommended that the specific meteorological parameters that influence air quality be identified and qualitatively ranked in importance. When evaluating meteorological models or any other source of meteorological data, the focus of the phenomenological evaluation should be on those specific meteorological phenomena that are thought to strongly affect air pollution formation and transport within the geographic area of interest. This event-oriented evaluation should summarize model performance in terms of statistical metrics such as probability of detection and false alarm rate. As an example of a potential phenomenological analysis, many regional air quality modeling exercises attempt to assess the effects of transport of pollutants from one area to a downwind area with the intent of establishing source-receptor relationships. For these types of analyses, accurate transport wind trajectories are needed to properly establish these source-receptor linkages. A useful event-based meteorological evaluation would be to compare model-derived trajectories versus those based on ambient data to determine what error distance can be associated with the model fields. Other examples of phenomenological evaluations would be the replication by the model of low level nocturnal jets, cold pool conditions, fog events, or land/sea breezes.

2.7 How Are the Emission Inputs Developed?

Air quality modeling for 8-hour ozone, PM_{2.5}, and regional haze requires emissions data for a base year and future modeling years. While not explicitly a requirement of the implementation rules, the emissions data for modeling are a necessary input to the modeling that is required by the implementation rules as part of the modeled attainment demonstration and for regional haze analyses.

A separate EPA guidance document describes the planning inventories that are specifically required for SIPs and provides an overview of all emission inventory requirements, resources, and techniques. That guidance is the "[Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards \(NAAQS\) and Regional Haze Regulations](#)" (U.S. EPA, 2017b), and is used as a key reference throughout this section.

Many of the issues associated with the planning inventories are also relevant for modeling inventories. We will refer to that guidance here as the “EI SIP Guidance.”

Table 1 of the EI SIP Guidance provides a list of emissions estimation resources for emissions inventories. In addition to the resources listed there, the EPA also provides emissions data used in modeling analyses in support of rulemakings. The current available "emissions platforms" are based on 2005, 2007, 2008, 2011, and 2014 base years. These platforms are available publicly on the [Emissions Modeling Clearinghouse website](#). The emissions modeling data and other data included in these platforms can be a starting point for air agencies in developing their own capabilities for preparing emissions for use in air quality models.

2.7.1 What Emissions Inventory Years Should I use for Base and Future Modeling?

For the base year, the EPA does not require a particular modeling year for PM_{2.5} and ozone SIP attainment plans, and regional haze plans. However, for several reasons, it is technically appropriate to use a recent year as the base year. In addition, there are certain regulatory requirements for selecting an appropriate base year for planning inventories. See ozone NAAQS inventory requirements at 40 CFR 51.1315 and PM_{2.5} NAAQS inventory requirements at 40 CFR 51.1008.¹⁷ Currently, the most recent base National Emissions Inventory (NEI) is 2014 (U.S. EPA 2016c), and NEI data are developed every 3 years (the next NEI year will be 2017). In most cases, the most recent NEI year will be the most appropriate year to use for base case modeling. In some cases, other years (either before or after the most recent NEI year) may be more appropriate for modeling in view of unusual meteorology, transport patterns, exceptional events (i.e. large wildfires), lack of air pollution events, or other factors that may vary from year to year. See section 2.3.1 for more information on episode selection. The choice of the base year should be discussed with the appropriate EPA Regional office as part of the SIP planning process for the attainment demonstration.

For attainment planning in particular, the choice of a future year for an inventory depends on the nonattainment classification of the nonattainment area, as described in section 2.3.2. For ozone and PM_{2.5}, in most cases the future modeling year will be the expected attainment year. Requirements for selecting appropriate future years for modeling are provided in the ozone and PM_{2.5} NAAQS implementation rules. For regional haze, the future year will depend on the end-date of the planning period being examined.

¹⁷ There are additional regulations related to reasonable further progress (RFP) requirements for both the ozone and PM_{2.5} NAAQS.

2.7.2 What Base Year Emission Inventory Data Are Needed to Support Air Quality Models?

Air quality models require hourly emissions of modeled species for each grid cell and model layer in the modeling domain. For the base year, the inventories are called the *base year inventory for modeling*. To meet the input requirements of models, the inventory must have pollutants that are the scientific precursors (pollutants that impact the relevant chemistry) to the ozone, PM_{2.5}, and/or regional haze being addressed in the modeling demonstration. The time frame of the emissions inventory should be consistent with the period being modeled. The inventory should include states, counties, and tribes that are covered by the spatial extent of the modeling domain. Additionally, the emissions sources included should be comprehensive, including emissions from all source categories. As explained with additional detail below, this includes point sources, non-point stationary sources, on-road and nonroad mobile sources, fires, and biogenic sources.

2.7.3 What Pollutants Should Be Included in Base Year Inventories?

Because many sources emit more than one of the precursor pollutants, and because the precursor pollutants have the potential to be transported across state boundaries, the EPA encourages air agencies to develop comprehensive inventories to support integrated, regional-scale modeling, and control strategy development for ozone, PM_{2.5}, and regional haze. However, there are some considerations for which pollutants to include in inventories for the purpose of supporting air quality modeling.

For 8-hour ozone NAAQS modeling, the pollutants to be inventoried for modeling are VOC, NO_x, and CO. For PM_{2.5} NAAQS modeling, the pollutants to be inventoried are primary emissions of PM_{2.5} and PM₁₀ (including both the filterable and condensable portions) and emissions of SO₂, NH₃, VOC, NO_x, and CO. While certain PM_{2.5} precursors may not be considered precursors for planning purposes in some nonattainment areas¹⁸, inclusion of all precursors is a prerequisite for appropriate application of air quality models for modeled attainment demonstrations. For regional haze, the pollutants to be inventoried include all of the pollutants and precursor pollutants identified for ozone and PM_{2.5}. While CO does not need to be included in the *planning inventories* associated with ozone and/or PM_{2.5} SIP submissions (as described in the EI SIP Guidance), it should be included for modeling purposes because CO plays an important role in atmospheric chemistry.

¹⁸ See the PM_{2.5} SIP requirements rule for detailed information on the definition of “planning” precursors for PM_{2.5} nonattainment areas.

For modeling purposes, emissions inventories of these pollutants undergo many transformations to prepare the inventories for use in air quality models. These transformations include chemical speciation, which is described below in section 2.7.8.2. As part of the chemical transformations of VOC, in particular, total organic gases (TOG) are calculated to include lower reactivity compounds that are not included in the regulatory definition of VOC, but nonetheless have some role in ozone and/or PM_{2.5} formation.

2.7.4 What Temporal Resolution Should Be Used for Base Year Inventories?

The emissions inventories should cover the time periods associated with the modeled time period. Different approaches to accomplishing this goal arise because of the nature of ozone, PM_{2.5}, and regional haze problems.

For ozone, the episodic nature of 8-hour ozone exceedances leads to inventories that may reflect a specific period being modeled. For this reason, the *planning* inventories should be provided as an ozone season day inventory¹⁹ (as described in the EI SIP Guidance). For the nonattainment area, the planning ozone season day inventories are also often used for modeling inventories.

For PM_{2.5}, both annual and daily NAAQS result in different inventory temporal possibilities for the modeling episode, depending on which NAAQS a particular nonattainment area must address in the SIP. As a result, the *planning* inventories may be annual, seasonal, or both. Like ozone, the planning inventories may also be used as the starting point for the modeling inventories. For example, an annual planning inventory will need to be temporally allocated to the days and hours of the time period used for PM_{2.5} modeled attainment demonstrations. This is the case for both annual modeling and when the air agency has chosen to use a seasonal demonstration as part of a 24-hour demonstration.

Modeling inventories also include areas outside the nonattainment area, for which ozone season day or average season day (for PM_{2.5}) emissions may not be readily available. In these instances, air agencies may elect to start with an annual inventory and use an emissions model to adjust the annual emissions to reflect the modeling period. This may not be advisable in every case; in particular, mobile source emissions are highly variable with meteorology and day of the week, and are often available on a monthly or even daily basis that reflects variability in temperature, traffic patterns, and other factors. In addition, more detailed temporal data from electric generating units (EGUs), biogenic sources, windblown dust, sea salt, lighting, wildfires,

¹⁹ The definition of “ozone season day” emissions specifies weekday emissions and is intended to reflect the periods of emissions associated with monitored ambient ozone exceedances.

prescribed fires, agricultural burning, or other sources should be used when available to enhance the technical quality of the modeled attainment demonstration.

For regional haze, the use of annual emissions inventories is appropriate given the nature of the regional haze problem. However, the same considerations apply for the inventory's temporal aspects as they do in the cases above; more detailed temporal data should be used as the inventory starting point when it is available for important sources of the pollutants included in the inventory.

2.7.5 What Spatial Coverage Is Needed for Base Year Inventories?

Modeling inventories must cover all areas of the modeling domain, which will include areas outside of a nonattainment area and Class I areas and most often includes areas in neighboring states or tribes. This subsection addresses areas within and outside the nonattainment area separately.

2.7.5.1 Areas Within the Nonattainment Area

As mentioned above, planning inventories (which are a CAA and regulatory requirement for ozone and PM_{2.5} SIPs) include emissions within the nonattainment area. The EPA expects that modeling inventories will be consistent with those planning inventories; however, some exceptions may exist. Where possible, the planning inventories (which are typically annual or seasonal) can be a sum (for annual data) or average (for ozone or PM_{2.5} season day data) of day-specific or hour-specific data used for modeling. In some cases, however, this approach may not be sufficient for modeling purposes. For example, greater spatial and temporal detail are needed for on-road mobile modeling inventories as compared to the base year (planning) inventory for the nonattainment area. For the planning inventory, one goal is to allow for the repeatability of the approach in order to create average, seasonal, or annual inventories for use in rule requirements, such as reasonable further progress or conformity demonstrations. That goal is not necessarily compatible with the modeling need for spatial and temporal detail. In cases where some differences between planning and modeling inventories are unavoidable, air agencies should attempt to promote consistency where feasible. More information on the temporal basis of inventories is provided in section 4.5 of the EI SIP Guidance.

2.7.5.2 Areas Outside of the Nonattainment Area

For air quality modeling, emissions inventories are often needed for areas outside the nonattainment area. Developing modeling inventories for these areas should be relatively straightforward and can be included as part of the SIP planning inventories. For areas outside of

the air agency's jurisdiction, however, it can be more difficult for air agencies to develop the inventories themselves. In these cases, the EPA encourages participation in regional modeling efforts, which are designed to allow sharing of data and help promote consistent approaches across state boundaries. When those organizations lack the needed inventories, the EPA recommends using the EPA's publicly available emissions, as described in the next section.

2.7.5.3 Areas Outside of the United States

In some cases, the modeling domain may need to extend into areas of Canada and/or Mexico. In this case, emissions modelers will need to include emissions from these countries in their modeling domain. Both Canada and Mexico have emission inventory programs that provide inventories that can be used in modeling, and the EPA includes the latest available inventories from these countries in its national emissions modeling platform. States are encouraged to use the latest available data for these countries. While the EPA is one source for that data, states may work directly with other countries or work with their EPA Regional office to try to get inventories that are more current or otherwise improved over what is available directly from the EPA.

2.7.6 How Can the National Emission Inventory Be Used by Air Agencies?

The EPA recommends that state, local, and tribal agencies start with available inventories suitable for air quality modeling of the selected time period(s). If no such inventories are available from a prior state or tribal effort, from regional modeling groups, or from some other source, air agencies may choose to derive an inventory suitable for use with models from EPA-provided information. Two sources of information are available, as described below. In both cases, the EPA expects that air agencies will only use such data after additional review to ensure the appropriate quality of the data for SIP planning purposes.

First, the National Emission Inventory (NEI) provides criteria air pollutant and hazardous air pollutant emissions as annual emissions totals for most (if not all) sources of emissions relevant for ozone, PM_{2.5}, and regional haze implementation purposes. Air agencies may use the most recent public release of the NEI as a starting point for inventory development. The data and documentation are available from the [NEI Website](#).

Additionally, the EPA provides emissions modeling "platforms" that are based on the NEI and can be a starting point for air agencies. The modeling platform data provide additional information not available from the NEI, such as daily EGU and fire emissions, monthly nonroad emissions, biogenic emissions and/or input to biogenic emissions models, and inputs to mobile source models. Furthermore, these modeling platforms usually include future-year emissions

projections. Both base and future-year data are provided in a format used by emissions models and can, therefore, be more readily adopted by air agencies that need to process emissions for use in air quality models. The data and documentation are available from the latest platform release at the [Air Emissions Modeling Website](#).

The detail and accuracy of the EPA emissions inventories and platforms may or may not be sufficient for use in any particular SIP. Air agencies should review the emissions and associated documentation and make improvements where deficiencies exist. Such improvements will often be necessary to demonstrate appropriate model performance, as described in section 3. Additional degrees of review are needed for areas closer to the nonattainment area. For example, EPA data may be sufficient for estimating emissions in states that are hundreds of kilometers upwind or downwind of the nonattainment area, but may not be sufficient for estimating emissions closer to the nonattainment area because those emissions can have a greater impact on the final results of the attainment demonstration.

2.7.7 How Should Base Year Emissions Be Created?

Emission inventory data from at least five general categories are needed to support air quality modeling: stationary point-source emissions, stationary area-source emissions (also called nonpoint), emissions for on-road mobile sources, emissions for nonroad mobile sources (including railroad and marine vessels), and biogenic/geogenic emissions. A sixth category of wildland fires also exists and includes day-specific emissions from wildfires and prescribed burns. These fire emissions are included as an “event” source in the NEI. Emissions inventories are expected to include “all” sources of emissions; if an air agency wishes to exclude a particular source (e.g., because it is a very small contributor), then the air agency should document the reasons such omissions are acceptable. In addition, some “traditional” nonroad mobile sources (e.g., airports and rail yards) can also be included in inventories as a point source. For example, in the NEI, airports and rail yards are included as point sources and railroad and marine vessel emissions as part of the nonpoint data category.

The EI SIP Guidance (U.S. EPA, 2017b) addresses numerous details about emissions inventory development. Readers are encouraged to refer to information in that document as a resource for building base year emissions inventories. That guidance contains additional information on the definitions of the data categories (point sources, nonpoint sources, etc.), provides more information about emissions estimation for each data category, includes a process for prioritization of inventory development, and includes quality assurance recommendations. All of this information is highly relevant to inventories developed for air quality modeling. In the remainder of this section, we provide a basic description of the data categories and their base

year emissions and additional information needed for their use in modeling applications where appropriate.

2.7.7.1 Point Sources

Point sources are emissions sources that are attributed to specific facilities and emissions release points within those facilities. The [Air Emissions Reporting Rule \(AERR\)](#) provides information on how to define which sources to include as specific point sources in the inventory. This definition is the same as the New Source Review program major source definition, with a lower potential-to-emit threshold for nonattainment areas. More information on the relationship between SIP inventories and the AERR and how that affects SIP inventories is available in the EI SIP Guidance. For modeling inventories, data developers may include sources with emissions smaller than the required reporting threshold, and should be careful to prevent double counting with nonpoint source categories that may overlap with some of these smaller sources. This is especially a concern when compiling point and nonpoint inventories from different sources, because a nonpoint inventory is compiled using certain assumptions about what an associated point source inventory includes. This issue is described as “nonpoint reconciliation” and is discussed further in the EI SIP Guidance.

Point source inventories for modeling should be compiled at a minimum by country, state/tribe, county, facility, unit, process or source category code (SCC) and by “release point” or stack (see references below to point-source inventory development). The point source data should include information on the location of the sources (e.g., latitude/longitude coordinates); their stack parameters (e.g., stack diameter and height, exit gas temperature and velocity); and operating schedules (e.g., monthly, day-of-week, and diurnal). Information on existing control device types, measures and associated emissions reductions are also useful to identify sources that might be further controlled and to prepare future year inventories.

For air quality modeling purposes, the precision of the latitude/longitude values can be very important, as it will determine the modeled grid cell of the source. It is recommended to use coordinates reported to one-ten-thousandth of a degree (four digits after the decimal point) to give a precision of approximately 30 feet. In addition, metadata about the latitude/longitude should ideally be collected, such as the horizontal reference datum code used (e.g., WGS84). The EPA provides a data standard for latitude/longitude which can be considered when collecting, storing, and reporting latitude and longitude data values ([see here](#)). When working with other states to share point source data, it may be useful to use the same horizontal reference datum across states, such as the World Geodetic System of 1984 (WGS84). Other datum codes listed on the EPA [Data Element Registry Services](#) include the North American Datum of 1927 (NAD27) and the North American Datum of 1983 (NAD83).

For modeling needs, many point sources will also be post-processed for the estimation of plume rise of the emissions vertically through layers of the atmosphere as modeled by the air quality model. This plume rise depends on the stack parameters (listed above) and on meteorological conditions. Plume rise can be calculated by emissions models or as part of air quality models (either approach is acceptable and the results can be equivalent). In this latter case, inventory developers are responsible only for identifying for which sources' plume rise will be computed using tools available in emissions models.

Also, for modeling needs, hourly emissions data are usually a starting point for inventories of EGUs. In most cases, such data are readily available from Continuous Emissions Monitoring Systems (CEMS) installed as part of EPA trading programs²⁰ and include hourly emissions of NO_x, SO₂, CO₂, and heat input. The heat input data can be used to estimate hourly emissions of other pollutants (such of primary PM_{2.5} emissions) using facility-specific emission factors or other emission factors. The EPA's modeling platforms also include these hourly data.

2.7.7.2 Nonpoint Sources

Nonpoint sources are also called "area sources." These sources collectively represent sources of emissions that have not been inventoried as specific point sources. The individual sources within the nonpoint emissions county totals are typically too small, numerous, or difficult to inventory using the methods for point sources. The nonpoint emissions data should be compiled by country, state/tribe, county, and SCC, and sometimes by emission type (e.g., hoteling and cruising for commercial marine emissions in the NEI) and Geographic Information Systems (GIS) shape (for locomotive and commercial marine emissions in the NEI). The specification of nonpoint emissions at a more detailed resolution than county is typically not necessary for modeling inventories, but can provide a more detailed spatial representation for areas where such an approach is needed. Spatial allocation of emissions with spatial surrogates (see section 2.7.8.3) can be equally effective.

2.7.7.3 On-Road Mobile

Emissions from on-road vehicles are the result of several emission processes, including the combustion of fuel while vehicles are starting, idling, and moving, evaporation of fuel from the fuel system and during refueling, and from brake wear and tire wear.

²⁰ CEM data are provided by the EPA's Clean Air Markets Division in a format suitable for use in emissions processing at the [Air Markets Program Data Website](#). From this page, click the "Prepackaged data" tab and scroll to the bottom to download the data in a form that can be input into SMOKE.

Mobile source inventory modelers should use the latest version of the [Motor Vehicle Emission Simulator \(MOVES\) for on-road mobile source emissions](#). They should also subscribe to the [MOVES email list](#) to be notified of any bug fixes or updates to the MOVES model. For on-road emissions in California, the most recent EPA-approved version of the [Emission FACTors model \(EMFAC\)](#) should be used. In addition, the [Sparse Matrix Operator Kernel Emissions \(SMOKE\)](#) emissions modeling system includes tools that support the use of MOVES emission factors with SMOKE, and thereby allows modelers to account for the sensitivity of on-road emissions to temperature. SMOKE uses county-specific inputs and gridded hourly temperature and other meteorological information, which is typically based on the same meteorological data used for air quality modeling.

Emissions modelers have a choice in MOVES between “inventory” mode and “emission factors” mode (which creates emission factors that can be further processed using SMOKE-MOVES). Both approaches are valid for supporting air quality modeling for SIPs. More information on the different ways of running MOVES is provided in the [MOVES documentation and guidance](#).

Modelers should consider using a refined approach (such as the SMOKE-MOVES system, day-specific MOVES runs, or some other approach) for use in emissions modeling needed for modeled attainment demonstrations. The SMOKE-MOVES approach first generates emissions rates from MOVES by process (running, start, vapor venting, refueling, etc.), vehicle type, road type, temperature, speed, and hour of day, according to specified fuel parameters and other inputs. Then, subsequent steps apply the appropriate MOVES emissions rates along with vehicle miles traveled (VMT) and vehicle population data for the counties and grid cells in the modeling domain for each hour of the modeling episode.

The MOVES model allows modelers to override default database settings to obtain a locality-specific on-road inventory, and EPA strongly encourages data developers to develop and use MOVES input databases that are specific to the states and counties within the modeling domain. The MOVES Technical Guidance²¹ discusses when local data should be used in place of model default data, as well as potential sources of local data.

For some input parameters, there is overlap with the inputs needed for other models, such as the nonroad mobile models. For example, meteorology and fuels information is needed to drive both the mobile and non-road emissions models. Efforts should be made to use the same source of data across multiple categories when the inputs are shared by multiple models. Not doing so calls into question the validity of one or both approaches. Air agencies should explain

²¹ The most current version of this document is available on the [MOVES website](#).

the use of shared inputs, or reasons for not using them, as part of the documentation prepared with their modeled attainment demonstration.

On-road emissions and VMT should be compiled at least at the country, state/tribe, county, and SCC level. Vehicle population data by county and vehicle type should also be compiled as well as idling hours, if available. For some inputs such as VMT, modelers may optionally compile and use data for individual road segments (called “links”). Link approaches require starting and ending coordinates for each road link. Link-based modeling is typically performed for fine scale (i.e., 4-km or finer) modeling studies. Travel Demand Models (TDMs) can be a source of data needed to develop link-based approaches. In regional scale modeling, county-level on-road emissions can be allocated onto road links using spatial surrogates that are generated based on link data and mapped into the modeling grid cells using appropriate weights.

2.7.7.4 Nonroad Mobile Equipment

Nonroad mobile equipment emissions result from the use of fuel in a diverse collection of vehicles and equipment, and the EPA’s NONROAD emissions model estimates these emissions. The NONROAD model was originally a separate model, but has now been incorporated into the MOVES model (starting with MOVES2014a). Nonroad emissions should be compiled as country, state/tribe, county and SCC totals.

For the MOVES2014a version of MOVES and later versions, the MOVES model should be used to calculate nonroad source emissions. MOVES2014a (and newer versions) includes features not previously available in MOVES that simplify processing of emissions output and includes updated fuel input files that result in small changes in emission results. In addition, the prior tools available for nonroad emissions estimations (NONROAD2008 and NMIM2008) may no longer work with current operating systems, and the EPA cannot continue to provide technical support for these models. Therefore, the EPA recommends that for modeling nonroad emissions, MOVES2014a or newer versions be used for all new SIP development, although state and local agencies that have already completed significant work with MOVES2014, NONROAD2008, or NMIM2008 can continue to do so to allow for timely submission of the SIP. As a general matter, air agencies should review and possibly update and customize the MOVES model inputs to give better emissions estimates for their state.

Unlike models for onroad emissions, the EPA does not specifically “approve” nonroad models. However, use of alternative models can be justified as part of a SIP submission. For example, California has previously developed and used a state-specific approach for estimating its nonroad source emissions for SIP purposes, called [OFFROAD2007](#). Although this model has now been replaced by [category-specific methods](#) for many categories, it is still the default approach for categories not listed with newer methods, as described on the OFFROAD website. Any use

of such an alternative approach is subject to review by the EPA as part of the review of the SIP, and thus states are encouraged to coordinate with Regional offices on any use of alternative models. The MOVES nonroad capabilities include more than 80 basic and 260 specific types of nonroad equipment and further stratifies equipment types by horsepower rating. Fuel types include gasoline, diesel, compressed natural gas (CNG), and liquified petroleum gas (LPG). The nonroad capabilities of the MOVES model estimates emissions for all criteria pollutant and precursors from both exhaust and non-exhaust processes (diurnal, refueling spillage, vapor displacement, hot soak, running loss, take permeation, hose permeation, and crankcase emissions). MOVES supports many SIP-related inventory development needs, including support for partial counties and seasonal emissions.

Air agencies are encouraged to replace default model inputs with more representative data. Common input adjustments include equipment population, geographic allocations, and local growth rates. If agencies make changes to default model values, the agency should submit the input files to the EPA as well as a description of why the defaults were changed. As mentioned in the previous discussion of on-road mobile emissions, for some input parameters, there is overlap with the inputs needed for other models, such as the on-road mobile models (e.g., meteorology and fuels). Efforts should be made to use the same source of data across multiple categories when the inputs are shared. Not doing so calls into question the validity of one or both approaches. Air agencies should explain the use of shared inputs, or reasons for not using them, as part of the documentation provided with their inventories.

2.7.7.5 Nonroad Mobile: Commercial Marine Vessels, Locomotives, and Aircraft

Emissions from commercial marine vessels, locomotives, and aircraft are estimated in other ways as described in detail in the EI SIP Guidance. These sources can be particularly important for urban areas and in some Class I areas (especially in coastal areas). The EI SIP Guidance contains information about methods available to estimate emissions from these sources.

Commercial marine vessel emissions can be a particular challenge for nonattainment areas that include ports or are adjacent to major shipping lanes. While the level of emissions from these vessels can be outside of the control of state air agencies (coming under national rather than state jurisdiction), it is still important to accurately represent these emissions when they are significant contributors in the vicinity of a nonattainment area or Class I area. Vessels are divided into the largest ocean-going “category 3” (C3) vessels and the smaller “category 1” (C1) and “category 2” (C2) vessels such as tug boats, ferries, support vessels, fishing vessels, and others. Commercial marine emissions include both in-port emissions and underway emissions, with most (~90% of nationwide emissions) emissions associated with underway activity. For the planning inventories covered by the EI SIP Guidance, air agencies need to include only those

emissions within state waters. For the modeling inventories, however, air agencies may also need to include emissions in Federal waters when the modeling domains extend more than a few miles offshore. This is especially important for coastal areas where offshore commercial marine emissions may be an important contributor to ozone and/or PM in the nonattainment area and/or visibility impairment in Class I areas.

The current EPA methods for estimating commercial marine emissions use a bottom-up approaches for C1, C2, and C3 vessels. The method uses activity data from Entrance and Clearance Waterborne Commerce (both from the Army Corps of Engineers) and from a 2007 EPA census of C1 and C2 vessel activities. The most recent documentation for EPA methods is provided in the [2014 NEI v2 Technical Support Document](#), section 4.19.

Uncertainties in estimating commercial marine emissions with EPA's current methods remain. Thus, the EPA strongly encourages air agencies preparing modeling inventories to seek out, develop, and use local-specific information about their ports and waterway vessels to better compute emissions whenever possible, and particularly when the commercial marine sector is a major factor in emissions conditions that lead to nonattainment and/or visibility impairment in Class I areas.

2.7.7.5 Biogenic Emissions

Biogenic sources are a subset of natural emissions sources that may be an important component of the emissions inventory. Vegetation (i.e., forests and crops) is the predominant biogenic source of VOC and is typically the only source that is included in a biogenic VOC emissions inventory. Additionally, microbial activity in the soil contributes to biogenic NO emissions.

Biogenic emissions from vegetation and soils are computed using a model that utilizes spatial information on vegetation and land use and environmental conditions of temperature and solar radiation. The model inputs are typically horizontally allocated (gridded) data, and the outputs are gridded biogenic emissions which can then be speciated and utilized as input to chemical transport grid models. Several models exist, and are described more fully in section 2.7.9.2 and the EI SIP Guidance.

Modeled biogenic vegetation emissions are significant for understanding ozone formation, particularly in the Eastern U.S., and the dependence on meteorology makes using case-specific meteorology very important. In addition, the impact and model characterization of biogenic monoterpene and sesquiterpene emissions on secondary aerosol formation is important in many areas of the U.S., most notably the Southeast. Therefore, biogenic emissions should be

generated using hourly meteorology reflective of the time period being modeled to best capture important relationships between temperature, solar radiation, and biogenic emissions.

2.7.7.6 Geogenic and Other Natural Sources

Geogenic emissions are primarily the result of oil or natural gas seeps, soil wind erosion, and sea salt spray. In addition, lightning may also be an important contributor to natural NO emissions in an inventory area. Volcanoes and fumaroles (i.e., vapor or gas vents in a volcanic region) can be additional sources of geogenic emissions. SIP developers should consider these sources as part of their conceptual description. If geogenic sources are identified as potentially contributing to air quality, such emissions should be included in the modeling.

Oil or Natural Gas Seeps

The U.S. Geological Survey Bureau of Ocean Energy Management (BOEM) has [documented emissions from oil and gas seeps in the Gulf of Mexico](#). The University of California Santa Barbara also [provides inventory information about California- area seeps](#). This is an area of ongoing research.

Windblown Dust

Wind erosion may contribute substantially to PM emissions in an area. Emissions from wind erosion is an area of active research and development, and multiple approaches for estimating wind-blown dust emissions are available. For example, the EPA's CMAQ model includes a module that dynamically estimates hourly natural emissions of fine and coarse dust particles due to wind action over arid and agricultural land. The windblown dust approach is based on the work of J.S. Fu et al. (2016). Other examples of windblown dust approaches include Draxler, Ginoux and Stein (2010), Mansell et al. (2006), and Sundram et al. (2004).

Air agencies using any "in-line" approach for windblown dust emissions should evaluate the results of the approach to determine if it provides a reasonable representation of dust emissions in their modeling domains. Air quality models can have an option to output in-line emissions for evaluation, so that modelers can assess and quality assure the emission estimates directly.

Sea Salt and Other Ocean Emissions

The interaction of sea-salt particles in coastal environments with air chemistry can impact concentrations of PM_{2.5} and gas-phase species in the atmosphere. Various emissions estimation methods are available to account for sea salt emissions. For example, the CMAQ model has been updated to account for these emissions, so that emission inventory developers are able to

rely primarily on the air quality model to internally calculate sea-salt emissions. Additional information for CMAQ is available in Kelly et al., (2010) and Gantt et al., (2015). For CAMx, additional information on sea salt simulations is available in Athanasopoulou et al. (2008). When an in-line approach is used, emissions should be output from the model so that modelers can assess and quality assure the emission estimates directly. When an in-line approach is not used, modelers should consider the possible need for including sea salt emissions data as an input to the air quality model.

In addition to particulate impacts, ozone in coastal areas can be affected by ocean emissions of halogen compounds including chlorine, bromine, and iodine. Many approaches could be taken to represent those emissions. For example, Yarwood et al. (2014) describes an updated chemical mechanism to include halogen chemistry and a CAMx preprocessor that was used to estimate emissions of halogen precursors in coastal areas, and Sarwar (2015) describes a similar halogen chemistry implementation that has been used in CMAQ. Numerous other references are available in the peer reviewed literature that describe halogen chemistry impacts on ozone formation and modeling of that process.

Lightning

Another natural source of emissions is lightning, which produces NO that forms NO₂ in the presence of ozone or in a photochemically reactive atmosphere. The NO and NO₂ are formed in the mid-upper troposphere and can impact the vertical distribution of reactive nitrogen as well as ozone. Because lightning is not a direct source of NO₂, accounting for this source category is more important for air quality modeling purposes than for SIP planning inventory purposes.

Various methods for estimating lightning emissions could be used. For example, the EPA's CMAQ model includes a parameterized approach to estimate NO_x emissions and the vertical distribution that is generated from lightning. The peer reviewed literature contains both a description of the approach (Allen, 2012) and a model evaluation (Appel, 2010). In addition, Koo et al. (2010) describe estimating annual total lightning NO emissions for North America and then spatially and temporally allocating those emissions to model grid cells using convective precipitation activity as a surrogate.

Volcanoes and Fumaroles

Basic information on volcanic gas is available from the [USGS](#). The USGS also has a monitoring program focused on predicting eruptions. Although this program does not include information on pollutant concentrations, the [monitoring program website](#) provides potentially useful maps of volcanos using the "Find a U.S. Volcano" pull-down menu near the top of the site. Finally, the [publications related to volcanoes search](#) allows for searching publications for pollutant

keywords such as CO₂, SO₂, gas, hydrogen sulfide, and volcanic gas. Most of these emissions-related articles focus on information in California, Washington, Hawaii, and the Yellowstone area.

2.7.7.7 Wildland and Cropland Fires

Wildland fires are generally defined as any non-structure fire that occurs in wildland (an area in which human activity and development are essentially non-existent, except for roads, railroads, power lines, and similar transportation facilities and structures, if any, are widely scattered). Cropland fires are any non-structure fire that occurs on croplands. The Exceptional Events Rule²² (which applies to NAAQS implementation) and the Regional Haze Rule define two types of fire that can occur on wildland:

- *Prescribed fire* means any fire intentionally ignited by management actions in accordance with applicable laws, policies, and regulations to meet specific land or resource management objectives.
- *Wildfire* means any fire started by an unplanned ignition caused by lightning; volcanoes; other acts of nature; unauthorized activity; or accidental, human-caused actions, or a prescribed fire that has developed into a wildfire. A wildfire that predominantly occurs on wildland is a natural event.

Inventories used for ozone, PM_{2.5}, and regional haze modeling purposes should include wildland (wild and prescribed) and cropland fire emissions. Wildland and cropland fires can emit large amounts of primary PM_{2.5} as well as precursors that can react in the atmosphere to form ozone and secondary PM_{2.5} downwind potentially impacting both urban and Class I areas. Thus, wildfire and prescribed fire emissions should be included in the nonattainment area inventories when and where these emissions occur within the modeling domain during time periods being modeled. Cropland fires can also be inventoried when and where these emissions occurred or as a nonpoint source.

Detailed information about how the EPA develops wildland and cropland (Pouliot et al, 2016) fire inventories can be found in the latest version of an NEI Technical Support Document, such as that provided with the 2014 NEI. The EPA's approach for wildland fires relies on a combination of satellite detection of fires merged with on-the-ground observational data where available. The EPA encourages the use of ground-based observations and local fuel information whenever possible, as these factors can have a large impact on the emissions. One option for obtaining fire date and location information includes the latest version of the

²² See 81 FR 68216, October 3, 2016.

Satellite Mapping Automated Reanalysis Tool for Fire Incident Reconciliation (SMARTFIRE) system (Du et al., 2013; Sullivan, et al., 2008). Detailed information on the SMARTFIRE system is available in Raffuse et al., 2007. Additional references and information are available as part of the [2014 NEI Technical Support Document](#). Other sources of fire location, size, duration, and emissions may be available and could be used instead of the SMARTFIRE approach. Examples of other approaches include the WRAP FETS (JFSP, 2013) and the Fire Inventory from [NCAR \(FINN\)](#).

Important aspects of wildland fire that impact resulting emissions estimates include the location of the fire, timing of the fire (start and end date/time), fire type (wild, prescribed, or cropland), fuel type, fuel loading, area burned, and fuel moisture. Daily emissions are allocated to hour of the day using profiles based on fire type. VOC and primary PM_{2.5} emissions are speciated to specific compounds based on profiles generated from laboratory and field testing. The activity information noted is not just critically important for estimating emissions, it is also important toward estimating the heat flux of the fire and subsequent plume rise in the photochemical model. The estimated plume rise can have a large impact on how far downwind smoke can be transported (to a nonattainment area and/or Class I area). Combustion phase can also be an important consideration when modeling wildland fires in terms of emissions, plume rise, and vertical allocation of emissions. Fires that are largely smoldering (such as peat fires) can have different emission factors and have a different profile of VOC and primarily emitted PM_{2.5} emissions.

Since fire emissions can be a large source of emissions, the treatment of fires should be discussed with the relevant EPA Regional office(s) as part of the modeling protocol development process.

2.7.8 What Other Data Are Needed to Support Emissions Modeling?

For modeling purposes, emission inventories need to be converted through emissions modeling from their original resolution (e.g., annual emissions by point source or count) to air quality model input files. Air quality models generally require emissions inputs to be specified by model grid cell, hour, and model chemical species. Modeling inventories also identify which point sources should have their plume rise computed. This section describes the ancillary data that modelers should collect and prepare to allow emissions models to convert the emission inventory data into air quality model inputs.

2.7.8.1 Temporal Allocation

Ancillary data for temporal allocation are necessary for stationary point, stationary area, and all mobile sources. To facilitate temporal allocation of the emissions, factors called “temporal

profiles” should be created to convert annual emissions to specific months (i.e., monthly profiles), average-day emissions to a specific day of the week (i.e., weekly profiles), and daily emissions to hours of the day (i.e., hourly profiles). Additionally, a cross-reference file is needed to assign the temporal profiles to the inventory records by SCC, facility, geographic area such as state or county, or some other inventory characteristics. Where available, the operating information that may be available from the point-source inventory should be used to create inventory-specific temporal factors. The EPA provides a starting point for the temporal profiles and cross-reference files as part of the latest modeling platforms (previously described), available at the [Air Emissions Modeling website](#).

The EPA has developed a SMOKE utility program (Gentpro) that estimates temporal profiles for residential wood combustion (RWC), agricultural NH₃ from animals, and other generic (user-defined) area sources by relating meteorology to air emission fluxes. Gentpro reads in hourly gridded meteorological data (temperature and wind) from the Meteorology-Chemistry Interface Processor (MCIP)²³ and a gridded spatial surrogate to produce temporal profiles and cross-reference data. Annual MCIP input data are required to calculate temporal profiles with Gentpro and the spatial surrogates are needed to identify the grid cells for computing county-averaged meteorology variables. The Gentpro program is described in the latest [SMOKE User's Manual](#).

For RWC, Gentpro allocates emissions to specific days from annual totals based on a regression equation that was developed by relating daily minimum temperatures and chemical tracers of RWC. This approach results in more RWC emissions assigned to periods of colder temperatures using a user-defined temperature threshold that restricts RWC emissions to days with morning lows below a specific value. Air agencies that use EPA's emissions data for this category should note that this approach has been used to temporally allocate the RWC emissions.

For agricultural NH₃ from animals (i.e., from concentrated animal feeding operations, or CAFOs), Gentpro allocates annual, monthly or daily emissions to hourly emissions based on empirical equations derived from investigations of emissions from animal waste decomposition as a function of temperature and wind speed. The resolution of emissions input to Gentpro for this sector depends on the available data. Air agencies that use EPA's emissions data for this category should note that this approach has been used to temporally allocate agricultural NH₃ emissions from CAFOs.

²³ MCIP is a meteorology postprocessing program. It is typically used to convert WRF meteorological model output data to CMAQ input format. The latest version of MCIP can be found [here](#).

For point sources, hourly CEMS data are recommended for use in base year emissions modeling rather than temporal profiles, where such CEMS data are available, and with the following caveats. CEMS data are collected as part of emissions compliance and/or trading programs. Because these programs require complete hourly data, alternative emissions values are assigned to hours when CEMS devices are not functioning. These alternative values can be extremely high values (compared to actual emissions rates), in order to motivate CEMS operators to provide a complete data record to the extent possible. As a result, CEMS data may have some anomalies and should be reviewed prior to use in a modeling study. The CEMS data fields include an emissions method code, which identifies the hours with alternative values. Furthermore, CEMS data may be available for only part of a year; therefore, for annual modeling, users should be careful to ensure CEMS data are used for the appropriate periods and total annual emissions are temporally allocated to fill in the other hours of the year.

For wildland fire emissions, the EPA recommends using daily, location-specific fire data such as the NEI “events” sources. These sources can have a large impact on ambient levels of ozone and PM_{2.5}, and on regional haze. Although emissions from these sources are largely uncontrollable, the inclusion of all emissions sources (including biogenic and uncontrollable sources) is needed to accurately predict pollutant concentrations and derive relative response factors for both PM and ozone.

As a general matter, the temporal allocation approach should remain consistent between the base year modeling and the future year modeling. Consistency is important when using the RRF approach to make future year projections of ozone, PM_{2.5} and/or visibility, because the results of that approach can be affected by changes in when emissions are modeled to occur. In general, this means that the temporal allocation will be the same between base and future years, except when an intentional change is made to reflect a real expected change in the temporal distribution. An example of such a change includes intentionally reducing emission peaks from units during incidents of poor air quality. In addition, modeling can be specially done for the current year with an emissions case which uses “typical” emissions temporal allocations for major sources, and this case may be different from the current year case, where actual source schedules are used to evaluate model performance.

For future-year modeling there are two choices for representing EGU emissions derived from CEMs data and wildfire emissions. Modelers can use day-specific emissions for both the base and future years, or a “typical year” temporal allocation (averaging) approach can be used to create representative emissions. If a typical year approach is used, it should include similar daily temporal variability as could be expected for any given year (in most cases, the daily temporal variability also needs to be consistent with the base year meteorology). Air agencies should

discuss the temporal approach to fires (see also section 2.7.11) and point sources with the appropriate EPA Regional office as part of the modeling protocol development process.

2.7.8.2 Chemical Speciation

The emissions models also need information about the chemical species of the VOC, NO_x, and PM_{2.5} emissions for all emissions sources. These data are used to disaggregate the total VOC, NO_x, and PM_{2.5} emissions to the chemical species expected by the air quality model and are called speciation “factors” or “profiles.”

The EPA provides a starting point for the VOC, NO_x, and PM_{2.5} speciation data, which are available with the EPA modeling platforms (previously described). The VOC and PM_{2.5} speciation profiles are based on the SPECIATE database, which is available on the [SPECIATE website](#). In addition to the speciation profiles, a speciation cross-reference file assigns speciation profiles. The default EPA speciation cross-reference assigns profiles to sources using SCCs. These speciation profiles in many cases are highly uncertain and should be assessed and improved where possible for emissions source categories that are critical to model performance.

For large or critical VOC and PM_{2.5} sources in the modeling domain, air agencies should consider determining the individual chemical compounds contributing to the total VOC and PM_{2.5}. If collected, this information should then be used to compile speciation profiles for the critical facilities or source categories. These speciation profiles should be assigned to the facilities by updating the speciation cross-reference file to support a facility-specific or facility-SCC-specific assignment.

For VOC, low reactivity chemical components including methane have traditionally been calculated by applying a factor to the VOC emissions to calculate total organic gases (TOG). These TOG emissions are then split during emissions processing into the VOC model species that include methane. In limited situations, air agencies may want to investigate the extent that methane emissions and low volatility compounds play a role in ozone episodes and/or secondary PM_{2.5} formation. Additional efforts going beyond the use of the default VOC-to-TOG profiles from the speciation profiles may develop over time.

In some limited cases, it may be of interest to include methane emissions inputs to air quality models to achieve sufficient model performance for a modeled attainment demonstration. Approaches can include incorporating methane emissions from other sources into emissions inventories used for modeled air quality. For example, the MOVES model estimates methane emissions directly, so there would be no need to use VOC speciation to estimate those emissions. Air agencies considering methane as a contributing factor should consult with their

EPA Regional office to discuss the best sources for such data as this inventory development area is undergoing many changes at this time. Furthermore, more specific VOC-to-TOG factors and speciation profiles may be useful, particularly for analysis related to areas of very high methane emissions. Additionally, the EPA encourages the use of HAP emissions data when available to augment VOC speciation; therefore, we suggest using the inventory HAPs where criteria air pollutants (CAPs) and HAPs were provided by the same data source. When possible, the EPA's modeling platforms generally process the following HAPs rather than relying on VOC speciation: benzene, acetaldehyde, formaldehyde and methanol. These 4 HAPs are collectively known as "BAFM" and are removed from VOC speciation calculations for the remaining VOC HAPs needed for the air quality models. Ethanol can also be added to this "VOC integration" process where ethanol emissions are available. It is entirely up to the user to determine the "integration" status of specific sources in each inventory. A simple test for possible integration of VOC HAPs is the following. For each inventory unique source (i.e., a stack or nonpoint/mobile FIPS+SCC): 1) confirm that VOC HAPs and VOC were reported by the same data provider, and 2) compute VOC HAPs to ensure they are non-zero and less than inventory VOC. A detailed methodology is provided in section 3.2.1 of the [2011 emissions modeling platform technical support document](#).

County-specific speciation profile combinations are also available for cases where user-defined mixtures of two or more speciation profiles are needed. The "GSPRO_COMBO" feature in [SMOKE](#) can be applied by state and county and time period (e.g., month) and is currently used for on-road and nonroad mobile and gasoline-related stationary sources where the emissions sources use fuels with varying ethanol content (e.g., E0 and E10 profiles). Ethanol content varies spatially by state and county via nonattainment areas or local programs, temporally (e.g., during ozone season months), and by modeling year because future years have more ethanol. Certain source categories will require more careful review of speciation assignments. For example, the oil and gas sector (point, area and nonroad) inventories are generally constructed for specific drilling areas (i.e., drilling basins) which may include multiple counties with unique production gas characteristics. Knowledge of the type of gas (e.g., dry, wet, coal bed methane) or oil produced, flared and vented in these basin inventories is helpful for developing basin specific speciation assignments.

NO_x emission factors and, therefore, NO_x inventories are developed on a NO₂ weight basis. For air quality modeling, emissions processors must split NO_x to NO and NO₂ and in some cases HONO. Although emissions models allow using multiple speciation profiles for NO_x, historically only one split factor has been used of 90% NO and 10% NO₂. For mobile sources, the MOVES model calculates NO and NO₂ internally based on a more nuanced selection of factors and uses an NO₂ factor of 0.008 for onroad sources based on Sarwar (2008).

One additional NO_x speciation data resource is stack test data of NO/NO₂ ratios for use in AERMOD modeling for the 1-hr NO₂ standard. These data are available [here](#).

2.7.8.3 Spatial Allocation

For all source sectors that are compiled at a county resolution, the emissions models also need information about allocating the countywide emissions to individual grid cells that intersect the county boundaries. Such sectors include stationary area, nonroad mobile, and (non-link) on-road mobile sources. The spatial allocation process assigns fractions of county-total emissions to the model grid cells intersecting the county based on a “surrogate” data type (e.g., population, housing data). The appropriate types of surrogate data to use for each SCC in the inventories should be identified for this processing step. Spatial surrogates can be created using GIS to calculate the fraction of countywide emissions to allocate to each grid cell based on the surrogate type. These calculations can also be made using the [EPA’s Surrogate Tool](#), which is based on the Multimedia Integrated Modeling System (MIMS) Spatial Allocator. In addition, all SCCs needing spatial surrogates should be assigned a surrogate in a cross-reference file. Point sources do not need spatial surrogates, since the emissions models assign the grid location based on the latitude and longitude of the point sources. The EPA provides spatial surrogates and cross-references as part of its [latest modeling platform](#). The same spatial surrogate data are normally used in both the base and future year modeling. However, emissions developers can choose to alter the spatial surrogate data based on predicted changes in land use patterns, population growth, and demographics, although the impacts and utility of such approaches are not well characterized,²⁴ so their use needs to be well documented and explained.

2.7.8.4 Other Ancillary Inputs

On-road emissions for fine-scale model grids (e.g., 4-km grid cells or smaller) may be based on a link-based approach as mentioned in section 2.7.7.3. The VMT and speed data needed for a link-based approach can be provided using a Travel Demand Model (TDM). These models require their own sets of inputs, which depend on the specific TDM used. The MOVES Technical Guidance provides general guidance on the development of MOVES inputs. Details on using TDMs for link-based on-road mobile emissions are available from the EIIP document “[Use of Locality-Specific Transportation Data for the Development of Source Emission Inventories](#).” An example of the use of TDMs can be found in “[Use of Travel Demand Model Data to Improve Inventories in Philadelphia](#).”

²⁴ At the time this document was written, tools to readily predict future-year land use patterns are not readily available in a form for use in emissions modeling.

Emissions models have other input files that must be created. Previously, we noted that for point sources, emissions developers will have to identify which sources should be treated as elevated sources by an air quality model. To do this, data developers will select criteria such as stack height or a screening plume height value to allow an emissions model to flag point sources as elevated sources. In the SMOKE modeling system for example, the Elevpoint program can be used for this purpose.

The emissions models have a large number of files and settings which work together in fairly complex ways; therefore, users should be careful to select the appropriate files needed for the emissions model, and to prepare all input files in a way that will support using the emissions model for the specific air quality model application. A possible shortcut can be starting with the emissions modeling scripts included with the EPA's modeling platforms.

2.7.9 How Are Inventory Data Converted into Air Quality Model Input?

Emissions models are used to convert inventory data to inputs for air quality modeling. As described in section 2.7.8, as part of the emissions modeling process, additional ancillary data are needed to augment the raw emissions inventories. The emissions data for each of the six emissions sectors (point, area, on-road mobile, nonroad mobile, biogenics, and wildland fires) are temporally allocated, chemically speciated, and spatially allocated by the emissions model. The resulting hourly, gridded, and speciated emissions from all sectors are then combined before being used by an air quality model. In this section, we will provide information on several emissions models and summarize some key issues with the application of emissions models.

2.7.9.1 Emissions Models

Several emissions models are available for use in developing SIPs. While no single model has been specifically created for all situations, each model is generally capable of performing the necessary emissions processing steps including temporal, chemical, and spatial allocation. Users of such models are responsible for ensuring that the emissions processing steps transform the emission inventories as intended and are not changing the emissions in any unexpected way. Each model has different capabilities, limitations, and nuances. Therefore, when choosing an emissions model, it is worthwhile to discuss the choice with the developers of these systems and/or with EPA to determine which model is best suited for a particular application. Note that there are a number of programs that process emissions for individual source sectors. These are discussed below in the sector-specific subsections. Currently, SMOKE is the primary emissions

model used to develop emissions data for input into chemical transport grid models. Other emissions models can also be used, such as the Emissions Preprocessing System (EPS).

SMOKE supports processing of criteria, mercury, and toxics inventories for stationary point, stationary area, mobile, and biogenic emissions. This emissions model can create input files for the CMAQ and CAM_x air quality models. Applications of SMOKE have been presented at several of the International Emissions Inventory Workshops (Houyoux, 2000; Strum, 2003, Zubrow, 2012, Baek, 2010, Adelman, 2008, Baek, 2007a, Baek, 2007b, Baek, 2006, Eyth, 2006, Pouliot, 2005). SMOKE is available for UNIX and Linux operating systems, but is not recommended for use on PCs running Windows. It does not require third party software. The SMOKE software and User's Guide are available on the [SMOKE website](#).

Utilities for creating speciation profiles, biogenic land use, or spatial surrogates are not included within SMOKE. However, the Speciation Tool can create speciation profile inputs for SMOKE (Eyth, 2006), and biogenic land use and spatial surrogates can be built using the [MIMS Spatial Allocator Tool](#) along with the related Surrogate Tools.

2.7.9.2 Biogenic Emissions Models

There are several available biogenic emissions models that can be used to develop biogenic emissions for modeled attainment demonstrations and regional haze modeling. One such model is the [Biogenic Emissions Inventory System](#), version 3.6 (BEIS3.6) (Bash et al, 2016). This model can be run both as part of a CMAQ model run and alternatively as a module of the SMOKE system. The CMAQ approach is described [here](#). The latest documentation on the SMOKE approach to run BEIS is available [here](#).

Another biogenic model commonly used to support air quality model applications is the [Model of Emissions of Gases and Aerosols from Nature](#) (MEGAN). The MEGAN model also uses meteorological data including temperature and solar radiation as input to generate biogenic emissions. MEGAN is distributed with vegetation/land-use data that includes all of North America. Other biogenic emissions models have been used to support air quality modeling, such as [BEIGIS](#), which is a GIS-based biogenic emission model developed by the California Air Resources Board.

The BEIS modeling system uses land-use data from the Biogenic Emissions Land Use Database, version 4.1 (BELD4). [BELD4 data](#) provides data on the 230 vegetation classes at 1-km resolution over most of North America. These land use data can be created with the [MIMS Spatial Allocator](#). Based on inputs from the emissions developer, the Spatial Allocator will select the 1-km grid cells from the BELD data that intersect the modeling domain and (if necessary)

aggregate to the grid resolution of the modeling domain. Air agencies can alternatively rely on the EPA's 12-km gridded data for modeling domains that overlap with the EPA national domain, provided with the EPA's latest modeling platform on the [Emissions Modeling Clearinghouse](#).

In situations where air agencies consider biogenic emissions important for ozone, PM, or regional haze, the data used in these biogenic emission models could be updated to provide a better representation of vegetation and vegetation specific emission factors. For future-year modeling, land use data is typically held constant (same as the base case). Emissions developers can choose to change their land cover data based on predicted changes in land use patterns, however, the impact and utility of such approaches is not well characterized, so their use needs to be well documented and explained. Where fundamental changes are made to landuse/vegetation data or emission factors, those changes should be noted in the modeling protocol and/or final documentation package along with references to the source of updated/alternative data.

The meteorological data used as input to any biogenic emission model should be consistent with the data used for the air quality model. Biogenic emissions models are generally set up to use gridded hourly meteorological data, so inventory developers should be able to convert their meteorological inputs from air quality modeling inputs for use in their selected biogenics emissions model. Surface (or canopy level) temperature and solar radiation data can be obtained from modeled meteorological data, such as the WRF Model. Alternatively, solar radiation data could be obtained from satellite products.

Biogenic emission models evolve over time, so agencies using these models should evaluate the suitability of one model over the other as part of a modeling analysis. Once a choice has been made for modeling purposes, emissions should also be summed across the NAA for inclusion in the base year inventory for the NAA and/or the attainment projected inventory for the NAA.

2.7.10 Other Emissions Modeling Issues

In addition to the emissions modeling process and tools described above, there are several other important issues to consider. In the remainder of this section, we briefly address each of these issues.

2.7.10.1 Elevated Point Sources

Point sources need to be assigned to an appropriate model layer²⁵ (the vertical modeling dimension). Depending on the air quality model that is being used, different emissions modeling steps can be taken. Models such as CMAQ and CAM_x expect input emissions files separately for surface level emissions versus the elevated point-source emissions.

2.7.10.2 Treatment of ‘Atypical’ Sources of Emissions

In the NEI, there are several sources of emissions that are reported by only one state or a small number of states. These sources typically have very low emissions, so whether they are included in the modeling inventory typically has little impact on air quality modeling. Examples of these sources include domestic and wild animal waste emissions (primarily NH₃), human perspiration and cigarette smoke, and swimming pools. In some inventories, large catastrophic/accidental releases are reported (e.g., car accidents, tire fires). It is generally considered inappropriate to include these sources in emissions processing for air quality models. However, some source categories may be important or unique to a particular area. Before removing seemingly unimportant source categories, the relative importance (e.g., as a percentage of emissions in the area) of each category should be evaluated.

Air agencies should also review and consider the draft EI SIP Guidance and the Ozone Implementation Rule regarding EGU emissions during High Electric Demand Day (HEDD) periods. Such emissions can be crucial for having a complete understanding of relevant emissions sources within a modeling domain. Where these emissions are important for assessing a nonattainment problem, air agencies should consider the potential impact of HEDD emissions when selecting time periods (e.g., episodes, season, year) to model.

2.7.10.3 Transport and Meteorology-based Reductions in Fugitive Dust Emissions

Fugitive dust emissions are another large source of primary PM_{2.5} emissions. However, past modeling experience has shown modeled PM_{2.5} concentration over-predictions from these emissions (Pouliot et al, 2010). Therefore, the EPA recommends reducing area-source fugitive dust emissions prior to air quality modeling to account for “capture” by the terrain (such as deposition on vegetation and buildings), changes in the emissions potential (such as frozen ground), and removal by meteorology (such as precipitation). These two components should be accounted for when adjusting the inventory PM emissions from PM sources such as paved and unpaved roads, construction, mining, agricultural activities, and industrial dust and other low-

²⁵ Point sources generally comprise most of the elevated emissions (above layer 1), although other sources, such as fires, ships, and aircraft may also have emissions assigned to elevated layers.

level fugitive dust source categories. The “captured” portion of the reduction can be based on gridded land use data such as vegetation and building characteristics. The EPA has developed a methodology within SMOKE to adjust the fugitive dust emissions. The “meteorological” component of the reduction requires intermediate SMOKE processing scripts to merge hourly, gridded precipitation data and snow cover values to zero-out all fugitive dust emissions where appropriate. To avoid double-counting the precipitation-based reduction, the user should make sure that the inventory fugitive dust inventory does not already include a “MET-adjusted” reduction prior to these manipulations. This combined transport and met-based reduction approach is documented in Pouliot et al., 2010.

2.7.10.4 Quality Assurance

Quality assurance (QA) is a key component of any successful emissions modeling effort. A brief synopsis of appropriate QA approaches for emissions modeling is available in section 2.20 of the [SMOKE manual](#). The purpose of QA for emissions modeling is to ensure that the inventories are correctly processed using the information the modeler intended. (It is assumed here that the inventory itself has already been QA’d and erroneous values and/or outliers removed through inventory QA procedures, as described in the EI SIP Guidance.)

Emissions modeling QA includes such activities as:

- Reviewing log files for errors and warnings and addressing problems;
- Comparing emissions between each of the processing stages (e.g., data import, speciation, temporal allocation) to ensure mass is conserved;
- Checking that the correct speciation, temporal allocation, and spatial allocation factors were applied; and
- Reviewing the modeling-specific parameters such as stack parameters.

It is also useful to compare air quality modeling-ready emissions summaries to previous emissions modeling efforts to verify expected emissions changes by source category(s) and geographic area(s) of interest. In addition, the process of running emissions inventories through emissions models and air quality models often provides insights into the emission inventories themselves. These insights can lead to inventory changes that improve the quality of inventories for additional modeling iterations.

In general, this guidance also encourages the use of graphical analysis and GIS for improved QA of emissions data and processing. A commonly used analysis tool for model-ready emissions data is the EPA-sponsored Visualization Environment for Rich Data Interpretation (VERDI) tool. The VERDI software package provides for efficient, flexible and modular capabilities of

overlaying meteorology, emissions and air quality modeling data with GIS shapefiles. More information on VERDI is available on the [VERDI website](#).

2.7.11 How Are Emissions Estimated for Future Years?

Emissions estimates for future years are called “emissions projections.” The inventory developed for modeled attainment demonstrations is called the *attainment projected inventory for modeling*.²⁶ These emissions projections include emissions changes (due to increased or decreased activities), facility and/or unit-level shutdowns, and emissions controls (which can be due to, among other things, regulations, settlements or fuel-switching that reduce emissions in specific ways in the future). The goal in making projections is to obtain a reasonable estimate of future-year emissions that accounts for the key variables that will affect future emissions. Each air agency is encouraged to incorporate in its analysis the variables that have historically been shown to drive the economy and emissions within the modeling domain, as well as the changes in growth patterns and regulations that are expected to take place between the time of the base year and future years.

Complete guidance on emissions projections is provided in the EI SIP Guidance, with subsections on EGUs, non-EGU stationary sources, on-road mobile sources, nonroad mobile equipment, other nonroad mobile sources, and a list of other projection resources. The EI SIP Guidance includes a lengthy discussion about considerations that should be made for models or other tools that forecast EGU emissions. As noted in that guidance, “the states are advised to make sure that the tools meet the criteria laid out in this document because EPA will use these criteria to assess any EGU projection information submitted as part of SIPs.” In addition, several additional issues are listed here for consideration for modeling inventories.

Emissions models (e.g., SMOKE, EPS) provide the capability to create future-year inventories using base year inventories and projection information. Emissions modelers will need to convert the projection data into specific formats for input to these models. Inventory developers should determine which emissions model will be used to perform the calculations and make sure that the type(s) of information needed by the model is being collected.

In the context of modeling for ozone and PM_{2.5} purposes, for fires, it is recommended that the base year fires be held constant for use in the future year modeling. This approach allows for

²⁶ The name applies even if it turns out that the modeling shows that the area is not able to attain the standard by the latest applicable attainment date. Note that projected inventories are also used for regional haze modeling, however, the name “attainment projected inventory for modeling” applies specifically to attainment demonstrations.

the impact of these fires to be minimized using the RRF approach, while still including realistic fire patterns that are relevant to ozone and PM_{2.5} formation necessary for modeled attainment demonstrations. States have flexibility in how they estimate base year fires, but it is recommended that states should hold these constant in the future modeling case. Additional specific discussion of future-year fires as they relate to PM_{2.5} SIPs is available in section IV.D.3.b of the preamble to the PM_{2.5} SIP Requirements Rule. For regional haze purposes, air agencies should consult sections IV.E and IV.G of the 2017 Regional Haze Rule, 82 FR 3078 (Jan. 10, 2017), as well as their Regional EPA office as appropriate, to develop an approach for the treatment of emissions from fires.

Ancillary input files for inputs to emissions models, such as spatial surrogates, temporal allocation factors and especially speciation profiles may also need to be adjusted to reflect conditions expected in the future. The EPA modeling platforms, for example, consider the impact on speciation of fuels used in the future, which are expected to change over time due to regulations.

Once a future-year inventory and other data have been created, it should undergo the same steps as for the base-year modeling, including temporal allocation, speciation, spatial allocation, elevated source selection, special on-road mobile processing, any other custom processing steps (e.g. applying meteorology-based information to fugitive dust, agricultural NH₃ and residential wood combustion), and QA. Except where intentional, every attempt should be made to use consistent approaches between the future year and the base year for all of these modeling steps. Inconsistencies in approaches between the future-year modeling and the base-year modeling can lead to artificial differences in air quality modeling results that can affect conclusions.²⁷ Therefore, it is critical to avoid such differences whenever possible. If inconsistent base and future year approaches are necessary, they should be well documented and explained.

2.8 Initial and Lateral Boundary Conditions

Air quality models require chemical time and space boundary conditions in order to solve for concentrations within the modeled domain and time period. The time boundary or *initial condition* (IC) is provided at the beginning of the first simulated time step and the space boundary or *lateral boundary condition* (LBC) is provided at the outer edge of the modeling domain. As with other model inputs, the establishment of the IC and LBC data should be guided

²⁷ This is especially important due to the use of the “relative” change in modeled concentrations as part of the modeled attainment test. An inconsistency in base and future year emissions may lead to a very large modeled percent change in ozone and/or PM_{2.5} concentrations.

by the conceptual model of the air quality issue being simulated. For instance, more attention will be needed in developing accurate LBC for cases in which ambient data analyses (or previous modeling scenarios) have indicated the potential for long-range transport of pollutant material, compared to cases in which the air quality problem has been identified as largely local in nature. Numerous studies have highlighted the importance of accurately representing LBC in optimizing model performance and identifying the most effective path to attaining the NAAQS (Jacob *et al.*, 1999; Tang *et al.*, 2009; Hogrefe *et al.*, 2011).

Given limitations in available ambient data, it is impossible to exactly specify the complex three-dimensional chemical characteristics of the IC or LBC. As a result, two basic approaches to establishing these fields have been used within the modeling community. The first and preferred approach is to characterize the IC/LBC data as accurately as possible given the existing state of knowledge about ambient conditions at those times and in those locations. The second approach is to attempt to minimize the impacts of the IC and LBC by configuring the domain and modeling period such that the air quality concentrations in the locations and times of interest are largely unaffected by the IC/LBC inputs.

The impacts of the IC are most easily minimized when they are reasonably accurate. In most cases, it will be possible to minimize the impacts of the IC data via the use of a model “spin up” period. A spin up period is defined as some number of modeling days that precede the time period of actual interest. The model outputs for this spin up period are discarded from any analytical post-processing and evaluation, as they are potentially affected by the uncertain initial conditions. The length of the needed model spin-up period will vary as a function of: the domain size, prevailing meteorological conditions, and the chemical lifetimes of the pollutants being simulated. It is a simple modeling exercise to test the sensitivity of the key time periods to the initial conditions. Previous sensitivity modeling has determined that the IC are typically “washed out” of the system in as few as 3-5 days for a local-scale modeling analysis; approximately 10-20 days for a regional-scale analysis; and on the order of 6 months or more for a hemispheric-scale analysis (Berge *et al.*, 2001; U.S. EPA 2010; Anenberg *et al.*, 2011). More recent work shows that 2 weeks is generally sufficient to reduce IC influence to under 1%, with more realistic IC decreasing the spin-up time (Hogrefe *et al.*, 2017). Upper air (elevated layers in the model) takes longer to minimize the influence of IC, and as a result, some locations may require longer spin-up). If there is any question as to the appropriate length of the spin-up period, then sensitivity modeling tests should be conducted. Otherwise, the above guidelines should be sufficient for most ozone and PM_{2.5} attainment demonstrations and regional haze assessments.

In many cases, it will not be feasible to build a large enough domain to minimize the impacts from emissions outside the domain. For these cases, it will be necessary to downscale the requisite species concentration data from well-performing, coarser-grid, larger domain modeling runs. (In rare cases, it may be possible to assign LBC from detailed field study species data, but most domains will not have complete chemical profiles in space and time along the domain edges.). These larger “parent” grids may be generated by the same regional scale model at coarser resolution; or they can be generated via global or hemispheric models. In the last decade, several global/hemispheric air quality models have been used to generate regional LBC inputs. A sample of models used for LBC include: GEOS-Chem (Bey et al., 2001), the AM3 atmospheric component of the GFDL global coupled model (Donner, et al., 2011), the Model for Ozone And Related Tracers (MOZART, Emmons et al., 2010), the WRF-Chem model (Zhang, et al., 2012a), and the hemispheric CMAQ model (Byun and Schere, 2006; Fu et al., 2012). The EPA does not recommend any one particular global/hemispheric model. Each regional modeling exercise should individually assess whether the chosen global/hemispheric or coarse regional model accurately captures lateral boundary conditions.

For cases in which the LBC will be extracted from larger-scale regional/hemispheric modeling, the EPA recommends two efforts to optimize the LBC characterizations. First, modelers should try to minimize any disconnects in the downscaling process. Wherever possible, one should attempt to utilize the same species, chemical mechanism, layer depths, and meteorological inputs in the regional/hemispheric model as are being used in the finer-scale attainment demonstration modeling (Lam and Fu, 2009). This will minimize the number of uncertain translations needed to convert coarse-scale outputs to finer-scale LBC inputs. In particular, careful consideration of the stratosphere in the two modeling systems will be needed to ensure that regional/hemispheric ozone that is stratospheric in origin is not excessively mixed down to the surface in the finer-scale modeling due to disconnects between the two systems.²⁸ Second, there should be a comprehensive evaluation of the regional/hemispheric model performance (Bey *et al.*, 2001). While there may not be a detailed data set available for model evaluation along the domain lateral boundaries in most cases, consideration of model performance across the domain will provide a first-order indication of the ability of the coarser-scale model to characterize air quality at the boundaries. Additionally, it may also be possible to infer

²⁸ In establishing the layer structure for both global and regional models, it is advisable to avoid selecting upper model layers that span both the upper troposphere and lower stratosphere. It has been seen that “hybrid” layers can allow for inappropriate diffusive mixing between those two generally decoupled sections of the atmosphere. In cases where stratospheric intrusions are not expected to influence ozone in the area, it may be appropriate to artificially cap stratospheric ozone concentrations to avoid ozone performance issues. This should be a “last resort” fix, only applied after detailed assessments of the vertical diffusion and vertical advection schemes within the model.

information about the quality of the coarse-model estimates via comparisons with satellite data (Liu *et al.*, 2006, Henderson *et al.*, 2013).

In some situations, it may be possible to construct a modeling platform in which the LBC will not substantially influence the air quality issue under consideration. For instance, areas for which there is no evidence of pollutant transport from the far edges of the model domain to the local area may be able to demonstrate that the determination of LBC data will not impact the eventual modeling demonstration. As with the IC data, this conclusion can be proven via simple sensitivity tests in which the LBC are modified from a base state and the results between the two runs are compared (e.g., Appel *et al.*, 2007). For situations in which alterations to the LBC data will not impact key findings, it is acceptable to use time-invariant profiles for LBC. Because there are many publicly available sources of modeled boundary conditions, this approach should only be used only when there is good reason.

Due to the potential impact of LBCs on model response to emissions controls, it is important to accurately characterize the relative influence of LBC versus local emissions. For example, if the impacts of LBC on local air quality are overestimated, it will be more difficult than it otherwise should be to show reductions in future design values from local controls. Conversely, if the modeling system underestimates the role of inflow air quality, local emissions reductions may appear more effective in the model than they will be in reality.

The selection of future year LBCs also has potentially important ramifications on the relative response factors derived from the modeling for the various control scenarios. If LBC are known to impact local air quality, then modelers may need to consider how these contributions will change between the base year and the attainment year (Adelman *et al.*, 2011). Ambient trends analyses for 1990-2010 have indicated that free tropospheric ozone levels above the western U.S. have increased by approximately 0.5 ppb/year over those two decades with increases seen at rural surface monitors in the west (Cooper *et al.*, 2012; Cooper *et al.*, 2010; Lin *et al.*, 2017). More recent analysis focusing on 2000-2016 shows mixed trends in the free troposphere with only one high altitude surface monitor with a significant increase in its median or 95th percentile concentration. The most recent trends may suggest decreasing future ozone contributions from LBC due to international controls (e.g., van der A *et al.*, 2017). It is left to the discretion of the air agency to determine whether varying future LBC are needed as part of an attainment demonstration. Updated future boundary conditions may be needed when emissions changes are expected outside the domain that will meaningfully change the LBC and impact the area(s) of interest within the domain. This decision should consider both the length of the projection period and the potential for significant air quality changes outside the modeling domain. Additionally, careful consideration of upstream emissions will be needed as

part of any additional future-year regional/hemispheric modeling conducted to develop future LBC. If updated future year LBC are used, those data should be fully described and justified in the modeling protocol.

3.0 Evaluating Model Performance

3.1 Overview of Model Performance Evaluation

The results of a model performance evaluation (MPE) should be considered prior to using modeling to support an attainment demonstration or regional haze assessment. The objective of the MPE is to demonstrate that the base case model can simulate observed pollution concentrations during historical pollution episodes, and to develop confidence that the model can reliably predict how future pollution levels will change in response to changes in emissions. A particular concern in photochemical models is that compensating errors in the model can cause the model to reproduce observed pollution concentrations in the base case while incorrectly representing the emissions, dispersion and chemistry processes that control pollution formation. Models that achieve good performance through compensating errors may not be reliable for predicting how pollution levels will respond to future emissions reductions. However, if an operational evaluation is conducted over a large enough spatial and temporal scale to incorporate a variety of meteorology and emissions conditions, good model performance is less likely the result of compensating error. Thus, a key goal of the MPE is to demonstrate that the model is getting good results for the right reason (Russell and Dennis, 2000) and to show that the model is able to capture pollution concentrations over the range of conditions that are relevant for the regulatory application being undertaken. In addition, the MPE can provide air agencies with tools to identify and fix causes of poor model performance such as problems in the meteorological, emissions, or boundary condition input files.

Dennis et al. (2010) describe an MPE framework that includes four different approaches that can be used to evaluate air quality models:

1. Operational evaluation techniques include statistical and graphical analyses aimed at determining whether the modeled simulated variables are comparable to measurements.
2. Diagnostic evaluation focuses on process-oriented analyses that determine whether the individual processes and components of the model system are working correctly, both independently and in combination.
3. Dynamic evaluation assesses the ability of the air quality model to predict changes in air quality given changes in source emissions or meteorology, the principal forces that drive the air quality model.
4. Probabilistic evaluation attempts to assess the level of confidence in the model predictions through techniques such as ensemble model simulations.

The goal of the operational evaluation is to determine how well the model replicates observed concentrations of PM_{2.5} components, ozone and their precursors. Diagnostic and dynamic evaluations are used to determine whether the model accurately represents the processes that determine pollutant concentrations, including emissions, dispersion, chemical reactions, and deposition (i.e., to determine if the model is getting good results for the right reason). For cases in which the model performs poorly in the operational evaluation, the diagnostic and dynamic evaluation can provide insights into the causes of the poor performance and to improve model performance. Ultimately, the goal of these evaluation methods is to assess the degree of confidence in the use of the model as a tool to inform the planning process, and more specifically, to determine how reliably the model predicts the response of ozone and/or PM_{2.5} to changes in emissions. The modeled attainment and regional haze tests use models to predict the response of ozone and/or PM_{2.5} to changes in emissions and then applies the resulting relative response factors (RRFs) to observed (rather than modeled) ambient data. Thus, while historically, most of the effort has focused on the operational evaluation, the relative test makes the diagnostic and dynamic evaluation also important.

At a minimum, a model used for air quality planning purposes should include a complete operational MPE using all available ambient monitoring data for the base case model simulation period. Section 3.2 describes the types of metrics and plots that are typically developed as part of an operational MPE, and section 3.3 describes ambient data that is available through continuously operating monitoring networks. If available, monitoring data from special field studies and other research data may also be used in the operational MPE.

Where practical, the MPE should also include some level of diagnostic evaluation. The use of sensitivity studies, process analysis, indicator ratios and source apportionment approaches for diagnostic evaluation, including dynamic and probabilistic evaluations are described in section 3.4. Given that air agencies might have limited resources and time to perform diagnostic and dynamic evaluation, the use of these methods may be limited in scope in a typical regulatory modeling application. However, more comprehensive diagnostic testing of the model can be a valuable component of the weight of evidence analysis used to support a SIP model attainment demonstration.

From an operational standpoint, the EPA recommends that air agencies compare their evaluation results against similar modeling exercises to ensure that the model performance approximates the quality of other applications. Recent literature reviews (Simon et al, 2012; Emery et al., 2017) summarize photochemical model performance for applications published in the peer-reviewed literature between 2006 and 2012. These reviews may serve as a resource for identifying typical model performance for state of the science modeling applications. It is clear that there is no single definitive test for evaluating model performance. All of the tests

mentioned here have strengths and weaknesses. Further, even with a single performance test, it is not appropriate to assign “bright line” criteria that distinguish between adequate and inadequate model performance. In this regard, the EPA recommends that a “weight of evidence” approach be used to determine whether a particular modeling application is valid for assessing the future attainment status of an area. The EPA recommends that air agencies conduct a variety of performance tests and weigh them qualitatively to assess model performance. Provided suitable databases are available, greater weight should be given to those tests which assess the model capabilities most closely related to how the model is used (i.e., tests that provide insight into the accuracy of the model’s relative response to emissions reductions should be given more weight). Generally, additional confidence should be attributed to model applications in which a variety of the tests described here are applied and the results indicate that the model is performing well.

3.2 Operational Evaluation

An operational evaluation is used to assess how accurately the model predicts observed concentrations. The underlying rationale is that if we are able to correctly characterize historical concentrations of ozone, PM and their precursors for a variety of meteorological conditions, this gives us some confidence that we can correctly characterize future concentrations under alternative emissions levels. Typically, this type of evaluation is comprised of statistical assessments of modeled versus observed data. Operational evaluations are generally accompanied by graphical and other qualitative descriptions of the model's ability to replicate historical air quality patterns. An operational evaluation provides a benchmark for model performance and can therefore identify model limitations and uncertainties that may require further model development/improvement and/or diagnostic evaluation

The robustness of an operational evaluation is directly related to the amount and quality of the ambient data available for comparison. An operational evaluation for ozone would ideally include co-located measurements of ozone precursors NO_x and VOC and vertical profile measurements that can be used to determine the extent of vertical mixing of pollutants and the concentration of ozone and precursors above the boundary layer.

An operational evaluation for PM_{2.5} and regional haze is similar to that for ozone; however, an important difference is that PM_{2.5} consists of many component species and is typically measured with a 24-hour averaging time. The chemical components of PM_{2.5} should be evaluated individually. In fact, in undertaking an operational assessment, it is more important to evaluate the components of PM_{2.5} than to evaluate total PM_{2.5}. Apparent “good performance” for total PM_{2.5} does not indicate whether the model is predicting the proper mix of components, which is important for the modeled attainment test or regional haze

assessment. If performance of the major components is good, then it follows that performance for total PM_{2.5} will also be good. In addition to measurements of VOC and NO_x, which are precursors for organic aerosols and nitrate, a PM_{2.5} model evaluation should also include measurements of gaseous precursors SO₂ and (where available) NH₃. Due to the influence of initial conditions, model predictions from the spin-up days should be excluded from the analysis of model performance.

3.2.1 Metrics

Operational evaluations quantify model performance through a variety of statistical metrics. Recommended metrics are described below and shown in Table 3.1. It is important to include multiple statistical measures in any operational evaluation to fully characterize model performance. At a minimum, we recommend evaluating: Mean Observed, Mean Model, Mean Bias, Mean Error and/or Root Mean Square Error, Normalized Mean Bias and/or Fractional Bias, Normalized Mean Error and/or Fractional Error, and the correlation coefficient. The equations for calculating each of these metrics are given in Table 3.1.

Mean Observed: The time-averaged mean observed value (in ppb or $\mu\text{g}/\text{m}^3$).

Mean Model: The time-averaged mean predicted value (in ppb or $\mu\text{g}/\text{m}^3$) paired in time and space with the observations.

Mean Bias (MB): This performance statistic averages the model/observation residual paired in time and space. A value of zero would indicate that the model over-predictions and model under predictions exactly cancel each other out. This metric is reported in the unit of measure (ppb or $\mu\text{g}/\text{m}^3$).

Mean (Gross) Error (ME/MGE): This performance statistic averages the absolute value of the model/observation residual paired in time and space. A value of zero would indicate that the model exactly matches the observed values at all points in space/time. This metric is reported in the unit of measure (ppb or $\mu\text{g}/\text{m}^3$).

Root Mean Square Error (RMSE): This performance statistic (in units of ppb or $\mu\text{g}/\text{m}^3$) is a measure of the average distance between predicted and observed values. It is calculated as the standard deviation of the difference between modeled and observed values.

Normalized Mean Bias (NMB): This statistic (given in units of percent) is used to normalize MB to the average observed value. NMB values range from -100% to +infinity. Consequently, negative and positive bias values using this metric are not symmetrical around 0.

Normalized Mean Error (NME): This performance statistic (given in units of percent) is used to normalize the mean error relative to the average observation. This statistic averages the

absolute value of the difference (model - observed) over the sum of observed values. NME values range from 0 to +infinity.

(Mean) Fractional Bias (MFB/FB): Fractional bias is determined by normalizing the MB by the average of observed and modeled concentrations. The range of FB is -200% to +200%. The fractional bias for cases with factors of 2 under- and over-prediction are -67 and + 67 percent, respectively (as opposed to -50 and +100 percent, when using normalized bias). Fractional bias equally weights positive and negative bias estimates (underestimates and overestimates are symmetrical around 0).

(Mean) Fractional Error (MFE/FE): Fractional error is determined by normalizing the ME by the average of observed and modeled concentrations. The range of values for FE is 0 to 200%. It is similar to the fractional bias except the absolute value of the difference is used so that the error is always positive.

Correlation Coefficient (r) and Coefficient of Determination (R²): These performance statistic measures the degree to which two variables are linearly related. A correlation coefficient of 1 indicates a perfect linear relationship; whereas a correlation coefficient of 0 means that there is no linear relationship between the variables. A correlation coefficient of less than 0 indicate anti-correlation. The Coefficient of Determination is always positive.

Table 3.1: Definitions of recommended statistical metrics

Abbreviation	Term	Definition
MB	mean bias	$\frac{1}{N} \sum (M_i - O_i)$
ME	mean error	$\frac{1}{N} \sum M_i - O_i $
RMSE	root mean squared error	$\sqrt{\frac{\sum (M_i - O_i)^2}{N}}$
FB	fractional bias	$100\% \times \frac{2}{N} \sum \frac{(M_i - O_i)}{(M_i + O_i)}$
FE	fractional error	$100\% \times \frac{2}{N} \sum \frac{ M_i - O_i }{(M_i + O_i)}$
NMB	normalized mean bias	$100\% \times \frac{\sum (M_i - O_i)}{\sum O_i}$

NME	normalized mean error	$100\% \times \frac{\sum M_i - O_i }{\sum O_i}$
r	Correlation coefficient	$\left(\frac{\sum_1^N (M_i - \bar{M}) \times (O_i - \bar{O})}{\sqrt{\sum_1^N (M_i - \bar{M})^2 \sum_1^N (O_i - \bar{O})^2}} \right)$
r ²	coefficient of determination	$\left(\frac{\sum_1^N (M_i - \bar{M}) \times (O_i - \bar{O})}{\sqrt{\sum_1^N (M_i - \bar{M})^2 \sum_1^N (O_i - \bar{O})^2}} \right)^2$

M_i = modeled concentration i. O_i = observed concentration i. N = number of paired obs/model concentrations. $\bar{M}$ = mean modeled concentration. $\bar{O}$ = mean observed concentration.

Observations and model predictions should initially be paired in time and space, matching the temporal resolution of the raw observation data. When matching in time, modelers should pay special attention to making sure that monitor and model data are both in local standard time. The units of time associated with model and observed concentrations can be 24-hour (usually for PM and its species), hourly (usually for species with continuous measurements, like ozone), or sometimes weekly (such as for CASTNet filter pack measurements). Temporal averaging is appropriate when used to match a relevant regulatory metric such as maximum 8-hr daily average ozone. As appropriate, air agencies should then aggregate the raw statistical results into meaningful groups of sub-regions or sub-periods. For example, examining model performance within and near the non-attainment area(s) of interest may be more important than performance in other parts of the modeling domain. For larger areas with more spatial variation, it may also be informative to evaluate sub-regions within the non-attainment area. In addition to any spatially aggregated statistics, model performance should also be evaluated at individual monitors within the nonattainment area. Similarly, priority may be placed on examination of the days that are potentially used in the attainment test (i.e., base period days with 8-hour ozone > 60 ppb). That is not to say that model performance evaluations should ignore performance on lower ozone days or in areas outside of the nonattainment areas. Model performance on lower concentration days and in areas outside of the nonattainment area are still important, but it is appropriate to give more attention to the model outputs that most directly impact the outcome of the attainment test. Unlike attainment demonstrations, model performance on days with low concentrations may be especially important for regional haze analyses. Some IMPROVE sites routinely measure extremely low PM species concentrations (even on the most impaired days).

In terms of pairing model predictions with monitored observations, the EPA recommends that the grid cell value in which the monitor resides be used for the calculations. It would also be acceptable to consider bi-linear interpolation of model predictions to specific monitoring

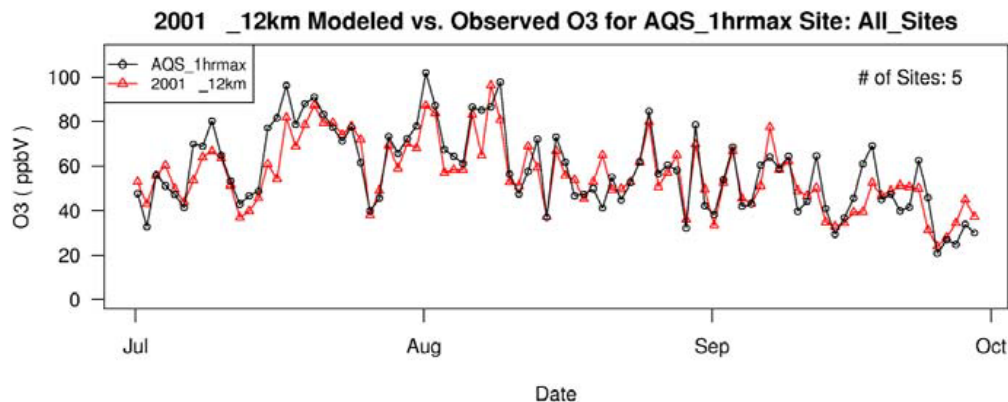
locations.²⁹ Air agencies should recognize that, even in the case of perfect model performance, model-observed residuals are unlikely to result in exact matches due to measurement uncertainty and differences in the spatial extent represented by model predictions, which are volume averages, and the observations, which are point values.

3.2.2 Plots

In addition to statistical summaries, graphical displays of data allow for a fuller characterization of model performance. Therefore, plots play a key role in any model performance evaluation. Below are examples of some types of plots which have been useful in past evaluations.

Time series plots of model and predicted hourly and/or daily concentrations (e.g., maximum 1-hour average, maximum 8-hour average, or 24-hour average) for each monitoring location in the nonattainment area, as well as key sites outside of the nonattainment area. These plots are especially important for examining performance at individual monitors and show how well the model captures temporal variations in pollutant concentrations at individual locations. Time series plots can indicate if there are particular times of day or days/episodes when the model performs especially poorly.

Figure 3.2.1 Example time series plot of daily 1-hour maximum ozone concentrations

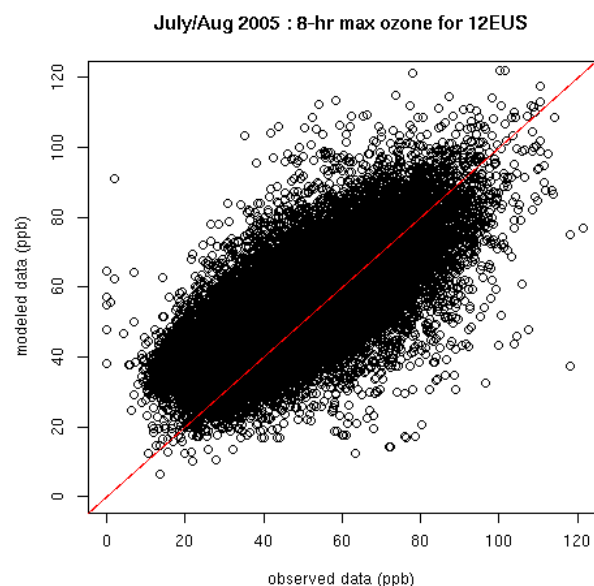


Scatter plots of predicted and observed concentrations at each site. These plots are useful for indicating if there is a particular part of the distribution of observations that is poorly

²⁹In certain instances, air agencies may also want to conduct performance evaluations using a “near the monitor” grid cell array (i.e., the best match within a 3X3 grid cell array centered on the monitor). A “near the monitor” analysis may be useful when strong ozone gradients are observed, such as in the presence of a sea breeze or in strongly oxidant limited conditions.

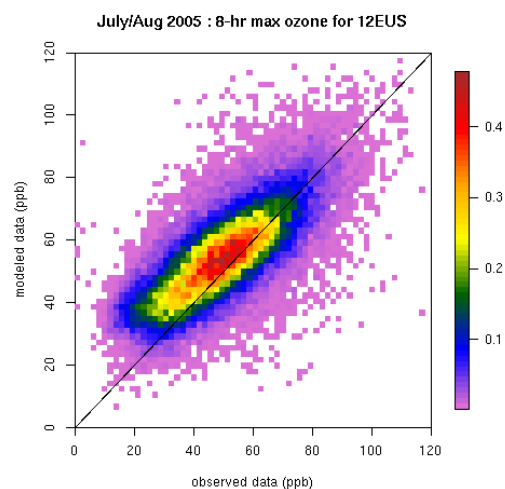
represented by the model. It may also be useful to develop separate plots for individual time periods or key sub-regions.

Figure 3.2.2 Example scatter plot of 8-hour daily maximum ozone concentrations



Density plots are a variation on scatter plots which are especially useful with large amounts of data when individual points overlap on a scatter plot. Density plots color code each point on the scatter plot based on the number of points falling in that location.

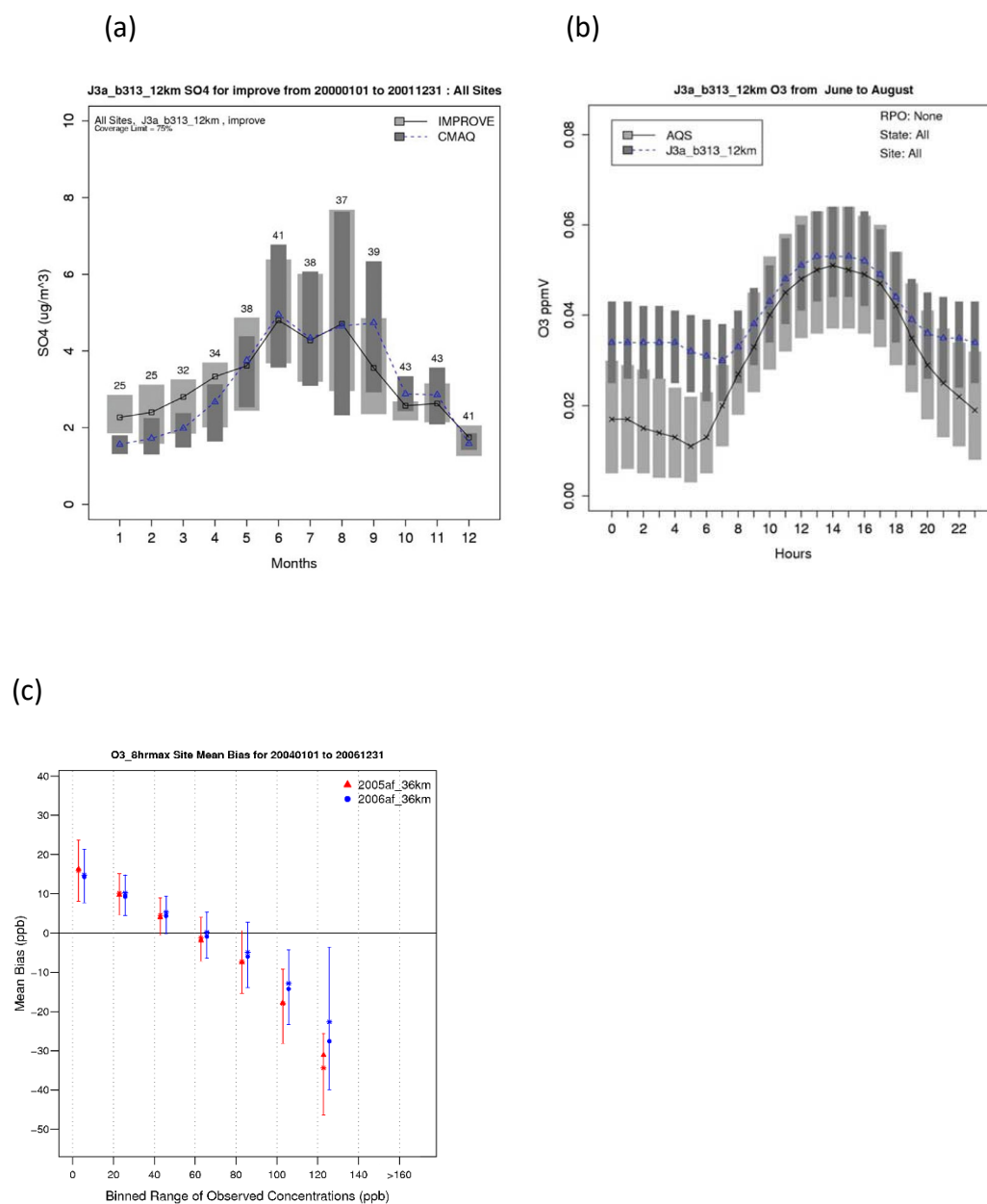
Figure 3.2.3 Example density plot of 8-hour daily maximum ozone concentrations



Box plots can be developed for model performance evaluation. These types of plots show the distribution of observations, model estimates, or performance metrics, which can be grouped

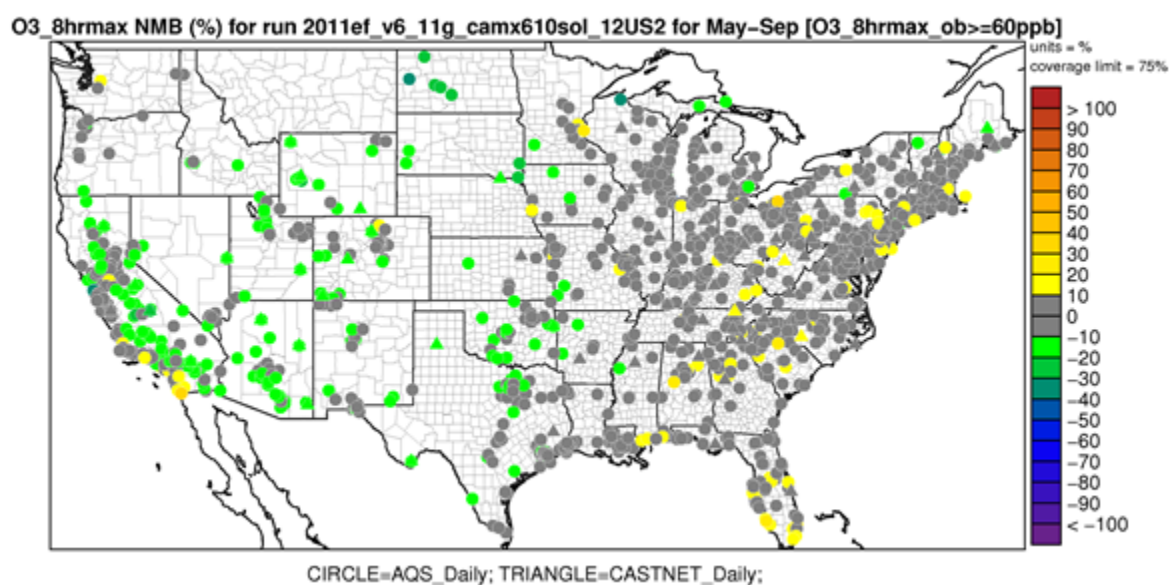
in a variety of ways, most commonly by observed ozone concentration, month, or hour of the day. Box plots can show several quantities: the 25% to 75% percentiles, the median values, and outliers. The monthly box plot can be used to quickly visualize model performance across the entire year, highlighting the seasonal change in model performance. The hourly or “diurnal” box plot is constructed using hourly data, and shows how the model predictions compare against observations throughout an entire day.

Figure 3.2.4 Example box plots of (a) monthly average sulfate concentrations, (b) daily diurnal average ozone concentrations, and (c) seasonal ozone bias binned by concentration range



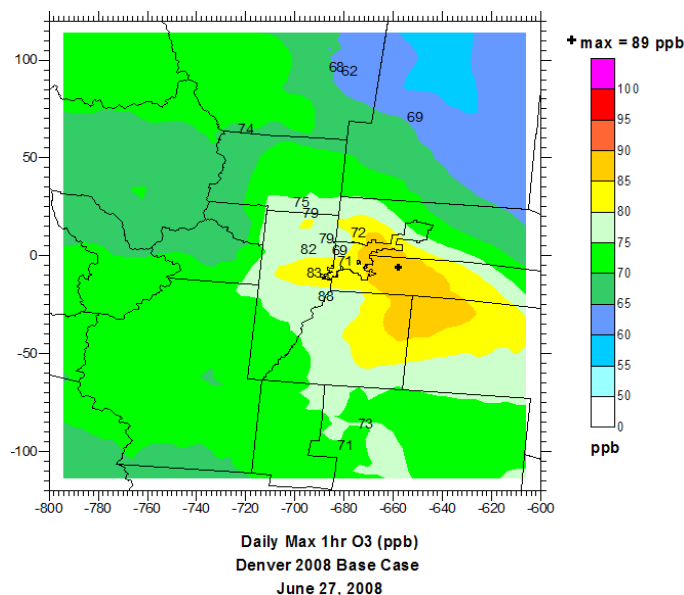
Spatial plots of model performance at monitor locations provide an overall picture of the geographic patterns in model performance. Any performance metric can be plotted in this manner, but it is most common to include spatial plots of MB, ME, NMB, and NME. Spatial plots of correlation may also be useful. These plots are most useful when constructed on a monthly or seasonal basis. For ozone these plots may be constructed to include all days or only “high ozone days.” For regional haze, these plots may be constructed to include only the 20% most impaired days or 20% clearest days.

Figure 3.2.5 Example of spatial plot of NMB at monitor locations for days with O₃ above 60 ppb during the 2011 ozone summer season (May-September).



Daily gridded tile plots of predicted concentrations across the modeling domain with the actual observations as an overlay. Plots should be prepared for relevant averaging time (i.e., 1-hour maxima, daily 8-hour maxima, 24-hour average, etc.). These plots can reveal locations where the model performs poorly. Superimposing observed concentrations on the predicted isopleths reveals useful information on the spatial alignment of predicted and observed plumes.

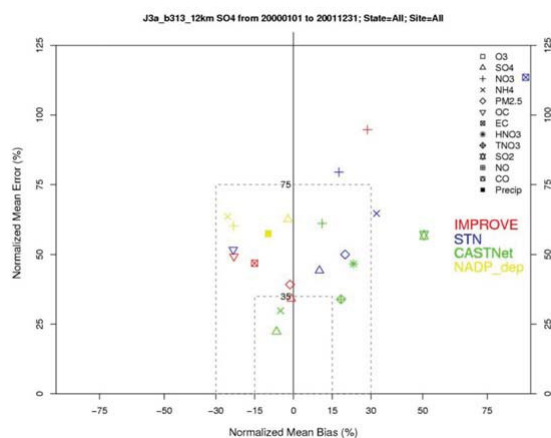
Figure 3.2.6 Example gridded tile plot of daily maximum 1-hour ozone concentrations (with overlaid observations)



Animations of predicted hourly concentrations for all episode days or for certain periods of interest. Animations are useful for examining the timing and location of pollutant formation. Animations may also reveal transport patterns (especially when looking at aloft layers). Animations can also be used to qualitatively compare model outputs with the conceptual model of particular pollution episodes. These plots may also reveal whether an important feature was simulated but was spatially or temporally displaced.

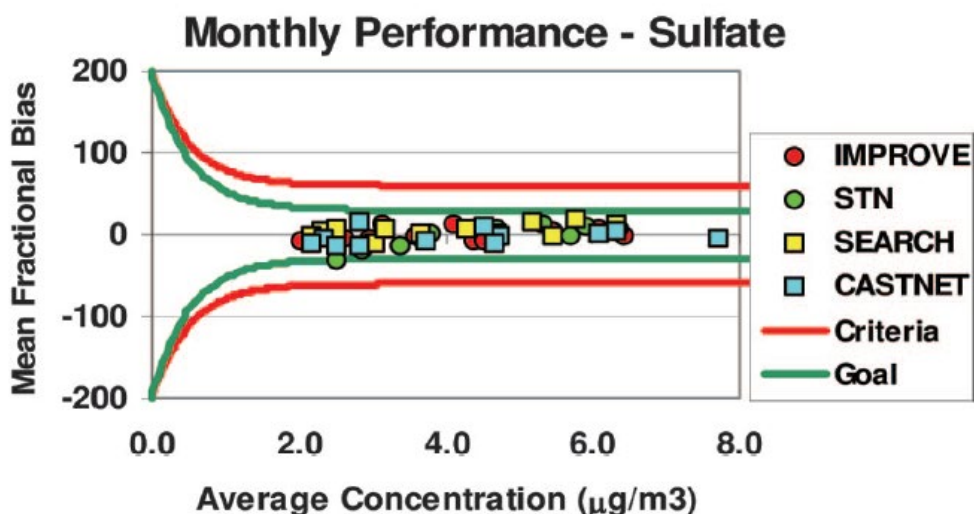
The soccer plot (Tesché et al, 2006) is so named because the dotted lines illustrating performance goals resemble a soccer goal. The plot is a convenient way to visualize model performance of both bias and error on a single plot. As bias and error approach zero, the points are plotted closer to or within the “goal,” represented by the dashed boxes.

Figure 3.2.7 Example soccer plot of sulfate normalized mean bias and error.



The bugle plot (Boylan and Russell, 2006; Tesche et al., 2006), named for the shape formed by the criteria and goal lines, is another plot available for model performance evaluation. The bugle plots are shaped as such because the goal and criteria lines are adjusted based on the average concentration of the observed species. As the average concentration becomes smaller, the criteria and goal lines become larger to adjust for the model's ability to predict at low concentrations.

Figure 3.2.8 Example bugle plot of sulfate mean fractional bias as a function of modeled concentration.



Source: Morris et al, 2005

3.2.3 Ozone Model Performance

It is recommended that, at a minimum, statistical performance metrics be calculated for hourly ozone and 8-hour ozone maxima for each day of the model simulation used to support the attainment demonstration. The EPA recommends that the metrics be calculated both for all pairs of modeled and observed data and for pairs in which the hourly or 8-hour daily max values are above 60 ppb. Another acceptable approach would be to estimate metrics binned by observed ozone concentration. This would allow for a thorough evaluation of the model tendencies to estimate ambient concentrations in different observed ranges of interest. Wherever possible, these types of performance measures should also be calculated for ozone precursors and related gas phase oxidants.

Ozone precursors and related gas-phase oxidants (partial list) are listed below.

- Total Volatile Organic Compounds (VOCs)
- Speciated VOC

- Nitric acid (HNO_3)
- Nitric oxide (NO)
- Nitrogen dioxide (NO_2)
- Peroxyacetyl nitrate (PAN)
- NO_y ($\text{NO}_x = \text{NO} + \text{NO}_2$ and other oxidized nitrogen compounds)
- Carbon monoxide (CO)

3.2.4 $\text{PM}_{2.5}$ Model Performance

Performance metrics for PM and regional haze are similar to those calculated for ozone. Metrics should be estimated for components of $\text{PM}_{2.5}$ and PM precursors. Since modeling for $\text{PM}_{2.5}$ and regional haze will likely require modeling different times of year, season-specific statistics and graphical displays are helpful for evaluating and diagnosing model performance. Statistics and graphics can be averaged for various time scales depending on the model application. For example, statistical metrics and scatterplots can show daily averaged ambient-modeled pairs or annual average pairs for attainment demonstration of the daily and annual $\text{PM}_{2.5}$ standards respectively. In addition, the EPA recommends that daily pairs be grouped by season or month and statistics be given for different times of the year since different processes dominated $\text{PM}_{2.5}$ formation and fate in different seasons. Note that in this case, pairings should be performed on 24-hour average concentrations and statistics may then be reported for subgroups (seasons, regions etc.) of this data. This is different than pairing monthly or seasonally averaged data since statistics and plots tend to look “better” as the averaging time increases from daily to monthly to quarterly to annual. As such, daily pairs should always be examined to ensure a detailed look at model performance on the time scale of the measurements (24-hour average). Finally, air agencies may also want to subset the 20% clearest and most impaired visibility days at IMPROVE sites or the “high” modeled $\text{PM}_{2.5}$ days (e.g. the 10% highest modeled days in each quarter) to examine model performance on the days which will potentially be used to evaluate air quality goals.

Because $\text{PM}_{2.5}$ is a mixture, a meaningful performance evaluation should include an assessment of how well the model is able to predict individual chemical components that constitute $\text{PM}_{2.5}$. Components of $\text{PM}_{2.5}$ of interest include:

- Sulfate ion (SO_4)
- Nitrate ion (NO_3)
- Ammonium ion (NH_4)
- Elemental Carbon (EC)

- Organic Carbon (OC) and/or Organic Carbon Mass³⁰
- Crustal (weighted average of the most abundant trace elements in ambient air)
- Sea salt constituents (Na and Cl)³¹
- Other mass including Non-Carbon Organic Matter (NCOM) and metal oxides not captured by the crustal component

There are a number of gas-phase species that can be used to evaluate PM_{2.5}. Their presence may affect the formation of secondary PM and the response of secondary PM components to emissions strategies. Also, the model's performance in predicting certain gaseous species may provide diagnostic clues which help explain poor performance. Gas phase species of most interest for performance evaluation due to being a direct precursor to secondarily formed PM_{2.5} are listed below:

- Nitric acid (HNO₃)
- Ammonia (NH₃)
- Sulfur dioxide (SO₂)
- Volatile Organic Compounds (VOCs)

Other related gas-phase oxidants (partial list) that indirectly influence PM_{2.5} formation and destruction are listed below.

- Ozone (O₃)
- Nitric oxide (NO)
- Nitrogen dioxide (NO₂)
- Peroxyacetyl nitrate (PAN)
- NO_y (sum of NO_x and other oxidized compounds)
- Carbon monoxide (CO)
- Hydrogen peroxide (H₂O₂)

Some of the species listed above are currently available from either existing monitoring network systems and/or special studies. However, it is important to note that many of the species listed above are not routinely measured (e.g., H₂O₂, HNO₃, and NH₃) or measurements are not co-located with speciated PM measurements. Model performance can best be assessed using extensive databases, such as those obtained in major field studies. Where possible, model

³⁰ For predicted/observed comparisons, organic carbon is preferred over organic carbon mass to allow for transparency between model predictions and observed measurements. Ambient measurements will generally only account for the carbon portion of organic carbon. Organic carbon mass may include hydrogen, oxygen, and other components.

³¹ White (2008) recommends the use of 1.8xCl⁻ to characterize ambient sea salt concentrations at coastal IMPROVE sites due to uncertainty in the XRF Na measurements.

time periods can be prioritized to correspond to periods when field study or special study data was collected. However, it is recognized that many of the precursor species will not be available for every model application.

3.3 Ambient Measurement Networks

Provided below is an overview of some of the various ambient air monitoring networks currently available. Network methods and procedures are subject to change annually due to systematic review and/or updates to the existing monitoring network/program. Please note, there are other available monitoring networks which are not mentioned here and more details on these networks and measurements can be obtained from other sources, if necessary.

3.3.1 AQS

The Air Quality System (AQS) is a repository of ambient air pollution data and related meteorological data collected by EPA, state, local and tribal air pollution control agencies from tens of thousands of monitors (it is not an actual monitoring network). The monitoring data in AQS are the result of the various CAA requirements to provide a national database of ambient air pollution data. This information management system contains data on over 1,000 pollutants from 1957 through the present day. AQS contains all the routine hourly gaseous pollutant data collected from State and Local Air Monitoring Stations (SLAMS) sites. SLAMS is a dynamic network of monitors for state and local directed monitoring objectives (e.g., control strategy development) which consists of thousands of monitoring stations. The SLAMS network includes stations classified as NCore, PAMS, and Speciation, and stations formerly categorized as NAMS, but does not include Special Purpose Monitors (SPM) and other monitors used for non-regulatory or industrial monitoring purposes. AQS also contains data from the IMPROVE monitoring network, described separately in section 3.3.3 of this document.

The AQS database includes criteria pollutant data (SO₂, NO₂, O₃, CO, PM₁₀, PM_{2.5}, and Pb) and speciation data of particulate matter (SO₄, NO₃, NH₄, EC, OC, and crustal material), air toxic data, photochemical assessment data, and meteorological data. The data are measured and reported on an hourly or daily average basis. The AQS system continues to expand to include more ambient air pollutants. An overview of the AQS can be found [here](#). For querying the database or viewing the data one can use the EPA's [AirData website](#), which is a collection of user-friendly visualization tools for air quality analysts. The tools generate maps, graphs, and data tables dynamically. An [AQS User's Guide](#) is also available.

3.3.2 NCore

The term “NCore monitoring network” (for national core) refers to a set of monitoring sites in major urban areas that generally started operating in 2011. These sites combine several advanced measurement systems for particles, pollutant gases and meteorology. Specifically, chemical measurements at these sites includes PM_{2.5} speciation, continuous mass, 24-hr filter-based mass, ozone, CO, SO₂, NO, NO_y. More information about this network is available [here](#).

3.3.3 IMPROVE

The Interagency Monitoring of PROtected Visual Environments (IMPROVE) network began in 1985 as a cooperative visibility monitoring effort between EPA, federal land management agencies, and state air agencies (IMPROVE, 2011). Data are collected at Class I areas across the U.S., mostly at national parks, national wilderness areas, and national wildlife refuges. As of 2018, there were approximately 160 IMPROVE sites that have complete annual PM_{2.5} mass and/or PM_{2.5} species data. There are 110 IMPROVE monitoring sites which represent air quality at the 156 designated Class I areas. The additional IMPROVE sites are “IMPROVE protocol” sites, which are generally located in rural areas throughout the U.S., although there are also a handful of urban sites in the U.S. These protocol sites provide additional spatial information across the country, being generally located in areas where there are few Class I areas. The protocol sites use the IMPROVE monitoring samplers and collection routines. In addition to IMPROVE data that is available in AQS, the IMPROVE program provides summary datasets that contains information and pre-calculated data needed for Regional Haze Rule analyses. This includes daily average and annual data for the 20% most impaired and 20% clearest visibility days. The IMPROVE documentation and data can be found [here](#). IMPROVE data advisories are posted [here](#).

3.3.4 CASTNet

Established in 1987, the Clean Air Status and Trends Network (CASTNet) is a dry deposition monitoring network where PM data are collected and reported as weekly average data (U.S. EPA, 2012a). In addition, this network measures and reports hourly ozone concentrations. CASTNet provides atmospheric data on the dry deposition component of total acid deposition, ground-level ozone and other forms of atmospheric pollution. The data (except for ozone) are collected in filter packs that sample the ambient air continuously during the week. As of 2018, CASTNet is comprised of 95 monitoring stations across the U.S. The longest data records are primarily at eastern U.S. sites. More information can be obtained through the [CASTNet website](#).

3.3.5 CSN

The Chemical Speciation Network (formerly known as STN: The Speciation Trends Network) began operation in 1999 to provide nationally consistent speciated PM_{2.5} data for the assessment of trends at representative sites in urban areas in the U.S. The CSN was established by regulation and is a companion network to the mass-based Federal Reference Method (FRM) network implemented in support of the PM_{2.5} NAAQS. As part of a routine monitoring program, the CSN quantifies mass concentrations and PM_{2.5} constituents, including numerous trace elements, ions (sulfate, nitrate, sodium, potassium, and ammonium), elemental carbon, and organic carbon. As of 2018, there were 52 trends sites in the CSN nationally. CSN trends sites are largely static urban monitoring stations with protocols for sampling methods that are dedicated to characterizing aerosol mass components in urban areas of the U.S. to discern long-term trends and provide an accountability mechanism to assess the effectiveness of control programs. In addition, in 2018, there were approximately 100 supplemental speciation sites that are also part of the CSN. The CSN data at trends sites are collected 1 in every 3 days, whereas supplemental sites collect data either 1 in every 3 days or 1 in every 6 days. Comprehensive information on the CSN and related speciation monitoring can be found [here](#).

3.3.6 NADP

Initiated in the late 1970s, the National Acid Deposition Program (NADP) monitoring network began as a cooperative program between federal and state agencies, universities, electric utilities, and other industries to determine geographical patterns and trends in precipitation chemistry in the U.S. NADP collects and reports wet deposition measurements as weekly average data (NADP, 2013). The network is now known as NADP/NTN (National Trends Network), with nearly 200 sites in operation. The NADP analyzes the constituents important in precipitation chemistry, including those affecting rainfall acidity and those that may have ecological effects. The NTN measures sulfate, nitrate, hydrogen ion (measure of acidity), ammonia, chloride, and base cations (calcium, magnesium, potassium). Detailed information regarding the NADP/NTN monitoring network can be found [here](#).

The Ammonia Monitoring Network (AMoN) is a NADP network that provides additional ambient and deposition ammonia data. The network began as part of a special study in 2007, was approved as an NADP network in 2010, and as of 2016 included approximately 50 monitoring sites across the U.S. AMoN monitors collect 2-week average data. More information can be found [here](#).

3.3.7 SEARCH

The South Eastern Aerosol Research and Characterization (SEARCH) monitoring network was established in 1998 and is a coordinated effort between the public and private sector to characterize the chemical and physical composition as well as the geographical distribution and long-term trends of PM_{2.5} in the Southeastern U.S. (Edgerton, 2005; Hansen, 2003) The SEARCH network officially shut down in December 2016. However, SEARCH data are still useful for evaluating model performance for any simulations that included the Southeastern U.S. between 1998 and 2016. SEARCH data were collected and reported on an hourly/daily basis. A total of eight sites were operated at one time by SEARCH, although only six operated during SEARCH's final years: Birmingham, Alabama (urban), Centreville, Alabama (rural), Gulfport, Mississippi (urban), Jefferson Street, Atlanta, Georgia (urban), Oak Grove, Mississippi (rural) (not operational as of 2010), Yorkville, Georgia (rural) (not operational as of 2009), suburban Pensacola, Florida (suburban), and downtown Pensacola, Florida (urban). Historical SEARCH data from 1992-2016 can be accessed [here](#).

3.3.8 Speciated PM_{2.5} Data Summary

Speciated PM_{2.5} data play an especially important role in performance evaluation, as the deterministic models predict exact chemical components which can be compared to some of the corresponding measured analytes. There are known positive and negative sampling artifacts as well as analysis artifacts associated with FRM and speciation monitors (Frank, 2006). Due to the complex nature of the measurements, a basic understanding of the various PM_{2.5} and speciation monitoring technology and measurements are needed before undertaking a model evaluation.

Table 3.2: Known measurement artifacts for PM_{2.5} and speciated PM for different monitoring networks.

Network	Measurement	Notes	Sampling Time
FRM	PM _{2.5}	- Negative artifacts: ammonium nitrate, organic carbon - Positive artifacts: organic carbon, water	24-hour average 1/3 days or 1/6 days (some daily sites)
	PM _{2.5}	- Negative artifacts: ammonium nitrate, organic carbon	

Network	Measurement	Notes	Sampling Time
CSN (formally STN)		- Positive artifacts: organic carbon, water -Note that positive and negative artifacts for PM_{2.5} may be different from artifacts for individual PM components because the speciated PM_{2.5} samples are collected on different types of filters than are used for total PM_{2.5} gravimetric measurements -CSN PM_{2.5} mass may be different from FRM measurements due to differences in handling procedures	24-hour average 1/3 days or 1/6 days
	SO ₄		
	NO ₃		
	NH ₄		
	OC	- Blank correction is needed to account for positive artifact³² - Before 2007, OC/EC split was operationally defined using Thermal Optical Transmittance (TOT) method (NIOSH). CSN monitors switched to using the Thermal Optical Reflectance (TOR) method (consistent with	

³² CSN OC measurements reported in AQS currently have artifact correction applied, although ambient data provided in SMAT-CE does already include a blank correction. The same artifact correction techniques are applied to measurements from CSN and IMPROVE networks. The CSN began implementing IMPROVE-like samplers and the IMPROVE analysis method in 2007. The implementation was fully completed in late 2009. Work by Malm et al (2011) suggests that CSN OC from 2005 and 2006 (before the switch in samplers) likely had a positive multiplicative bias of ~1.2 and a positive additive bias between 1.0 and 1.9 µg/m³ depending on the time of year. We recommend using artifact corrected measurements where available and adjusting any uncorrected AQS CSN OC data by subtracting 1.4 µg/m³ for measurement before the switch to IMPROVE-like measurements and by subtracting 0.12 µg/m³ from measurements after the switch based on Frank (2012).

Network	Measurement	Notes	Sampling Time
CSN (formerly STN) (con't.)		IMPROVE monitors) between 2007 and 2009. ³³	
	EC	- Before 2007, OC/EC split was operationally defined using TOT method (NIOSH). CSN monitors switched to using the TOR method (consistent with IMPROVE monitors) between 2007 and 2009 (see footnote 23)	
CASTNet	SO ₄		weekly average
	NO ₃	Split between NO ₃ and HNO ₃ may not be reliable in warm weather due to conversion from NO ₃ to HNO ₃ . Recommend comparing total nitrate (NO ₃ + HNO ₃) between model and observations.	
	NH ₄		
	SO ₂		
	HNO ₃	Split between NO ₃ and HNO ₃ may not be reliable in warm weather due to conversion from NO ₃ to HNO ₃ . Recommend comparing total nitrate (NO ₃ + HNO ₃) between model and observations.	
	PM _{2.5}	- Negative artifacts: ammonium nitrate, organic carbon - Positive artifacts: organic carbon, water	

³³ The transition from TOT to TOR for CSN monitors occurred in shifts: 56 sites switched in May 2007, 63 sites switched in April 2009, and 78 sites switched in October 2009.

Network	Measurement	Notes	Sampling Time
IMPROVE		-Note that positive and negative artifacts for PM _{2.5} may be different from artifacts for individual PM components because the speciated PM _{2.5} samples are collected on different types of filters than are used for total PM _{2.5} gravimetric measurements	24-hour average 1/3 days
	SO ₄ and S	-IMPROVE monitors measure both elemental S (by XRF) and ionic SO ₄ ⁻ by ion chromatography. Generally, either measurement is reliable and may be used for model evaluation purposes although some caveats should be noted. ³⁴	
	NO ₃		
	NH ₄	-Only available at a limited number of sites for a limited number of years	
	Organic Carbon	- OC/EC split is operationally defined using Thermal Optical Reflectance (TOR) analysis. - Blank corrections based on a median measured positive OC artifact from back-up filters at six sites are applied on a month-specific basis to all data before they are reported (Chow et al, 2010; Watson et al., 2009). Frank (2012) recommended changing blank	
IMPROVE (con't.)			

³⁴ Hyslop et al (2012) report that XRF elemental sulfur measurements are somewhat affected by changes in XRF methodologies over time. Also, prior to 2000, filters used to collect sulfate for ion chromatography became clogged during high sulfate episodes. Changes in filter collection techniques eliminated this problem after 2000. In addition, recent literature by Tolocka and Turpin (2012) suggests that differences between XRF sulfur and ion chromatography sulfate are due to the presence of organic sulfur in aerosol (which would be measured by XRF but not IC). If this is the case, then the IC sulfate measurement is more appropriate for comparison with modeled sulfate which generally does not include formation of organic sulfur compounds.

Network	Measurement	Notes	Sampling Time
		correction procedures for both IMPROVE and STN OC measurements. These recommendations have not yet been implemented.	
	Elemental Carbon	- OC/EC split is operationally defined using Thermal Optical Reflectance (TOR) analysis.	
	Sodium	XRF analysis is not as sensitive to sodium as other methods and generally under-reports sodium concentrations.	
	Silicon	XRF silicon measurements are unreliable at high sulfur conditions (when S/Si > about 7)	
	Aluminum	Elemental concentrations above the MDL can go undetected. IMPROVE has published an alternate soil calculation which estimates Al based on Si concentrations. ³⁵	

In general, the speciated PM_{2.5} data can be directly compared to the model outputs. Of note, care should be taken in examining issues with blank corrections for organic carbon (especially when measured OC is low) as well as the EC/OC split. Prior to 2006, the CSN and IMPROVE networks used different analysis techniques when estimating EC and OC (CSN monitor locations switched to a similar method to IMPROVE between 2007 and 2009, depending on the monitor). The EC/OC analysis method will generally have a larger impact on EC concentrations than OC concentrations. The difference in OC/EC splits between the two techniques has been investigated in depth in the literature and by IMPROVE staff (Chow, 2001, Chow, 2010, White, 2007). It may not be appropriate to compare EC concentrations between networks for years prior to 2009 (although the data can still be used to evaluate model performance).

Total PM_{2.5} mass measured gravimetrically at CSN and IMPROVE monitors is known to have several measurement artifacts (both positive and negative) (Frank, 2006, Simon et al., 2011,

³⁵ Due to difficulties in detecting Al, IMPROVE sometimes uses an alternative SOIL calculation which does not include Al: $SOIL = 3.48 * Si + 1.63 * Ca + 2.42 * Fe + 1.94 * Ti$
http://vista.cira.colostate.edu/improve/publications/SOPs/ucdavis_sops/sop351_V2.pdf.

Malm et al., 2011). Consequently, summing the mass of all PM_{2.5} species components is not likely to give the same answer as the total measured PM_{2.5} mass from a Teflon filter. Therefore, model evaluations should concentrate on comparisons with speciated PM_{2.5} components at these sites, rather than total PM_{2.5} mass.

FRM monitors do not measure all of the PM_{2.5} in the air, and the speciation samplers don't measure PM_{2.5} in the same way as the FRM monitors (Frank, 2006). Due to these positive and negative artifacts, the FRM data may not be directly comparable with model outputs without adjustment. The models predict PM species as they might be measured in the ambient air, but the FRM measurements may not always measure what is in the air (due to known positive and negative artifacts). As part of the PM_{2.5} attainment test, we recommend default methodologies to adjust speciation (CSN and IMPROVE) data to better approximate the FRM data (see sections 4.4 and 4.5). A similar adjustment could be made to the model output data to allow the direct comparison to FRM measurements. However, as noted earlier, there may be limited value of information gained by evaluating daily average total measured PM_{2.5} mass (as compared to PM_{2.5} components). More meaningful information may be gleaned from continuous PM_{2.5} ambient data.

Another issue to consider when comparing modeled and observed PM concentrations is the size definitions for PM. IMPROVE and CSN ambient monitors measure PM_{2.5} using inlets which screen out any particles with aerodynamic diameters greater than 2.5 μm . Air quality models use varying schemes to characterize particulate matter size distributions. The two most common modeling schemes are the sectional treatment and the modal treatment. The default configuration for CAMx includes a sectional aerosol treatment while the default configuration for CMAQ includes a modal aerosol treatment, although other versions of these models exist with alternate aerosol treatments. Sectional aerosol modules split particles into bins defined using discrete size cut-points based on aerodynamic diameter (e.g., particles with aerodynamic diameters between 1 μm and 2.5 μm). One common sectional set-up includes 2 bins, one containing particles with aerodynamic diameters < 2.5 μm (fine PM) and one containing particles with aerodynamic diameters > 2.5 μm (coarse particles). Other models have split the fine PM into more than two bins (Nolte et al., 2008; Pandis et al., 1993). With sectional models, the comparison to measured PM_{2.5} is straightforward so long as one of the PM bins has a cutoff at an aerodynamic diameter of 2.5 μm (i.e., add up PM mass in all bins less than 2.5 μm). The modal approach treats PM as occurring in distinct “modes,” each one having a lognormal distribution. Each PM mode is characterized by the geometric mean diameter and the geometric standard deviation of the diameter (the geometric mean and standard deviation can be tracked for particle number, surface area, mass or all three). With modal aerosol treatment, PM_{2.5} can be estimated in several ways. One method is to simply sum the mass in the modes that generally contain fine PM. Another method would be to use the geometric mean and

standard deviation to calculate the fraction of PM mass in each mode which is associated with particles less than 2.5 μm . However, there are several complicating factors with taking the second approach. First, the EPA's NEI and many other inventories define PM_{2.5} as being entirely less than 2.5 μm in diameter. If these primary emissions are injected into a modal model (generally into a fine PM mode), they are instantaneously mixed with existing aerosol mass in that mode. The tail of the fine PM mode will include particles greater than 2.5 μm . Therefore, a fraction of the PM that was operationally defined as primarily emitted PM_{2.5} (diameter < 2.5 μm) would be incorrectly distributed into the > 2.5 μm size range based on the mode distribution. If primary emissions were quantified based on modes versus a discrete cut-point, then this would not be a problem. Secondly, some modal models have been shown to over-predict the peak-concentration diameter and distribution width of the fine PM mode (Kelly et al., 2011; Kelly et al., 2010). This would lead to under-predictions of the PM_{2.5} fraction by increasing the mass fraction in the > 2.5 micron diameter range. Air agencies should consider these complications when deciding whether to calculate the fraction of PM mass in each mode below the 2.5 μm cut-point or to simply sum mass over the fine PM mode(s).

Finally, although we recommend weighing performance of speciated PM components more heavily than total PM, some additional insight can be gained by looking at Federal Equivalent Method (FEM) continuous PM_{2.5} measurements³⁶. Since speciated measurements are generally derived from filters, these measurements are usually taken as 24-hour averages. The FEM continuous measurements provide a diurnal profile of PM_{2.5} concentrations that can be compared against hourly model outputs to determine whether the model is replicating the measured temporal pattern.

3.4 Diagnostic Evaluation

The goal of a diagnostic model evaluation is to determine whether the model correctly represents the physical and chemical processes that control the ambient concentrations of precursors and secondary pollutants. It is possible that a model can incorrectly represent the relative amount of primary emissions versus secondary production or that a model can incorrectly represent the importance of dispersion, deposition or chemical reaction as a sink. Thus, the ability of a model to accurately reproduce the observed concentration of a particular pollutant does not guarantee that the model correctly simulated the processes that determine the concentration of the pollutant. The goal of a diagnostic evaluation is to investigate the processes that determine the ambient concentrations of ozone, PM_{2.5} and their precursors, and to develop confidence that the model can accurately predict how these concentrations will

³⁶ Monitoring of atmospheric air quality for purposes of determining compliance with the NAAQS generally requires the use of either Federal reference methods (FRM) or equivalent methods (FEM), as specified in Section 2.1 of Appendix C to 40 CFR part 58.

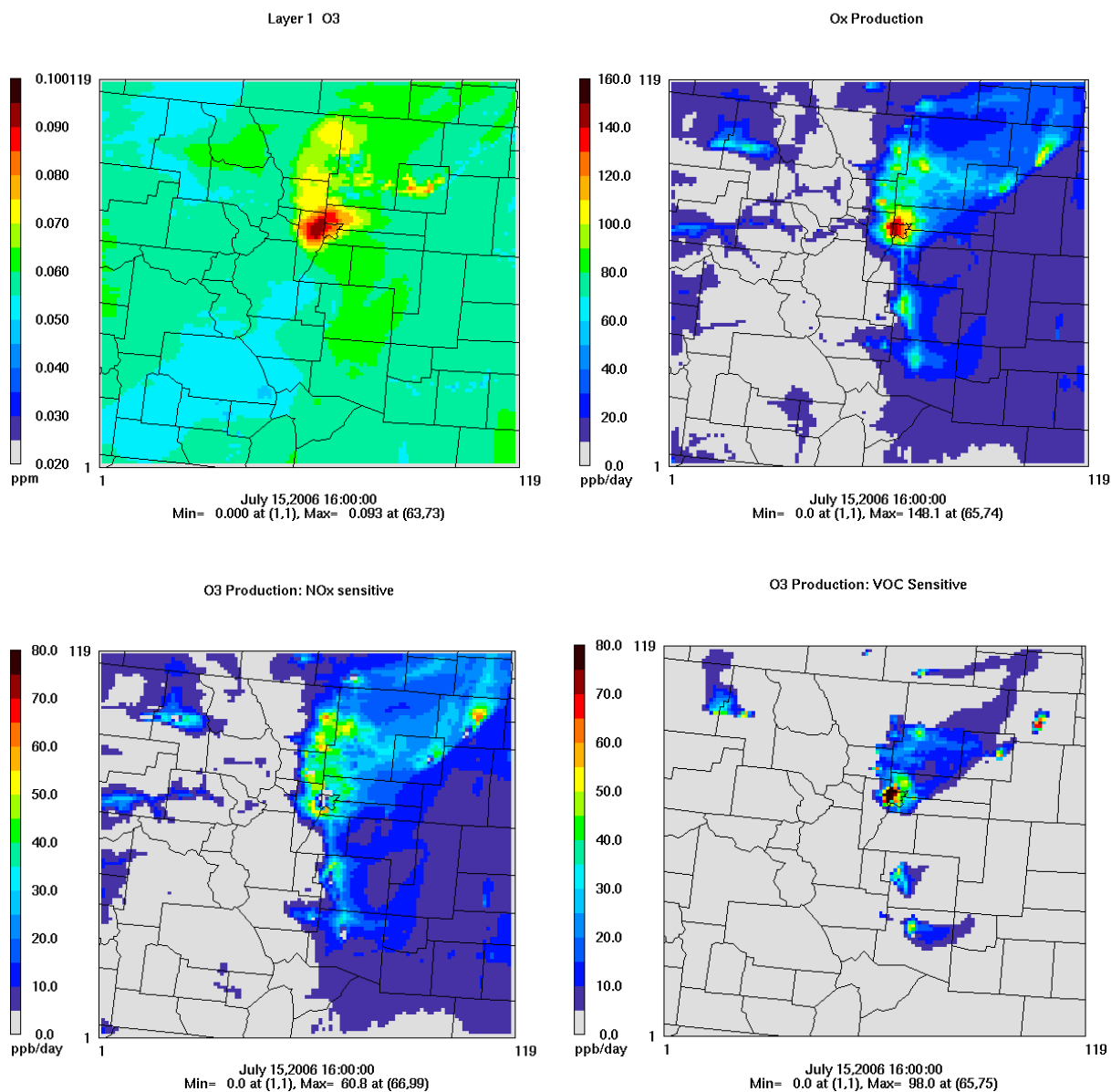
change in the future (e.g., Arnold et al., 2006). It is likely that research grade measurements needed to perform a diagnostic evaluation will not be available in many SIP modeling studies, however, it can still be valuable to perform diagnostic analyses and compare the results with previous modeling research studies.

Several different tools and analysis methods are available for use in diagnostic model evaluation including process analysis, indicator ratios, source apportionment methods, model sensitivity studies, and retrospective studies.

3.4.1 Process Analysis

Both the CMAQ and CAMx models include a process analysis tool (Jeffries and Tonnesen, 1994) that provides additional diagnostic information on the chemical reactions and physical processes (e.g., emissions, deposition, advection, vertical mixing, and net change from chemistry) that determine species concentrations. Chemical reaction data can be output either as the hourly integrated reaction rate (IRR) for each reaction or as a summary of key reactions in the chemical process analysis (CPA). Physical processes can be output as hourly concentration changes in the integrated process rate (IPR) file. Detailed analysis of IRR and IPR outputs have been demonstrated in research studies (Jang et al., 1995; Vizuite et al., 2008; Henderson et al., 2011), but significant time and effort are required to complete these analyses. The CPA output provides a more limited set of chemical process information that is more accessible and that can be visualized using the same tools used to analyze model concentration output files. Minimal computational cost is required to produce the CPA files, and they are in the same format as the model concentration files and can be viewed using the same visualization tools. Below are examples of these plots comparing modeled ozone concentration, daily total Ox ($Ox = O_3 + O_3P + O_1D + NO_2 + 2*NO_3 + PNA + PAN + 3*N_2O_5$) production, and net ozone production in NO_x limited and oxidant limited chemical regimes. The CPA tool can also provide information on the chemical reactions of VOC, NO_y and radical species. The need for a process analysis evaluation and the specific processes investigated should be determined on a case-by-case basis.

Figure 3.4.1 Chemical process analysis plots showing modeled ozone concentration, daily total Ox production, and net ozone production under VOC sensitive and NOx sensitive conditions.



3.4.2 Indicator Ratios

One way to evaluate the response of the model is to examine predicted and observed ratios of indicator species. Indicator species techniques have been developed for both ozone and secondary PM species (in particular nitrate) (Sillman, 1995, 1998; Ansari and Pandis, 1998;

Blanchard et al., 2000; Tonnesen and Dennis, 2000a and 2000b). If ratios of observed indicator species are very high or very low, they provide a sense of whether further ozone or secondary PM_{2.5} production at the monitored location is likely to be limited by availability of NO_x or VOC (or NH₃ in the case of particulate nitrate). Agreement between paired observed and predicted ratios suggests a model may correctly predict the sensitivity of ozone or secondary PM_{2.5} at the monitored locations to emission control strategies. Thus, the use of indicator species aims to validate the modeled chemical regime and may help to build confidence in the RRFs predicted from the specific model application.

For ozone, measurements of certain “indicator species ratios” (e.g., comparisons between modeled and observed ratios: O₃/NO_y, O₃/HNO₃) are a potentially useful way to assess whether local ozone formation is VOC or NO_x limited at any particular point in space and time, as well as help reveal whether the model is correctly predicting the sensitivity of ozone to VOC and/or NO_x controls (Millford et al., 1994; Sillman, 1995, 1997, 1998, 2002; Lu and Chang, 1998). Tonnesen and Dennis (2000a and 2000b) distinguished between short lived indicators of instantaneous rates of production of ozone (PO₃) or odd oxygen (PO_x) versus long lived indicators of peak ozone concentration and found that the ratio of production of H₂O₂ to production of HNO₃ (PH₂O₂/PHNO₃) is strongly associated with PO_x sensitivity to VOC and NO_x. Tonnesen and Dennis also found that the ratio of formaldehyde to NO₂ was useful as an indicator of ozone sensitivity, and this ratio can be evaluated using satellite data (Martin et al., 2004; Duncan et al., 2010). For PM, such a comparison may reveal whether the model is predicting sensitivity of secondary components of PM_{2.5} to changes in SO₂, NH₃, VOC and/or NO_x controls correctly (Ansari and Pandis, 1998; Blanchard et al., 2000; Pun and Seigneur, 1999, 2001). If a model accurately predicts observed indicator species relationships, then one can conclude with additional confidence that the predicted change in future year ozone or PM may be accurate.

Although ratios of indicator species have the potential to be quite useful, they should be used with caution since different studies have identified different ranges of values to characterize VOC and NO_x limited regimes in different locations. Table 3.3 summarizes the range of values determined for 10 indicator species or ratios in various studies. In cases where the NO_x and VOC limited ranges are broad or overlap, air agencies should attempt to use values from studies in the local area. Air agencies should be cautious with respect to the use of indicator species when the range of observed values does not provide a clear direction of control. When this occurs, agreement between predictions and observations does not necessarily imply that the response to controls as predicted by the model is correct (especially for secondary particulate matter to changes in precursors). If a model predicts observed values of indicator species relationships such that observed and predicted value fall within the same range, this provides

some confidence that the predicted change in ozone or secondary particulate matter may be accurate.

A second precaution is that this method often requires more types of measurements than are commonly available. In some cases, it may be difficult to calculate meaningful indicator ratios from relatively imprecise measurements from routine monitoring networks.

Table 3.3: Ranges of indicator species/ratios that have been reported for VOC and NO_x limited regimes.

indicator	median VOC-sensitive	transition	median NO _x -sensitive
O ₃ /NO _y	1.6 - 8.8 ^{a,b,d,f,m}	6 - 15 ^{c,d,m,n,q}	8.8 - 26 ^{a,b,d,f,m}
O ₃ /NO _z	5.8 - 16 ^{a,d,f,j,m}	7 - 100 ^{c,f,n,q}	10.1 - 35 ^{a,d,f,j,m}
O ₃ /NO _x	< 15	15 - 60 ^{n,o,q,t}	> 40
O ₃ /HNO ₃	7 - 33.9 ^{a,d,j,k,m}	12 - 25 ^{c,d}	17.2 - 62.9 ^{a,d,j,k,m}
H ₂ O ₂ /HNO ₃	0.3 - 1.5 ^{d,j,m}	0.2 - 2.4 ^{c,e,h,n-q}	0.4 - 3.6 ^{d,j,m}
H ₂ O ₂ /NO _z	0.2 - 1.1 ^{a,j}	0.2 - 0.25 ^c	0.6 - 1.3 ^{a,j}
H ₂ O ₂ /NO _y	0.2 - 0.4 ^{a,j}	0.12 - 0.17 ^c	0.6 - 1.0 ^{a,j}
HCHO/NO ₂	< 1	1-2 ^{n,o,u}	> 2
NO _z /NO _y	< .5	0.5-0.6 ^f	> 0.6
NO _y	7.7 - 12.2 ^j	5 - 20 ^{c,e,f,n,r,s}	3.2 - 5.7 ^j

^aCastell et al., 2009; ^bXie et al., 2011; ^cTorres-Jardon and Keener, 2006; ^dSillman and He, 2002; ^eSillman, 1995; ^fLu and Chang, 1998; ^gStein et al, 2005; ^hSillman et al., 1997; ⁱMartilli et al., 2002; ^jJimenez and Baldasano, 2004; ^kTorres-Jardon et al, 2009; ^lChock et al, 1999; ^mSillman et al., 2003; ⁿZhang et al, 2009; ^oTonnesen and Dennis, 2000a; ^pHammer et al., 2002; ^qLiang et al., 2006; ^rMilford et al, 1994; ^sVogel et al, 1995; ^tTonnesen and Dennis, 2000b; ^uMartin et al., 2004

Much of the work done to date with indicator species has focused on peak concentrations of ozone. Limited research has been conducted on development of indicator ratios for secondary PM. This includes work by Blanchard et al., (2000) who examined how indicator species might be used to assess whether particulate nitrate concentrations are limited by NO_x or by ammonia

emissions using mechanisms which incorporate reactions dealing with secondary PM. These authors identify several indicators which appear potentially useful for determining limiting precursors for secondary nitrate PM. The indicators include:

(1) excess NH_3 defined in Equation 3-1 (values greater than zero indicate NO_x limited regimes and values less than 0 indicate ammonia limited regimes);

$$\begin{aligned} \text{excess } \text{NH}_3 = & [\text{NH}_3(\text{g})] + [\text{NH}_4 + (\text{a})] - 2 * [\text{SO}_4 - (\text{a})] - [\text{NO}_3 - (\text{a})] - [\text{HNO}_3(\text{g})] \\ & - [\text{HCl}(\text{g})] + 2 * [\text{Ca}^{2+}] + 2 * [\text{Mg}^{2+}] + [\text{Na}^{+}] + [\text{K}^{+}] + [\text{Cl}^{-}] \end{aligned} \quad [3-1]^{37}$$

(2) The ratio of particulate to total nitrate. Values above 0.9 at high temperatures indicate NO_x limited regimes (values below 0.3 to 0.5 were indicative of ammonia limited regimes).

Ansari and Pandis (1998) also have suggested the use of the gas ratio (GS), defined in equation 3-2, as an indicator of PM formation regimes.

$$GS = \frac{\text{NH}_3^F}{\text{HNO}_3^T} \quad [3-2]^{38}$$

In summary, major challenges in evaluating indicator species include variability in the characteristic ratios for VOC and NO_x limited regimes in different locations and the availability of ambient data. Despite these caveats, comparing predicted and observed relationships of indicator species provides a means of assessing a model's ability to accurately characterize the sensitivity of predicted ozone and predicted secondary components of $\text{PM}_{2.5}$ to changes in precursors.

3.4.3 Source Apportionment

Source apportionment methods and model sensitivity studies are two complementary approaches that can be used to identify emissions sources that contribute to high pollutant concentrations. While these tools do not directly diagnose the model's ability to replicate the real world, they are useful in their ability to further characterize the sources that are most important to high pollutant concentrations within the model. The CMAQ and CAMx models both include options to use source apportionment tools to identify sources that contribute to

³⁷Concentrations are in $\mu\text{mol}/\text{m}^3$, (g) represent gas-phase and (a) represents aerosol phase.

³⁸ NH_3^F is free ammonia (total ammonia – 2*sulfate). HNO_3^T is total nitrate (gas + PM).

the production of ozone (Ramboll, 2018; Kwok et al, 2014) and some components of $PM_{2.5}$, including sulfate, nitrate, ammonium and primary emissions of $PM_{2.5}$ (Ramboll, 2018; Kwok et al., 2013). Source apportionment tools employ a set of model tracers to attribute pollutant concentrations to user selected emissions source sectors and geographic areas. This approach can be useful both as a diagnostic tool to identify sources that contribute to ozone and $PM_{2.5}$ and also as an aid in regulatory analysis to identify emissions control measures that will be effective for attaining air quality standards. An advantage of source apportionment approaches is that tracers attribute the mass contribution from a source to a receptor and, therefore, this approach is less susceptible to the effects of non-linear chemistry, which can complicate the interpretation of model sensitivity simulations.

3.4.4 Sensitivity Studies

Model sensitivity simulations can be used to identify model inputs (IC/LBC, meteorological data, chemical reactions, and emissions) that have the greatest impact on model-predicted concentrations. The objective of sensitivity tests is to identify whether the inputs have a large enough influence that errors in these inputs could be a driving influence on the model predictions. In “brute-force” sensitivity simulations, the model input data is modified directly (e.g., increasing or decreasing emissions in the model input file). Brute-force simulations are relatively easy to implement but are resource intensive when many different inputs must be evaluated. The Direct Decoupled Method (DDM) is an approach that can be used to evaluate the first order sensitivity to multiple model inputs in a single model simulation (e.g., Cohan et al., 2005; Napelenok et al., 2006). Because of non-linearity in chemical reactions, first-order sensitivity is not always sufficient, and high-order DDM (HDDM) can be used to evaluate second order sensitivities to inputs that are subject to non-linear chemistry (Zhang et al., 2012b).

In cases where the model performs poorly in the base case, sensitivity simulation may be useful to identify potential causes for poor model performance. However, caution should be used in modifying inputs to achieve good model performance because arbitrarily “tuning” of model input data to fit the observations can introduce compensating errors. For example, if a model underestimates observed ozone because the meteorological data is overly dispersive, the model performance could be improved by increasing emissions or LBC concentrations, but this model would not be reliable for predicting future concentrations because its good performance in the base case was achieved through compensating errors in the input. An appropriate use of sensitivity approaches is to identify each of the processes or inputs that has a large effect on model predictions, and then perform additional analysis of those inputs to determine if they are accurately represented in the base case model.

3.4.5 Dynamic Model Evaluation

A second method for assessing a model's performance in predicting the sensitivity of ozone or PM_{2.5} species to changes in emissions is to perform a retrospective dynamic analysis. This involves comparing model predicted historical trends with observed trends. Retrospective analyses provide potentially useful means for diagnosing why a strategy did or did not work as expected. They also provide an important opportunity to evaluate model performance in a way that is closely related to how models are used to support an attainment demonstration.

A dynamic evaluation uses various analyses to assess the accuracy of the model in characterizing the sensitivity of ozone and/or PM_{2.5} to changes in emissions. Although dynamic evaluation is always recommended, the measurements and resources needed for a dynamic evaluation may not be readily available to air agencies performing SIP modeling. Additional challenges for retrospective analyses include identifying appropriate case studies for which responses to emissions changes are large enough to be distinguished in ambient data, developing or obtaining equivalent and appropriate emissions for multiple historical years, and disentangling the confounding influences of year to year changes in meteorology and emissions.

A retrospective analysis is intended to examine the ability of the model to respond to emissions changes by comparing recent trends in observed ozone or PM_{2.5} concentrations to the model-predicted trend over the same time period. The approach is a direct assessment of what is most important in an attainment demonstration: does the model accurately predict changes in air quality as a result of changes in emissions? As part of a retrospective analysis, the model is run for (a) current episodes or time periods and (b) episodes in one or more historical time periods using the emissions and meteorological inputs appropriate for each time period modeled.

While retrospective analyses may be useful, it may be difficult to obtain meteorological and emissions inputs for the historical time period(s) that are calculated using techniques and assumptions that are consistent with the calculation of these same inputs for the current time period. Using inconsistent inputs will confound the interpretation of the predicted trend. One method for ensuring consistent methodology for emissions estimates is to backcast emissions from the most recent year to the earliest year. The model should respond in a predictable way if the emissions changes are large enough. Hence, modeling an emissions change of only a few percent would not be viable. However, if NO_x or SO₂ emissions have been reduced by a large percentage (e.g., 30% or more) over a relatively short time period, then that may be a good time period to test the response of the model.

Because differences in meteorology between years can confound the apparent change in pollutants, a complete retrospective analysis could include multiple sensitivity runs using both

year-specific meteorology and constant meteorology. The year-specific meteorology would allow the modeler to compare modeled and observed trends most accurately, and the constant meteorology would help inform the analysis on what portion of the change in pollutant concentrations were due to emissions versus meteorological differences.

Retrospective analyses are one of the few tools that can be used to determine if the model is responding “adequately” or “correctly” to control measures. Recent efforts to perform this type of analysis have been undertaken by Zhou et al (2013), Gilliland et al. (2008), Godowitch et al. (2010), Pierce et al. (2010) and Foley et al. (2014). These published analyses may be used to better understand the ability of certain models to properly capture relationships between ambient pollution levels and emissions.

Another dynamic evaluation approach is to look at operational performance under varying conditions (e.g., by day of the week, by season, and by region) (Marr and Harley, 2002; Murphy et al, 2007; Harley et al, 2005). The mix of pollutants vary by day of the week and from area to area; when a model shows good operational performance across these different chemical environments, it supports the assertion that it will respond appropriately to changes in emissions. Two studies have performed model evaluations that focused on the model’s ability to capture weekend/weekday changes (CRC, 2011; Pierce et al, 2010).

3.5 Evaluation Tools

There is available software and tools that can be used to process ambient and model data to create statistical output and plots for model performance evaluations. One example is the [Atmospheric Model Evaluation Tool \(AMET\)](#) (Appel, 2011). AMET is built on several open-source software packages and uses the MySQL database software to store paired observation and model output data. There are modules in AMET for evaluating both meteorological and air quality model output. AMET provides a useful set of scripts for creating various types of plots and statistics.

4.0 Assessing Modeled Attainment for Ozone and PM_{2.5}

A *model attainment demonstration* usually consists of two key components: a) analyses which estimate whether a set of simulated emissions reductions corresponding to a control program scenario will result in ambient concentrations that meet the NAAQS and b) an identified set of control measures which will result in the required emissions reductions. This guidance focuses on the first component of a model attainment demonstration; that is, the completion and interpretation of analyses to estimate the amount of emission reduction needed to attain the NAAQS.

Air agencies should determine whether a control program scenario will provide sufficient emission reductions to demonstrate attainment of the NAAQS using the *modeled attainment test*. The modeled attainment test is a technical procedure in which an air quality model is used to simulate base year and future air pollutant concentrations for the purpose of demonstrating attainment of the relevant NAAQS. The recommended test uses model estimates in a “relative” rather than “absolute” sense to estimate future year design values. As explained in more detail in subsequent sections, the fractional changes in air pollutant concentrations between the model future year and model base year are calculated for all valid monitors. These ratios are called *relative response factors* (RRF). Future ozone and/or PM_{2.5} design values are estimated at existing monitoring sites by multiplying the modeled relative response factor for each monitor by the monitor-specific base year design value. The resulting estimates of future concentrations are then compared to the NAAQS. If the future estimates of ozone and/or PM_{2.5} design values do not exceed the NAAQS, then this provides evidence that attainment will be reached.

In addition to the modeled attainment test, air agencies should also consider performing a set of corroboratory analyses to further assess whether a proposed set of emission reductions is likely to lead to attainment of the NAAQS. As discussed later in this section (see section 6), the modeled attainment test and these supplemental analyses should be aggregated into a *weight of evidence determination* to evaluate whether the selected emissions reductions will yield attainment. The concept of relative response factors also applies to modeling for the purpose of setting RPGs for regional haze, the subject of section 5.

4.1 Overview of Modeled Attainment Test

There are four reasons why the recommended modeled attainment test is based on application of the model in a relative sense. First and foremost, this approach has the effect of anchoring the future concentrations to a “real” measured ambient value, which is important given model bias and error in the base year simulation(s). It is reasoned that factors causing bias (either under or over-predictions) in the base case will also affect the future case. While good model

performance remains a prerequisite for use of a model for regulatory analyses, problems posed by imperfect model performance on individual days are expected to be reduced when using the relative approach. An internal EPA analysis (U.S. EPA, 2014a) considered whether daily ratios of model future/current maximum daily 8-hour ozone averages (MDA8) varied strongly as a function of site-specific base case model performance. This analysis was completed using a national model simulation that projected 2020 ozone concentrations from a 2007 base case. The analysis determined that when modeled, MDA8 ozone bias was relatively small (e.g., less than +/- 20 ppb), the average response ratios were not a strong function of the model MDA8 bias. This provides confidence that the model can detect the air quality response in the midst of reasonable levels of absolute bias and error. Second, the relative modeled attainment test allows for a future projection of 3-year average ozone and PM_{2.5} design values or 5-year average visibility values without explicitly having to model a 3-year or 5-year period. Third, because PM_{2.5} concentrations typically consist of a diverse mix of primary and secondary components, the modeled attainment test based on RRFs decreases the possibility of choosing ineffective control strategies based on inaccurate model estimations of PM_{2.5} composition, by assessing component specific RRFs. Fourth, and finally, there is evidence, based on a retrospective modeling analysis of ozone changes between 2002 and 2005 (Foley et al, 2014) and 2002 and 2010 (Hogrefe et al, 2014), that using the model in a relative sense provides better estimates of future ozone design values than using the absolute future year simulation. The correlation between model-projected and actual design values, as well as the accuracy of model projections of attaining a 75 ppb NAAQS, appear to be slightly improved when a relative modeled attainment test is utilized.

Equation (4.1) describes the recommended modeled attainment test in its simplest form, which directly applies for ozone, as applied for monitoring site *i*:

$$(DVF)_i = (RRF)_i * (DVB)_i \quad [4.1]$$

where DVF_i is the estimated design value for the future year in which attainment is required at monitoring site *i*; RRF_i is the relative response factor at monitoring site *i*; and DVB_i is the *base design value* monitored at site *i*. Each of these terms is discussed in more detail below. For PM_{2.5} and visibility, the modeled attainment test is more complicated in that each PM component (defined in a certain way) has its own RRF.

The EPA has developed the [Software for Modeled Attainment Test-Community Edition \(SMAT-CE\)](#) tool to enable completion of the modeled attainment tests for PM_{2.5} and ozone, as well as for calculating changes in visibility in Class I areas. SMAT replaced the previous EPA attainment test software called MATS (Abt, 2014). [SMAT](#) can be found on the EPA's Support Center for Regulatory Atmospheric Modeling (SCRAM) website.

4.1.1 Establishing the Base Design Value

The base design value for each monitoring site (DVB_i) is the anchor point for estimating future year projected concentrations. Because the modeling is being used in a relative sense to determine how the modeled emissions changes will affect air quality design values in an area, it is important to match the base design value as closely as possible to the base year for which future/base ratios will be assessed. That is, if one is estimating the expected air quality change from emissions reductions between 2016 and 2030, it is important to establish an air quality anchor that represents 2016 emissions levels as closely as possible. However, it is well-established that inter-annual variability in meteorological conditions often leads to year to year differences in design values, even with static emissions levels (U.S. EPA, 2012). In addition, there is also year to year variability in emissions due to economic factors (such as recessions) and compliance with regulations. We, therefore, recommend using the base design value approach described below.

For the modeled attainment tests for ozone and $PM_{2.5}$, we recommend using the average of the three design value periods, which include the base emissions inventory year. This average is expected to best represent the air quality resulting from base year emissions with consideration of meteorological and emissions variability. For example, if the modeled attainment test uses base year emissions from 2014, then the base design value (DVB) would be calculated as shown in equation 4.2 for each site i :

$$(DVB)_i = \frac{((DV\ 2014)_i + (DV\ 2015)_i + (DV\ 2016)_i)}{3} \quad [4.2]^{39}$$

This has the desired effect of weighting the projected ozone or $PM_{2.5}$ base design values towards the middle year of a five-year period (2012-2016); in this example, for a 2014 base emissions inventory year. Additionally, an average of three design values will be more stable (less year to year variability) than any single design value period. An EPA analysis of design values data at 761 ozone monitors over the period between 2002 and 2011 concluded that the median standard deviation of individual 3-year ozone design values was 5.3 ppb, whereas the standard deviation of the average of multiple 3-year ozone design values was only 4.0 ppb.

In cases in which there are less than 5 years of valid monitoring data at a site, we recommend that base design values be calculated only when there are at least 3 years of consecutive valid data (i.e., at least one complete design value). If a location has less than 3 consecutive years of

³⁹ For nomenclature purposes, the 3-year design value is referred to by the last year of the averaging period. That is, DV 2014 represents air quality data averaged over 2012, 2013, and 2014 for ozone and $PM_{2.5}$.

valid data, then that site should not ordinarily be used in the modeled attainment test.⁴⁰ An example calculation for DVB is shown in Table 4.1 and includes the number of significant digits to include for ozone and each form of the PM_{2.5} standard.

Table 4.1: Example illustrating the calculation of base design values.

	2014 DV	2015 DV	2016 DV	DVB
O ₃ NAAQS (ppb) ⁴¹	76	76	78	76.7
Annual PM _{2.5} NAAQS (µg/m ³)	12.9	13.1	12.6	12.87
24-hour PM _{2.5} NAAQS (µg/m ³)	32	33	32	32.3

The measured 3-year average design values use the rounding/truncation rules established in 40 CFR part 50 Appendix U (8-hour ozone) and Appendix N (PM_{2.5}). The resultant 5-year weighted average DVB should carry one digit to the right of the decimal point for ozone and 24-hour PM_{2.5} and two digits to the right of the decimal for annual PM_{2.5}.

The EPA also recognizes that the ambient data record may be modified under certain circumstances. For example, air agencies can request that the EPA agree to exclude event-influenced data by demonstrating that these data have been influenced by “exceptional” events and otherwise meet the criteria in the Exceptional Events Rule (81 FR 68216, October 3, 2016). Once an air agency submits an exceptional events demonstration and the EPA concurs with an air agency’s request, the event-influenced data are officially noted and removed from AQS user reports (unless the AQS user specifically indicates that they should be included) and not used to calculate design values. In other cases, data may not qualify for exclusion under the Exceptional Events Rule but Appendix W to Part 51 may provide guidance on considering data which may be influenced by events that are not typical or expected to recur in the future (e.g., wildfires, construction, roadway repairs, or unusual agricultural activities) for certain modeling analyses. Potential event-influenced data may affect future year projections that are part of the modeled attainment demonstration. If potential event-influenced data from the historical

⁴⁰ Monitoring sites with less than 3 years of valid data cannot ordinarily be used to determine attainment status. Therefore, in most cases, those sites should not be used in the attainment demonstration or for regulatory analyses. However, there may be cases where a monitoring site with incomplete data indicates an area of high ozone or PM concentration. Further examination of the monitoring data and modeled response (RRF) in the area is recommended as part of either the monitor-based attainment test or an unmonitored area analysis, as appropriate.

⁴¹ The current ozone NAAQS is defined in units of ppm. However, for ease of use, this document will use ppb units.

record may affect regulatory outcomes, we encourage air agencies to consult with their EPA Regional office to determine how best to handle this situation.

In practice, the choice of the base design value can be critical to the determination of the estimated future year design values (Cohan, 2006) and careful consideration should be given to the selection of the years used in the calculation of base design values. There is no single methodology that can derive a “correct” base design value, but the 5-year weighted average value establishes a relatively stable value that is weighted towards the emissions and meteorological modeling year. In most cases, this provides an appropriate anchor point on which to base the future year design value calculations. Alternate, equally plausible, calculations of base design values may be considered with appropriate justification. Alternate base design values may also be considered as part of the corroborating analyses that comprise the aggregate weight of evidence determination. For instance, one may want to consider establishing the base design value on the highest of the relevant design values to ensure that the emissions measures will yield attainment even in periods with meteorological conditions especially conducive to poor air quality. In addition, in some cases, large year to year emissions changes or highly unusual meteorological conditions may make certain periods/years unsuitable for consideration in the base year period. Consideration of adjustments to the base design value(s) can be made, with appropriate justification, on a case-by-case basis and in consultation with the relevant EPA Regional office.

4.1.2 Calculation of Relative Response Factors

The relative response factor for each monitoring site $(RRF)_i$ is the fractional change in air quality concentrations that is simulated due to emissions changes between a base and a future year emissions scenario. The specific RRF calculation techniques vary by pollutant and are described in more detail in the remainder of section 4 below. The most important consideration associated with the RRF calculation is determining which model values are most representative of the expected air quality change for a given location. This requires consideration of all of the varying changes in hourly pollutant concentrations between the base and future cases and a determination of the most appropriate summary (average) value to apply to the base design value. As with the selection of a base design value, there may be plausible alternative means of calculating the RRFs that can differ from the approaches recommended below (e.g., Kulkarni et al., 2014, Porter et al., 2014). Where justified, alternate RRF calculation techniques can be included as corroborative analyses as part of a weight of evidence determination.

4.2 Modeled Attainment Test for the Primary Ozone Standard

The 8-hour ozone design value is currently calculated as the 3-year average of the annual fourth highest daily maximum 8-hour average concentration for a specific monitor. The standard is

considered to be attained if the observed design value does not exceed the level of the ozone NAAQS⁴². Similarly, the modeled attainment test is considered satisfied when the $(DVF)_i$ is less than or equal to the current NAAQS level. The recommended test is described below.

4.2.1 Model Values to Use in the RRF Calculation

Given the formulation of the modeled attainment test, it is important to identify which model days are best suited for determining the expected air quality response resulting from a set of emissions changes. On any given modeled day, meteorological conditions may or may not be conducive to high concentrations at a monitor. If ozone predicted near a monitor on any particular day is much less than the design value, the model predictions for that day could be unresponsive to controls (e.g., the location could be upwind from most of the emissions in the nonattainment area on that day). If these days are included in the RRF calculation, they will likely lead to a higher RRF (closer to one) and a potential overestimation of the future design value.

Internal EPA analyses (U.S. EPA, 2014a) have shown that model response to decreasing emissions is generally most stable when the base ozone predictions are highest. The greater model response at higher concentrations is likely due to more “controllable” ozone at higher concentrations. In addition, the high model days are selected individually for each monitor. Meteorological conditions that lead to high ozone may differ between monitors in an area. For example, monitors that are typically “upwind” or “downwind” of an area may experience high ozone on different days, depending on the prevailing wind direction. In most urban areas, on days with high ozone concentrations, there is a relatively high percentage of locally generated ozone compared to days with low base case concentrations (U.S. EPA 2014b). Days with low ozone concentrations are more likely to have a high percentage of ozone due to background and boundary conditions. Since the form of the standard is also focused on the highest days of an ozone season (i.e., the fourth highest MDA8), the RRF calculation should also focus on days when the model predicts the highest ozone concentrations.

As the ozone NAAQS has been lowered, a key question is whether the attainment test should use an average RRF based on all modeled days that are greater than the NAAQS, as in the previous guidance approach. In some areas of the country, this could lead to RRF calculations that might include upwards of 100 days per ozone season. In these cases, including too many

⁴² At the time of publication of this guidance, the ozone NAAQS is 0.070 ppm per 40 CFR 50.19. Design values for the 0.070 ppm NAAQS are truncated to the 3rd decimal digit. Therefore, 0.0709 ppm (70.9 ppb) is considered attainment and 0.0710 (71.0 ppb) is considered nonattainment. The same rounding/truncation procedures should be applied in the modeled attainment test. A detailed description of the methodology to calculate ambient ozone design values is provided in Appendix U to Part 50.

days in the RRF calculation may lead to higher (closer to 1) RRFs. Using a reasonable number of the highest modeled days at each monitor is most likely to represent the response of the observed design value at a monitor. Since the design value is based on the seasonal 4th high observed values, we recommend selecting a set of modeled days that are likely to encompass a range of values that are somewhat higher than and somewhat lower than the 4th high value. We, therefore, recommend calculating the RRF based on the highest 10 modeled days in the simulated period (at each monitoring site). We believe this balances the desire to have enough days in the RRF to generate a robust calculation, but not so many days that the RRF does not represent days with concentrations near the observed design values. In addition, use of the highest 10 days (without an initial threshold) allows the attainment test to be easily adapted to any level of the NAAQS with little or no change in the methodology. In support of the revised recommendation, a recent assessment of modeled ozone changes between two ozone seasons (Foley et al., 2014) suggests that the use of the highest 10 days in the mean RRF calculation yields a slightly better estimate of the actual observed ozone change than the previous guidance approach.

The EPA recommends that the ozone RRF calculations be based on the 10 highest days in the base year modeling at the monitor location, as long as the base MDA8 value is greater than or equal to 60 ppb for that day. In cases for which the base model simulation does not have 10 days with MDA8 values greater than or equal to 60 ppb at a site, then EPA recommends using all days where MDA8 $\geq$ 60 ppb, as long as there are at least 5 days that meet the minimum threshold criteria. If there are less than 5 days with MDA8 $\geq$ 60 ppb, EPA recommends that air agencies do not calculate a DVF for the site.⁴³ If the modeled attainment test is based on less than 10 days, then other assessments in the aggregate weight of evidence demonstration will need to be more rigorous to counter the reduced robustness of the modeled attainment test.

In addition, as discussed by Vizuite et al. (2011), there can be days in which the modeled source-receptor relationships may not yield a representative response for a particular cell or array of grid cells. This can result from small inconsistencies between the model representation of transport patterns (or chemical formation) and what actually occurred on that day. In other situations, perhaps the high modeled ozone results from an atypical condition (e.g., in conjunction with a wildfire smoke plume) that is not representative of conditions that led to the area's design value. If there is compelling evidence to determine that a particular day, while being among the 10 highest MDA8 values at a location, is not representative of the expected source-receptor relationship at that location; then that day can be considered for removal from

⁴³ A scenario in which the 5th highest base model MDA8 values is less than 60 ppb either indicates an extremely low ozone site or a site with poor model performance. In either case, projections of DVF values are likely not reliable.

the RRF calculation.⁴⁴ If a day or days are removed, we recommended adding the next-highest modeled day or days from outside the top 10 to maintain the use of 10 days in the RRF calculation. Air agencies should document the evidence that argues for the exclusion of any otherwise-eligible days. As noted earlier, poor model performance on individual days can lead to ratios of future to base ozone that may be biased on those days. For example, underprediction of ozone concentrations may lead to ratios that are unresponsive to emissions controls. Air agencies may want to examine the day- and site-specific model performance for days that are part of the RRF calculation to make sure that they can be appropriately used in calculating the expected response.

4.2.2 Grid Cells to Use in the RRF Calculation

It is recommended that ozone RRF calculations consider model response in grid cells immediately surrounding the monitoring site along with the grid cell in which the monitor is located. There are two primary reasons why we believe it is appropriate to include predictions from grid cells near a monitor rather than just the cell containing the monitor. First, limitations in the inputs and model physics can affect model precision at the grid cell level. Allowing some leeway in the precision of the predicted location of daily maximum ozone concentrations can help assure that possibly artificial, fine scale variations do not inadvertently impact an assessment of modeled ozone response. Second, some ozone monitors and important emission sources may be located very close to the border of a grid cell. Considering multiple cells near a monitor, rather than the single cell containing the monitor, diminishes the likelihood of inappropriate results which may occur from the artificial geometry of the superimposed grid system.

Based on the above considerations, it is recommended that the RRF be based on a 3 x 3 array of cells centered on the location of the grid cell containing the monitor. This is a change from the 2007 guidance (U.S. EPA, 2007), which pre-identified 15 km as an appropriate distance for grid cell proximity to a monitor and, therefore, recommended the selection of RRF grid cells to be contingent upon the chosen model grid resolution (i.e., a finer grid resolution considered a larger array of grid cells to maintain the pre-identified 15 km distance). The revised approach allows for small spatial differences in the response to be considered in the RRF calculation and presumes that the chosen model grid resolution is able to appropriately capture model response at the location of the monitoring site. Additionally, as described in section 4.2.3, the guidance now recommends that the grid cell with the highest base year MDA8 ozone value in the 3 x 3 array be used for both the base and future components of the RRF calculation, as opposed to the 2007 guidance approach, which recommended selecting the peak value in the

⁴⁴ Days that have been removed from the official record as exceptional events should be considered for removal from the RRF calculations.

base and future cases even if they were in different grid cells. The rationale behind this change is that the goal of the modeling is to assess the ozone change at a specific location (i.e., a grid cell representative of a monitor location), independent of how the ozone peak may shift across an area. As the monitor location does not change between the base and future, it stands to reason that the future-year value should come from the same grid cell as the base case.

The selection of grid cells to use in the RRF calculation is especially important in “oxidant limited” areas (i.e., areas where incremental NO_x decreases may lead to ozone increases) because these areas are likely to have grid cells that respond to VOC controls, with NO_x sensitive grid cells nearby (perhaps even in the same 3 x 3 array). The 3 x 3 array methodology could lead to unrealistically small or large RRFs in these locations, depending on the specific case. Internal EPA analyses with a 12 km grid resolution have shown that on average, model-estimated future design values vary by less than 1 ppb when a 1x1 approach is used as opposed to the recommended array, although higher variability can occur (U.S. EPA, 2014a).

While the use of a 3 x 3 array of cells is the recommended approach for the modeled attainment test, air agencies are encouraged to consider the actual spatial scales of the monitors at which the modeled attainment test is being applied. Most ozone monitors are generally sited to be representative of an urban or neighborhood scale. In cases in which the spatial representativeness of a monitoring location is much smaller or larger than the area covered by the 3 x 3 array of cells, air agencies may consider assessing site-specific model response over an alternative grid cell array as part of corroborative analyses that inform the aggregate weight of evidence determination. Additionally, there may be cases where certain cells along the periphery of the 3 x 3 array have different modeled responses than what would be expected at the monitor location at the center of array due to a specific local topographic or geographical feature (e.g., a large water body or a significant elevation change). A potential example of this situation would be an array where several cells are over water and where the meteorological conditions and relevant emissions sources differ substantially from the land-based monitor location. Again, in these types of cases and with appropriate justification, air agencies could consider removing the unrepresentative cells from the calculation.

4.2.3 Sample Modeled Attainment Test Calculation

Once the appropriate RRF days are determined at each site, the calculation is straightforward. RRFs are not calculated on a daily basis, but instead are based on the mean 8-hour daily maximum values on all eligible calculation days. At the last step in the process, the final DVF should be calculated in accordance with the data handling conventions associated with the NAAQS (e.g., truncated to the third decimal in ppm units as per current Appendix U). An example is provided below for a 2016 base year and 2030 future year simulation based on an

annual model simulation. This hypothetical modeled attainment test considers an area with three ozone monitors.

Step 1: Compute site-specific base year design values (DVBs) from observed data at all eligible sites in the area by calculating the average of the design value periods which include the base year inventory year. All averaged values should be rounded to the tenth of a ppb. See Table 4.2 for the calculation in this sample case. The base design value is the average of the 3-year design values for 2016, 2017, and 2018.

Table 4.2: Ambient ozone base design values in example calculation.

Monitoring site	2014 DV (ppb)	2015 DV (ppb)	2016 DV (ppb)	Base design value (ppb)
A	84	79	73	78.7
B	N/A	67	83	75.0
C	86	76	80	80.7

Step 2: Compute site-specific relative response factors (RRFs) from modeled data at all eligible sites (i.e., A, B, and C). This is done by first identifying the 10 days with the highest daily 8-hour maximum ozone concentrations greater than 60 ppb (or subset of days if there are 5-9 days greater than 60 ppb) in the base year. For each of these days, identify the grid cell with the highest base year MDA8 ozone in the 3 x 3 cell array surrounding the monitor cell location and use that value in the calculation of a multi-day average. 10-day averages (where possible) should be calculated for both the base and future simulations. The future case average should be based on MDA8 values paired to the same cell as used in the base average. Figure 4.1 below shows an abbreviated subset of the RRF calculation for 3 days at a single sample site. Model estimates of MDA8 (in ppb) should be calculated to at least four places to the right of the decimal, with the last digit truncated.

Figure 4.1. Example demonstration of daily selections of 8-hour maxima to be used in RRF calculation.⁴⁵

Base

6/21/2014		
60.24	68.15	66.20
73.41	76.26	71.27
67.62	74.02	73.24

6/26/2014		
76.20	75.35	77.41
78.51	76.79	75.92
76.66	75.95	77.21

7/17/2014		
50.22	58.55	56.22
53.47	56.22	51.28
57.76	59.10	53.29

Future

6/21/2014		
56.89	59.22	58.05
63.69	68.46	63.39
61.86	67.16	66.80

6/26/2014		
<u>69.84</u>	67.71	68.14
68.30	66.27	67.95
64.28	65.15	66.58

7/17/2014		
46.80	49.27	48.55
51.91	50.41	50.34
53.62	54.10	50.62

Day 1 (6/21) is straightforward. The daily maximum 8-hour average is > 60 ppb and is in the same cell in both the base and future case.

For day 2 (6/26), the peak location shifts from the base to another cell in the array in the future (underlined cell). However, the center left cell is used for base and future values (paired in space).

Day 3 (7/17) would not be eligible for the RRF calculation because there are no base values > 60 ppb.

Step 3: Once the MDA8 values are selected for each appropriate day for each monitoring site, they should be averaged together over the days while maintaining at least four places to the right of the decimal. The RRF is the ratio of the average future MDA8 values to the average base MDA8 values. Table 4.3 shows an example RRF calculation, using the results from days 1 and 2 from Figure 4.1, plus the other eight (top 10) days in which the daily model predictions were deemed appropriate for RRF calculation. RRF values should be estimated to four decimal places (rounded to the 4th decimal digit).

⁴⁵ Figure 4.1 depicts the modeled ozone in each cell with only two digits to the right of the decimal to make the formatting simpler. The actual cell values used in the calculation should carry at least 4 digits to the right of the decimal.

Table 4.3. Relative response factor (RRF) calculation in example calculation.

Date	Base (ppb)	Future (ppb)
6/21/2014	76.2632	68.4626
6/26/2014	78.5156	68.3089
6/27/2014	75.2235	65.4333
6/28/2014	70.0509	62.7618
7/11/2014	76.3311	68.1865
7/12/2014	81.6739	72.6237
7/13/2014	78.3132	64.5255
8/02/2014	73.6956	69.9670
8/03/2014	75.8379	65.0507
8/21/2014	71.4430	59.3647
Average	75.7348	66.4685
RRF_i	0.8776	

The last step of the process is to multiply all of the site-specific RRFs by the corresponding site-specific DVs and compare the results against the current level of the ozone NAAQS. In the final step, as noted in footnote 34, the design values are truncated to the integer ppb unit. Table 4.4 shows those results, assuming that the sample RRF shown above is for site C in the example. The final DVF for this sample site would be 70 ppb or 0.070 ppm. This would be considered a passing modeled attainment test for an ozone NAAQS of 0.070 ppm.

Table 4.4. Calculation of DVF_i for the three sites in the sample exercise.

Monitoring site	Base design value (ppb)	RRF	Future design value, pre-truncation (ppb)	Final Future design value (ppb)
A	78.7	0.8933	70.3	70
B	75.0	0.9138	68.5	68
C	80.7	0.8776	70.8	70

Note: The “final” future year design value represents the truncated value to compare to the NAAQS. However, it is recommended to retain the tenths (of a ppb) digit in all documentation, so that small ozone changes can be gleaned from control strategy and sensitivity analyses.

4.3 Modeled Attainment Test for the Secondary Ozone Standard

At the time this guidance document was written, the secondary ozone NAAQS is the same as the primary NAAQS. However, in the past, EPA has considered setting a secondary ozone NAAQS that is based on a cumulative measure of ozone concentrations, as opposed to the 3-year average of the annual fourth-highest daily maxima. If EPA were to establish a distinct secondary standard, it is possible that air agencies would need to separately show that the planned emissions reductions would be sufficient to meet both the primary and secondary

NAAQS. If a new secondary standard is subsequently developed, EPA will provide supplemental guidance on how to assess attainment of that new standard at the time of its promulgation.

4.4 What is the Modeled Attainment Tests for the Annual Average PM_{2.5} NAAQS?

Because ambient PM_{2.5} often consists of multiple PM species, the modeled attainment test for PM_{2.5} utilizes both PM_{2.5} and individual PM_{2.5} component species. A separate RRF and a separate concentration representing the base period is calculated for each PM_{2.5} species. In order to perform the recommended modeled attainment test, air agencies should divide observed mass concentrations of PM_{2.5} into 8 components (plus passive mass):

- Sulfates
- Nitrates
- Ammonium
- Organic carbon
- Elemental carbon
- Particle bound water
- Salt
- “Other” primary inorganic particulate matter
- Passively collected mass (blank mass)

To apply the attainment test, air agencies must first have outputs from air quality model simulations for a base year and a future year emissions scenario. We recommend a modeled attainment test which has four basic steps, as described in this section.

Step 1. Compute *observed* quarterly mean PM_{2.5} and quarterly mean composition for each monitor.

Derive base year period quarterly mean concentrations⁴⁶ for each of the major components of

⁴⁶Concentrations should be calculated based on calendar quarters for two reasons. First, the NAAQS is calculated as an annual average of 3 calendar years, so it would be inconsistent to average the data by season (where the winter season would span two calendar years). Second, the monitored data used to calculate design values is averaged on a calendar quarter basis before calculating annual averages.

PM_{2.5}.⁴⁷ This is done by multiplying the monitored quarterly mean concentration of FRM derived PM_{2.5} (40 CFR part 53) by the monitored fractional composition of PM_{2.5} species for each calendar quarter (e.g., 20% sulfate x 15.0 µg/m³ PM_{2.5} = 3.0 µg/m³ sulfate).

Step 2. Using air quality model results, derive component-specific relative response factors (RRF) at each monitor for each calendar quarter.

Use the air quality model predictions to calculate the quarterly mean concentration for each PM_{2.5} component for the base year and future year scenario.⁴⁸ Take the ratio of future to base year predictions for each component. The result is a component-specific relative response factor (RRF).

The RRF for component j at a site i is given by the following expression:

$$(RRF)_{ij} = [C_{ij, \text{projected}}] / [C_{ij, \text{base year}}] \quad [4.3]$$

where $C_{ij, \text{base year}}$ is the quarterly mean concentration predicted at or near the monitoring site⁴⁹ with emissions characteristic of the period used to calculate the base design value for annual PM_{2.5}.

$C_{ij, \text{projected}}$ is the future year quarterly mean concentration predicted at or near the monitoring site.

(e.g., given model predicted mean third quarter base year period sulfate of 10.12 µg/m³ and future year mean third quarter concentration of 8.23 µg/m³, then the third quarter RRF for sulfate is 0.8132).

⁴⁷ The mean species concentrations should be representative of the base period. The default approach to calculate mean species concentrations in SMAT is to use the 3-year average, centered about the base modeling year. These values are used to calculate species fractions by quarter. This differs from the 5-year weighted average design values recommended for base year PM_{2.5} values. However, it is expected that there will be less variation in the species fractions compared to the absolute measured PM_{2.5} concentrations. Alternative species fractions calculations can be considered, as long as they are representative of the expected species fractions during base year period.

⁴⁸ The calculations assume that there is one full year of model outputs.

⁴⁹ For greater (coarser) than 12km grid resolution, use the single grid cell. For 12km or less grid resolution, use the mean of the 3 x 3 array of the grid cells surrounding the monitor.

Step 3. Apply the component specific RRFs to observed air quality to obtain projected quarterly species estimates.

For each quarter, multiply the base year period quarterly mean component concentration (step 1) times the component-specific RRF obtained in step 2. This leads to an estimated future quarterly mean concentration for each component (e.g., $3.0 \mu\text{g}/\text{m}^3$ sulfate $\times 0.8132$ = future sulfate of $2.44 \mu\text{g}/\text{m}^3$).

Step 4. Calculate a future year annual average $\text{PM}_{2.5}$ estimate.

Sum the quarterly mean $\text{PM}_{2.5}$ components to get quarterly mean $\text{PM}_{2.5}$ values. Then average the quarterly mean $\text{PM}_{2.5}$ concentrations to get a future year annual average $\text{PM}_{2.5}$ estimate for each FRM site.

Compare the projected average annual arithmetic mean $\text{PM}_{2.5}$ concentration obtained in Step 4 with $12.0 \mu\text{g}/\text{m}^3$. If the values at all FRM sites are $\leq 12.0 \mu\text{g}/\text{m}^3$, the test is passed.

4.4.1 Ambient $\text{PM}_{2.5}$ Data Used in the Annual $\text{PM}_{2.5}$ Attainment Test

$\text{PM}_{2.5}$ data collected at FRM and FEM sites are used for nonattainment designations. Therefore, we recommend using FRM and FEM data as the base data for projecting future $\text{PM}_{2.5}$ concentrations. As can be seen from the list of steps, the modeled attainment test is critically dependent on the availability of species component mass at FRM sites. This raises several issues. First, the majority of FRM sites do not have co-located chemical speciation network (CSN⁵⁰) samplers.⁵¹ And second, the FRM filter measurements and $\text{PM}_{2.5}$ speciation measurements do not always measure the same mass (Frank, 2006). There are numerous known issues with positive and negative sampling artifacts. These issues are addressed below.

4.4.2 FRM Monitors that Do Not Have Speciation Data

Species concentration data and/or species fractions are needed in order to apply the $\text{PM}_{2.5}$ attainment test. There are approximately 1200 FRM and FEM $\text{PM}_{2.5}$ monitoring sites, but only ~200 urban speciation monitoring sites. This makes it difficult to apply the attainment test at

⁵⁰ References to CSN monitors in this document refers to the overall speciation network which includes both trends sites and SLAMS sites.

⁵¹ There are ~1200 FRM measurement sites and ~200-250 urban speciation sites (trends and SLAMS).

the majority of FRM/FEM sites. There are several possible ways to estimate species concentrations at FRM monitors that lack speciation data. Among them are:

- 1) Use concurrent data from a nearby speciation monitor to estimate species concentrations and/or fractions at one or more FRM sites.
- 2) Use representative speciation data (from a different time period) collected in an area to estimate species data at FRM sites.
- 3) Use interpolation techniques to create spatial fields using ambient speciation data.
- 4) Use interpolation techniques to create spatial fields using ambient speciation data **and** gridded model outputs to adjust the species concentrations based on the modeled spatial gradients.

In general, we recommend using spatial interpolation techniques to estimate species concentrations at FRM sites that do not have speciation data (numbers 3 and 4 above). But in some cases, interpolating data from nearby sites may not be appropriate, may not be feasible, or simply may not be necessary. In the EPA's SMAT, a relatively simple interpolation technique is used to estimate species concentrations at all FRM sites in the country. The analysis uses a Voronoi Neighbor Averaging (VNA) technique (consistent with approach number 3 above). Other interpolations have been done using Kriging and other more complicated methodologies such as "Downscaler" (Berrocal, 2010a and 2010b). Air agencies are encouraged to explore techniques that are most appropriate for their area and situation. EPA's SMAT software is available for air agencies to use as a default technique.

For areas that contain one or more speciation sites, and where FRM sites exhibit very little spatial gradients, it may be appropriate to assume that the speciation site(s) is/are representative of the entire area. For areas that exhibit strong spatial gradients in PM_{2.5} concentrations, air agencies should strongly consider using more sophisticated techniques to estimate species concentrations. Combining ambient data with model output concentrations (number 4 above) may help adjust concentrations in areas with strong gradients, but limited speciation data. This technique has been used extensively to create spatial fields of PM_{2.5} concentrations for the purpose of generating health benefits calculations and other examinations of unmonitored areas (also see section 4.6), but it has generally not been used to generate species fractions at FRM sites. The technique is further limited by uncertainties in the representativeness of the model outputs and emissions inventories.

4.4.3 PM_{2.5} Species Calculations and Definitions

Data analyses (Frank, 2006) have noted that the FRM monitors do not measure the same components and do not retain all of the PM_{2.5} that is measured by routine speciation samplers and, therefore, cannot be directly compared to speciation measurements from the Chemical Speciation Network (CSN).⁵² The FRM mass measurement does not retain all ammonium nitrate and other semi-volatile materials (negative sampling artifacts) and includes particle bound water associated with sulfates, nitrates and other hygroscopic species (positive sampling artifacts). This results in FRM measured concentrations (and percent contributions to PM_{2.5} mass), which may be different than the ambient levels of some measured PM_{2.5} chemical constituents.

Because the FRM data are used to determine compliance with the NAAQS, it is critical to estimate the species composition as measured on the FRM filters. In addition, for the purposes of predicting changes in PM_{2.5} components, constructed PM_{2.5} mass should match the composition of mass retained by the FRM.

The goal is to reconstruct the measured species components so that they add up to the measured FRM mass. This concept can generally be represented by equation 4.4:

$$\text{RCFM}_{\text{FRM}} = [\text{Ammoniated Sulfate Mass}] + [\text{Retained Ammoniated Nitrate Mass}] + [\text{Retained Carbonaceous Mass}] + [\text{Other Primary PM}_{2.5}] + [\text{Other Components}] \quad [4.4]$$

In the above characterization, RCFM_{FRM}, or reconstructed fine mass, and all of the listed chemical components reflect those retained during sampling and equilibration on the FRM's Teflon filter. Sulfate and nitrate mass include associated ammonium, which may be different than assumed ammonium sulfate and ammonium nitrate compounds. Carbonaceous mass includes elemental carbon (EC), organic carbon (OC), and hundreds of different carbon compounds, which are not directly measured, and which may not match the carbon mass in speciated measurement data. Also, sulfates and nitrates include particle bound water associated with these hygroscopic aerosols. In this characterization, other primary PM_{2.5} mass is intended to be a more general term that includes fine soil, and oxides that result from other PM emissions.

⁵² The information in this section applies to the most common samplers in the CSN. The characteristics of the sampler and the analytical procedures used to produce chemical speciation data should be considered in determining which, if any, adjustments are appropriate to make the data useful for comparison to FRM and FEM data.

4.4.4 Recommended Treatment of Species Data

We recommend an adjustment technique based on an FRM mass construction methodology, which results in reduced nitrates (relative to the amount measured by routine speciation networks), higher mass associated with sulfates and nitrates (reflecting water included in gravimetric FRM measurements), and a measure of organic carbonaceous mass, which is derived from the difference between measured $PM_{2.5}$ and its non-organic carbon components (Frank, 2006). This characterization of $PM_{2.5}$ mass also reflects “other” primary inorganic $PM_{2.5}$ and other minor constituents. Frank (2006) terms this approach “sulfate, adjusted nitrate, derived water, inferred carbonaceous material balance approach (SANDWICH).” The resulting characterization provides a complete mass balance. It does not have any unknown mass, which is sometimes presented as the difference between measured $PM_{2.5}$ mass and the characterized chemical components derived from routine speciation measurements. The recommended SANDWICH-based characterizations should yield more accurate assessments of future $PM_{2.5}$ concentrations as measured by FRM monitors, compared to using unadjusted CSN data.

4.4.4.1 Retained Nitrate Mass

The first step in the procedure for identifying FRM mass components is to estimate the retained nitrate mass on the FRM filters. The FRM does not capture all of the semi-volatile components of the ambient air, such as ammonium nitrate. The retained amount of nitrate ion, however, can be estimated by a simple thermodynamic model that involves 24-hr ambient nitrate speciation concentrations (as measured by a standard speciation sampler using a nylon filter preceded by a HNO_3 denuder) together with hourly ambient temperature and humidity. Atmospheric nitrates are highest during the cooler months. Retention on the FRM is also higher during the cooler months and essentially all the nitrates are lost during the summer. The retention does not appear to depend on ambient NH_3 or HNO_3 concentrations. More NO_3 is retained at low temperatures and high humidity, which varies by sampling location and time of year.

Because nitrate retention varies by site and season, a simple ammonium nitrate equilibrium model can be used to predict the amount of nitrates retained on the FRM Teflon filter. As used by Hering (Hering, 1999; Zhang, 1992),

$$\Delta NO_3 (\mu g/m^3) = 745.7/T_R^* \sum_{i=1}^{24} (K_i^{1/2}) \quad [4.5]$$

where ΔNO_3 is the amount of volatilized nitrate mass, T_R is the reference temperature for the sampled air volume in degrees Kelvin, and K_i is the dissociation constant for ammonium nitrate evaluated at the ambient temperature and relative humidity for hour i . The nitrate loss can be predicted for each day, based on hourly temperature and relative humidity data. It must be subtracted from the NO_3 measured at speciation sites to estimate the FRM retained nitrate. The SMAT software is populated with a speciation ambient data file with daily average retained nitrate pre-calculated for all CSN and IMPROVE sites. The analysis uses National Weather Service temperature and relative humidity data from the closest station. Other sources of meteorological data may also be appropriate. Further details on the nitrate loss calculations can be found in Frank (2006).

4.4.4.2 Ammonium Associated with Sulfates and Retained Nitrates

There are several ways to estimate ammonium mass for use in attainment test. The most direct way is to use measured ammonium concentrations from the CSN network (IMPROVE does not measure ammonium ion). A second, more indirect method is to estimate the ammonium associated with nitrate, and to calculate the ammonium associated with sulfate and the degree of neutralization of sulfate (DON), and then use the resulting information to calculate ammonium mass. Due to uncertainties associated with the ammonium measurements and the lack of ammonium measurements in rural areas, this indirect method is recommended as the default attainment test methodology.

To determine the mass associated with nitrates, we assume retained nitrate is all ammonium nitrate. Thus, using the ratio of the molecular weight of ammonium to that of nitrate, the ammonium associated with nitrates (NH_4NO_3) can be derived directly from the estimated retained nitrate (NO_3FRM) as:

$$\text{NH}_4\text{NO}_3 = 0.29 * \text{NO}_3\text{FRM} \quad [4.6]$$

The difference between total FRM NH_4 (amount associated with nitrates and sulfates), termed NH_4FRM , and the measured NH_4 , termed NH_4CSN , is needed to determine the ammoniated form of sulfates as described by equation 4.4. A measurement study by Collett (Collett, 2004) shows that NH_4 may not be completely retained during collection on nylon filters preceded by a nitric acid denuder, such as are used at CSN sites. At several FRM study sites, the CSN NH_4 which is adjusted for evaporated NH_4NO_3 tends to more closely correspond to the measured NH_4 from the FRM Teflon filter. However, for other sites, the measured CSN NH_4 appears to agree with FRM NH_4 .

The available information suggests that using measured ammonium (assuming none is volatilized) may be the best assumption. We, therefore, recommend using unadjusted ammonium, but further analysis of this issue is warranted.

To calculate the ammonium associated with sulfate, we recommend using the degree of neutralization of sulfate (DON). This is defined as the ammonium associated with sulfate (i.e., total ammonium less the ammonium associated with nitrate), divided by sulfate. This reflects the degree to which sulfate has been neutralized by ammonium. The ambient data is such that nearly all of the ammonium data is from urban sites (CSN), but the sulfate and nitrate data is from both urban (CSN) and rural (IMPROVE) sites. This may lead to an overestimation of ammonium concentration in rural areas when ammonium is directly interpolated. Therefore, we recommend using calculated DON with SO_4 and $\text{NO}_{3\text{FRM}}$, and interpolating to each FRM site to get quarterly average concentrations. The interpolated DON and species concentrations are used to calculate $\text{NH}_{4\text{FRM}}$ using the following equation:

$$\text{NH}_{4\text{FRM}} = \text{DON} * \text{SO}_4 + 0.29 * \text{NO}_{3\text{FRM}} \quad [4.7]$$

The indirect calculation of ammonium mass from interpolated fields tends to smooth out the gradients in mass. This is deemed to be beneficial, due to the uncertainty in the measurements.

4.4.4.3 Particle Bound Water

Because ammoniated sulfate and ammonium nitrate are hygroscopic, the retained sulfate and nitrate mass will include water. Particle bound water (PBW) can be estimated using an equilibrium model. The EPA developed an approach using the Aerosol Inorganic Model (AIM) (Clegg, 1998). PBW is derived from quarterly average FRM concentrations of sulfate, ammonium, and nitrate (as described above). Estimated hydronium ion, H^+ , needed to achieve ionic balance is derived from the latter values. The model enables the distribution of water and ions to be calculated between liquid, solid and vapor phases for specific temperature and relative humidity conditions. Typical FRM filter equilibration conditions of 35% RH and 22 deg C (295 deg K) temperature are used to estimate water concentrations at those conditions.

Application of AIM at the specified FRM filter equilibration conditions show that PBW is much more dependent on sulfate concentration compared to nitrate and that the relationship varies somewhat by season. There is proportionally less estimated PBW water for wintertime aerosol which has higher NO_3 and lower SO_4 . The PBW concentrations are also sensitive to the degree

of neutralization of the sulfate particles (determined by the relative concentration of NH_4_{FRM}).

We recommend calculating PBW as a component of $\text{PM}_{2.5}$ mass. The AIM model (or other equilibrium models) can be used, or a regression equation can be developed to simplify the process. For computational convenience, EPA derived a polynomial regression equation fit to the calculated water mass from AIM and the three input values to AIM (sulfate, nitrate and ammonium). The polynomial equation is used in the SMAT software to calculate PBW. See the SMAT User's Guide for more details on the default PBW equation.

4.4.4.4 Salt

In the $\text{PM}_{2.5}$ attainment test methodology, salt is represented as a species which accounts primarily for sea salt at sites near the oceans. The salt species is estimated using the CSN measured Cl^+ ion concentration multiplied by 1.8. The multiplier accounts for the sodium contribution to the species. In areas distant from oceans, measured Cl^+ may represent PM mass that is not associated with salt water. For instance, there may be chloride emissions resulting from various industrial processes. Therefore, the use of measured salt in the attainment test calculations should be evaluated on an individual area/monitor basis.

Measured salt is included by default in the SMAT species ambient data file. The inclusion of modeled salt (and hence an RRF for salt) is optional and can be included if there are accurate modeled salt concentrations. If modeled salt is not included in the SMAT input files, an RRF of 1.0 used in the SMAT calculations.

4.4.4.5 Other Primary $\text{PM}_{2.5}$

The terms "crustal," "fine soil," "major metal oxides," "inorganic particulates," and "other PM," are sometimes used interchangeably. For $\text{PM}_{2.5}$ design value calculations we will refer to this material as "other primary $\text{PM}_{2.5}$ " (OPP). For regional haze calculations, we will continue to refer to this material as "fine soil."

For the purposes of estimating OPP for the $\text{PM}_{2.5}$ attainment test, all measured non-carbon mass that is not organic in nature (not associated with sulfate and/or nitrate) should be counted. As with the other $\text{PM}_{2.5}$ components measured on the FRM filter, there is uncertainty associated with this estimate. The "crustal" or "fine soil" definition from IMPROVE can be used

to estimate OPP⁵³ or an alternative formula can be defined which better estimates the urban nature of the FRM measurements. The IMPROVE definition of “fine soil” accounts for the typical crustal components (and attached mass) that would be expected in remote Class I areas. Fine soil is represented as five elements (Al, Si, Fe, Ti, and Ca) with coefficients to represent various oxides and material, which may be attached to or associated with the major elements. In urban areas, inorganic PM, which is not elemental carbon or associated with sulfate or nitrate, may come from many sources such as re-suspended dust or industrial sources (stack or fugitives). It is generally “crustal” in nature (dominated by silicon), but urban PM is more likely to contain heavy metals and industrial components.

Although the composition of inorganic PM may differ between urban and rural (remote) areas, an alternative equation, similar to the IMPROVE fine soil equation, can be used to estimate OPP for the PM_{2.5} attainment test. The alternative equation is suggested by (Frank, 2006) and uses only four elements. The equation removes aluminum (and accounts for associated mass by increasing the coefficient for Si), due to the fact that aluminum is often missing from the speciation measurements. This allows for more complete data.

The alternative “fine soil” equation is as follows:

$$\text{Other primary PM}_{2.5} \text{ mass} = 3.73 \times [\text{Si}] + 1.63 \times [\text{Ca}] + 2.42 \times [\text{Fe}] + 1.94 \times [\text{Ti}] \quad [4.8]$$

4.4.4.6 Blank mass

The other quantifiable components of PM_{2.5} mass include passively collected mass, represented by a field blank concentration (U.S. EPA, 2002). This appears to constitute a contamination of the filter resulting from handling or contact with the FRM cassette. This value is deemed to be an important constituent of PM_{2.5} mass (it is assumed to not be dependent on pollutant emissions). Based on recently collected ambient QA data, we recommend using a default nominal blank mass value of 0.2 µg/m³ (see the [EPA QA website](#) for more details). This value represents an approximate nationwide network median value. This value can be modified based on local FRM blank mass measurements. The blank mass is assumed to remain constant through time (RRF=1.0).

⁵³ IMPROVE estimates fine soil as: $2.2 \times [\text{Al}] + 2.49 \times [\text{Si}] + 1.63 \times [\text{Ca}] + 2.42 \times [\text{Fe}] + 1.94 \times [\text{Ti}]$

4.4.4.7 Calculation of Carbonaceous Mass

Organic carbon mass is typically estimated from blank corrected speciation data, where organic carbonaceous mass is first estimated by multiplying the organic carbon concentrations by 1.4 or alternative factors to account for the oxygen, hydrogen and other elements associated with ambient carbon particles.

There are many uncertainties in estimating carbonaceous mass from carbon measurements (Turpin, 2001; Chow, 2004). Uncertainties include differences in carbon measurement protocol between urban and rural monitoring locations; a relatively “bumpy” surface of urban carbon concentrations as derived from urban and rural organic carbon measurements; and lack of carbon measurements at all FRM locations. We, therefore, recommend an alternative approach to estimate the organic carbon contribution to PM_{2.5} mass.

The recommended attainment test approach estimates organic carbon by *mass balance*. Precisely measured FRM PM_{2.5} mass (U.S. EPA, 2003) is compared to the sum of its non-organic carbon components. The latter are sulfates, ammonium, nitrates, estimated particle bound water, elemental carbon, estimated other primary PM_{2.5} material, salt, plus 0.2 µg/m³ blank mass as discussed earlier.

This approach estimates retained organic carbon FRM mass and explicitly accounts for the following important and difficult to estimate carbon mass properties: 1) regional and urban-rural differences in the mix of carbonaceous aerosols (i.e., the amount of oxygen, hydrogen, etc); 2) retained water associated with hygroscopic carbon compounds (Saxena, 1996; Yua, 2004); 3) volatile carbonaceous material measured by speciation samplers, but not retained in FRM mass; and 4) uncertainties associated with blank corrections of measured organic carbon.

Organic Carbon Mass by mass balance (**OCM_{mb}**) is defined as,

$$\mathbf{OCM_{mb}} = \mathbf{PM_{2.5}} - \{ [\mathbf{SO_4}] + [\mathbf{NO_{3FRM}}] + [\mathbf{NH_{4FRM}}] + [\mathbf{water}] + [\mathbf{EC}] + [\mathbf{OPP}] + [\mathbf{salt}] + [\mathbf{0.2}] \} \quad [4.9]$$

In this expression, all of the above components represent the mass retained on FRM Teflon filters.

This approach completely accounts for FRM mass⁵⁴ and OCMmb is often greater than the amount that would be derived directly from speciation measurements. Because of uncertainties in speciation measurements and their estimates from interpolated surfaces, setting a lower limit (floor) may be necessary so that the OCMmb is not unreasonably low. In some cases, the OCMmb could be lower than the measured OC or OCM. Since measured OC (without accounting for mass associated with OC) is a conservative minimum estimate of OC mass, we recommend setting the OCMmb “floor” to be equal to measured OC.

There may also be situations where an OCMmb “ceiling” is needed. In remote urban areas with relatively high FRM concentrations that may be surrounded by rural background concentrations, the OC by mass balance technique may apportion 95%+ of the PM_{2.5} mass to OCM. If this is not a reasonable assumption, then a ceiling may be needed to cap the OCM as a percentage of PM_{2.5} mass. Based on measured data (FRM sites with co-located speciation data), it appears that on a quarterly average basis, OCM is rarely more than 80% of total PM_{2.5} mass. This may be a reasonable default ceiling, but a lower value (or in rare circumstances, a higher value) may be more appropriate in some regions of the country.

4.4.4.8 Summary of PM_{2.5} Composition Calculations

The terms of equation 4.10 reflect the final estimated composition of the particles measured by the FRM (for each quarter). Quarterly average FRM mass is equal to the sum of the eight species plus blank mass.

$$PM_{2.5FRM} = \{ [OCMmb] + [EC] + [SO_4] + [NO_{3FRM}] + [NH_{4FRM}] + [water] + [OPP] + [salt] + [0.2] \} \quad [4.10]$$

The recommended order to generate the data is as follows:

- 1) Calculate adjusted nitrate using hourly meteorology and 24-hour average nitrate measurements.

⁵⁴ The OC by mass balance technique assumes that all other mass is accounted for and, therefore, all remaining mass is OCM. This may not always be a good assumption. The results of the technique should be carefully evaluated to ensure that OC mass is not overestimated (and, therefore, other mass components are underestimated). This may be an issue in areas that do not have nearby speciation data and have relatively large concentrations of primary PM_{2.5}. The OC by mass balance technique may inadvertently apportion mass to organic carbon, which may actually be EC or “other” primary PM_{2.5} mass components (such as heavy metals). All available ambient data and modeling data should be used to evaluate the species apportionment results.

2) Calculate quarterly averages for adjusted nitrate, sulfate, elemental carbon, ammonium (or degree of sulfate neutralization (DON)), OPP, salt, and measured OCM⁵⁵.

3) Quarterly average ammonium is calculated from the adjusted nitrate, sulfate, and DON values (if measured ammonium is not used directly).

4) Ammonium, sulfate, and nitrate concentrations are input into the polynomial water equation to derive particle bound water concentrations.

5) Carbon mass by difference (OMCmb) is calculated from the PM_{2.5} mass, adjusted nitrate, ammonium, sulfate, water, elemental carbon, salt, other primary PM_{2.5}, and blank mass values. The sum of the eight species plus blank mass is equal to the FRM mass.

We illustrate application of the recommended test in example 4.4.1.

Example 4.4.1

Given: (1) Area “C” has 2 monitoring sites.

(2) Monitored FRM air quality data show the following average quarterly mean PM_{2.5} concentrations based on a 5-year weighted average of observations from 2012-2016 at each site (values are in $\mu\text{g}/\text{m}^3$).

Table 4.4.1 Quarterly average PM_{2.5} FRM mass concentration ($\mu\text{g}/\text{m}^3$) at 2 example sites

Site	Quarter 1	Quarter 2	Quarter 3	Quarter 4
1	17.21	16.34	20.00	14.76
2	15.39	17.98	18.23	13.76

(3) The area has 1 urban speciation site, which is co-located with FRM site 2. The speciation data is available for the entire time period, but the species concentrations for the 2013-2015 time period have been deemed to be most representative of the 2012-2016 5- year weighted average. Therefore, the species data for the average 3-year period (2013-2015) has been

⁵⁵The measured OCM is only used to calculate the “floor” for OCMmb.

interpolated to derive estimated species concentrations at each site. The species concentrations are matched up with FRM data for the same 2013-2015 period to derive representative species fractions. The average monitored air quality for the 3rd quarter of 2013-2015 at site 1 is as follows⁵⁶:

Table 4.4.2 Average monitored 3rd quarter ambient data at site 1

FRM Mass (µg/m3)	Blank Mass (µg/m3)	Non-blank Mass (µg/m3)	Sulfate (µg/m3)	Nitrate (µg/m3)	Organic Carbon Mass (µg/m3)	Elemental Carbon (µg/m3)	Water (µg/m3)	Ammonium (µg/m3)	Salt (µg/m3)	OPP (µg/m3)
22.62	0.2	22.42	8.51	1.11	5.21	0.91	2.31	3.31	0.35	0.71

The blank mass is subtracted before species fractions are calculated because the blank mass is held constant at 0.2 µg/m3 throughout the analysis. In the example, the measured FRM mass for quarter 3 is 22.62 µg/m3. The non-blank FRM mass is 22.42 µg/m3. The mass of the eight species add up to the non-blank mass.

(4) Species fractions are calculated for each quarter for each species. In the example below, a fraction of non-blank mass is calculated for each of the eight species. Blank mass remains fixed at 0.2 µg/m3.

Table 4.4.3 3rd quarter average species fractions for 2013-2015 at site 1

FRM Mass (µg/m3)	Blank Mass (µg/m3)	Non-blank Mass (µg/m3)	% Sulfate	% Nitrate	% Organic aerosol	% Elemental Carbon	% Water	% Ammonium	% Salt	% OPP
22.62	0.2	22.42	37.96	4.95	23.24	4.06	10.30	14.76	1.56	3.17

The percentages in table 4.4.3 above are the relative composition for the 3rd quarter of 2013-2015. It is assumed that these species fractions are representative of the 2012-2016 time-period.⁵⁷

⁵⁶ The species concentrations can be derived from co-located speciation data, nearby speciation data or from interpolated spatial fields. FRM mass is not interpolated.

⁵⁷ The default assumption is that the average of the middle 3 years of speciation data is representative of the 5-year weighted average FRM data. However, other assumptions (number of years of speciation

(5) The weighted quarterly average FRM design values are used as the base year FRM value for each monitoring site (2012-2016). The species fractions from the 2013-2015 speciation data were used to estimate the species concentrations for the base year FRM PM_{2.5} data. The percentage compositions for 2013-2015 are applied to the quarterly weighted average design values as shown in table 4.4.4. In the example below, the weighted average design value for the 3rd quarter for the site from table 4.4.1 is 20.00 µg/m³. This leads to the following concentrations of PM_{2.5} species:

Table 4.4.4 Calculation of the “base case” species concentrations at site 1

Weighted Avg. FRM Mass (µg/m ³)	Blank Mass (µg/m ³)	Non-blank Mass (µg/m ³)	Sulfate (µg/m ³)	Nitrate (µg/m ³)	Organic aerosol (µg/m ³)	Elemental Carbon (µg/m ³)	Water (µg/m ³)	Ammonium (µg/m ³)	Salt	OPP (µg/m ³)
20.00	0.2	19.80	7.52	0.98	4.60	0.80	2.04	2.92	0.31	0.63

This procedure is repeated for each PM_{2.5} site and quarter to complete the calculation of base year ambient concentrations used as the basis for future estimates of PM_{2.5} mass and its components.

data) can be used. It is generally assumed that the inter-annual variability of the species fractions is small compared to the variability of species concentrations.

(6) Modeled results show the following relative response factors (RRF) for predicted mass of 5 components of PM_{2.5} for the 3rd quarter⁵⁸:

Table 4.4.5 3rd quarter modeled RRFs for site 1

RRF Sulfate	RRF Nitrate	RRF Organic aerosol	RRF Elemental Carbon	RRF Salt	RRF OPP
0.8761	0.9432	0.9713	0.9324	1.0	1.0423

(7) The quarterly mean RRFs from table 4.4.5 are multiplied by the weighted quarterly average species concentrations from table 4.4.4 to derive future year concentrations.

From the example above, the future year 3rd quarter concentrations are:

$$\text{Sulfate}_{\text{Future}} = 7.52 * 0.8761 = 6.58 \mu\text{g}/\text{m}^3$$

$$\text{Nitrate}_{\text{Future}} = 0.98 * 0.9432 = 0.92 \mu\text{g}/\text{m}^3$$

$$\text{Organic carbon mass}_{\text{Future}} = 4.60 * 0.9713 = 4.47 \mu\text{g}/\text{m}^3$$

$$\text{Elemental Carbon}_{\text{Future}} = 0.80 * 0.9324 = 0.75 \mu\text{g}/\text{m}^3$$

$$\text{Salt}_{\text{Future}} = 0.31 * 1.0 = 0.31 \mu\text{g}/\text{m}^3$$

$$\text{OPP}_{\text{Future}} = 0.63 * 1.0423 = 0.65 \mu\text{g}/\text{m}^3$$

(8) The future year concentrations derived above are used to calculate the future year concentration of ammonium (if the direct ammonium RRF is not used) and particle bound water.

The future year ammonium concentrations are calculated from the sulfate, nitrate, and (base year) DON values. Assuming that the DON is unchanged from the base year⁵⁹, the ammonium is

⁵⁸ The default assumption for the annual average PM_{2.5} NAAQS test is to calculate RRFs from the mean of the 3 X 3 matrix of grid cells surrounding each FRM monitoring site.

⁵⁹ Due to the uncertainty in the ammonium measurements, by default, the DON is assumed to stay constant through time. The water calculation is sensitive to the ammonium (and, therefore, the DON value) concentrations. Holding the DON constant allows for the future year ammonium and water values to be solely a function of the change in sulfate and nitrate concentrations. Otherwise, the water concentration can go up when the sulfate and nitrate concentrations go down (and vice versa). This may occur if sulfate becomes more neutralized in the future. It is a somewhat illogical outcome (although scientifically possible) and is highly dependent on an uncertain measurement (ammonium). Therefore,

calculated using the following formula:

$$\text{NH4}_{\text{future}} = \text{DON} * \text{SO4}_{\text{future}} + 0.29 * \text{NO3}_{\text{future}}, \quad [4.7]$$

In the example above, assuming the base year DON is 0.336,

$$\text{Ammonium}_{\text{Future}} = 0.336 * 6.58 + 0.29 * 0.92 = 2.48 \mu\text{g}/\text{m}^3$$

The $\text{NH4}_{\text{future}}$, $\text{SO4}_{\text{future}}$, and $\text{NO3}_{\text{future}}$ concentrations can then be input into an equilibrium model (AIM or another alternative model) or through a polynomial regression equation to predict future year particle bound water concentration (based on the default equation, the future year water concentration in this case is $1.73 \mu\text{g}/\text{m}^3$).

(9) The future species concentrations at each FRM site are then summed over the eight species plus blank mass to estimate the future quarterly average $\text{PM}_{2.5}$ concentration.

In the example above, the total $\text{PM}_{2.5\text{Future}} =$
 $6.58 + 0.92 + 4.47 + 0.75 + 0.65 + 2.48 + 1.73 + 0.2 = 17.78 \mu\text{g}/\text{m}^3$

(10) The same calculations are completed for the other 3 quarters to get a future year $\text{PM}_{2.5}$ concentration for each quarter. The 4 quarters are then averaged to get a final future year annual average $\text{PM}_{2.5}$ concentration for each FRM site.

(11) The future year annual average concentration is compared to $12.0 \mu\text{g}/\text{m}^3$.⁶⁰

4.5 What Is the Recommended Modeled Attainment Test for the 24-Hour NAAQS?

Our recommended modeled attainment test for the 24-hour NAAQS for $\text{PM}_{2.5}$ is similar to the previously described test for the annual NAAQS in that it uses model predictions in a relative

use of a constant DON creates a more stable set of calculations. If the measured and modeled ammonium concentrations are believed to be accurate and respond in a reasonable way to emissions controls, then it would be more scientifically credible to use the model predicted change in ammonium. Otherwise, it is a reasonable assumption to keep the DON constant over time.

⁶⁰ In the final step, the future year concentration should be rounded to the tenths digit. A (rounded) value of $12.0 \mu\text{g}/\text{m}^3$ meets the NAAQS. A value of $12.1 \mu\text{g}/\text{m}^3$ or greater violates the NAAQS.

sense to reduce site-specific *observations* (averaged over 5 years). In the test, we are interested in reducing the base year design values at each site to $\leq 35 \mu\text{g}/\text{m}^3$ (the 2006 24-hour $\text{PM}_{2.5}$ NAAQS).⁶¹

Ideally, the modeled attainment test should reflect model results obtained for days in each season having observed $\text{PM}_{2.5}$ concentrations above the design value. Even though the 24-hour NAAQS is based on the single 98th percentile value of all days in the year, it is important to perform the test on a seasonal basis, since $\text{PM}_{2.5}$ consists of a mixture of pollutants whose composition can vary substantially from season to season. There could be a substantial amount of uncertainty associated with predictions on any single day. Thus, our test is most likely to be reliable when relative response factors (RRFs) reflect composite responses from multiple days. Therefore, we recommend modeling as many days as feasible where observed $\text{PM}_{2.5}$ is greater than $35 \mu\text{g}/\text{m}^3$. Alternatively, the test can focus on the high end of the distribution of days in each quarter⁶² (e.g., the top 10% of $\text{PM}_{2.5}$ days⁶³) assuming that the high days are representative of days that violate the NAAQS. As with the annual NAAQS (and for the same reasons), the preferred approach is to develop RRFs, which are quarter specific⁶⁴.

The 24-hour $\text{PM}_{2.5}$ attainment test should be based on the same 5-year weighted average methodology that was used for the annual standard, with some slight modifications. The 24-hour design values are calculated from the 98th percentile value for each year. In the 24-hour $\text{PM}_{2.5}$ calculations, the 98th percentile value from each year is used in the final calculations. Since the 98th percentile value can come from any day in the year, all quarters and years should be carried through to near the end of the calculations. To calculate final future year design

⁶¹ See 71 FR 61224 and 40 CFR 50.13.

⁶² Similar to the annual $\text{PM}_{2.5}$ NAAQS, the default recommended procedures for the 24-hr NAAQS assume handling of the ambient data and model data on a calendar quarter basis. However, in some nonattainment areas, 24-hr $\text{PM}_{2.5}$ NAAQS exceedances may occur during a very limited time of the year or season. Processing the data (both ambient and model) on a sub-quarterly basis may be appropriate in certain circumstances.

⁶³ For most sites, the top 10% of monitored days per quarter will represent between 3 and 8 ambient measurement days.

⁶⁴ In some areas it may not be necessary to model and evaluate the 24-hour NAAQS for all quarters. For example, if observed $\text{PM}_{2.5}$ concentrations only exceed the NAAQS in the 1st and 4th quarters, and concentrations in the 2nd and 3rd quarters are very low, then it may not be necessary to model the full year. But for areas that have monitored violations (or high values that are close to the NAAQS) in all four seasons, the entire year should be evaluated.

values, the 98th percentile day for each year is identified and then a 5-year weighted average of the 98th percentile values for each site is calculated to derive the future year design value.⁶⁵ In nonattainment areas that measure violations of the daily PM_{2.5} NAAQS in multiple seasons (most often summer and winter), the highest PM days can sometimes shift between seasons when days are projected to the future. A consequence of this shift is that a base year 98th percentile winter day may have a higher future year concentration than a summer day that started with a higher concentration in the base year. Therefore, the recommended attainment test methodology has been designed so that the temporal distribution of high days in the base and future periods can shift between quarters.

In the 24-hour attainment test methodology (described below), the eight highest ambient PM_{2.5} days in each quarter at each site are projected to the future (32 days per year) using species specific quarterly RRFs. After all 32 days are projected to the future, the days are re-ranked to determine the future year 98th percentile day.⁶⁶ The rank of the future year 98th percentile day is selected based on the rank of the observed 98th percentile day in the base year ambient data (which depends on the number of valid daily samples). For example, at monitoring site A, if there are 120 observations in year 1 then the 98th percentile day is the 3rd high observation day for the year. In that case, the future year 98th percentile day is selected as the 3rd high future day for the year (out of the 32 highest days).

Similar to the annual PM_{2.5} attainment test, we recommend interpolation techniques for FRM monitors that do not have co-located speciation data. Because the 24-hour standard is a 98th percentile-based value, the species composition on high concentration days may be highly variable from day to day and from site to site. Therefore, while interpolation techniques may be needed, we strongly recommend collecting speciation data at all FRM sites that violate the 24-hour NAAQS. A precise estimate of the PM_{2.5} components at violating sites will help reduce uncertainty in projecting the future year concentration estimates.

⁶⁵ Similar to the annual average PM_{2.5} attainment test, design values are calculated for consecutive 3-year periods. From the 5-year base period, three design values are calculated and then averaged together to create a 5-year weighted average.

⁶⁶ The observed 98th percentile day is always between the 1st and 8th high for the year, depending on the sampling schedule. Therefore, projecting the 8 highest days in each quarter ensures that the observed 98th percentile day is always captured. Additional days could be projected, but a maximum of 32 days per year is needed to guarantee that the 98th percentile observation day at each site is projected to the future.

We recommend a modeled attainment test for the 24-hour PM_{2.5} NAAQS with the following steps.

Step 1. Identify the high observed PM_{2.5} days at each FRM monitoring site for each year.

The first step in projecting the daily design value is to identify at each FRM site, the eight highest observed 24-hour PM_{2.5} concentration days in each quarter for each year of the base period (up to 5 years), and identify the day rank of the observed 98th percentile value for each year based on the number of collected ambient samples (i.e., 3rd highest day of the year). This results in a data set containing 32 days of data for each year (for up to 5 years) for each site.⁶⁷

The test should be performed for each monitoring site that meets the data completeness criteria for calculating a design value for the 24-hour NAAQS. There may not always be data available for all four quarters and all 5 years. We recommend using 8 days per quarter because the 98th percentile day for a year is always one of the 8 highest days of the year.⁶⁸ If all of the high days occur in a single quarter, then using the 8 highest days from each quarter will ensure that the actual 98th percentile day is always captured. This may result in processing more days than necessary, but effectively limits the future year design value calculations to a reasonably small number of days.

Step 2. Calculate “high days” species fractions for each quarter for each FRM monitor.

In this step, quarterly ambient species fractions on “high” days are calculated for each of the major component species of PM_{2.5} (i.e., sulfate, nitrate, ammonium, elemental carbon, organic carbon mass, particle bound water, salt, and blank mass). This calculation is performed by dividing the average monitored concentrations of FRM-derived total PM_{2.5} mass on the high PM_{2.5} days at each site for each quarter, by the average monitored species concentration on the high PM_{2.5} days for each quarter.⁶⁹ The default recommendation for identification of “high”

⁶⁷ The methodology does not assume that the temporal distribution of high days in the base and future periods will remain the same. We recommend projecting at least 8 ambient days per quarter from the base period to the future and then re-rank the entire set of days to find the new future year 98th percentile value (for each year).

⁶⁸ If there are 365 samples in a year, then the 98th percentile is the eighth high day.

⁶⁹ Similar to the annual average calculations, for FRM sites that do not have co-located species data, we recommend calculating the quarterly species fractions using interpolated species data. For the 24-hour species interpolations, we recommend interpolating the average of the highest 10% of monitor days in each quarter.

days is the top 10% of days in each quarter. This results in a relatively robust calculation, which typically uses between 3 and 9 days per quarter (depending on the sampling frequency). The end result is a set of quarterly “high days” species fractions for each FRM site.

Step 3. Calculate species concentrations for each of the high ambient days.

Multiply the quarterly “high day” species fractions from step 2 by the PM_{2.5} mass concentration for the 8 high days per quarter identified in step 1. This results in a set of species concentrations for each of the 32 days per year identified in step 1.

Step 4. Calculate component specific RRFs for the high days in each quarter.

For each quarter, calculate the ratio of future year to base year modeled predictions for sulfate, nitrate, elemental carbon, organic carbon, salt, and OPP for the top 10 percent of modeled PM_{2.5} days based on modeled concentrations of 24-hour average PM_{2.5}. The result is a set of species-specific “high day” RRFs for each quarter.

The relative response factor for component j at a site i is given by the following expression:

$$(RRF)_{ij} = ([C_{j, \text{projected}}]/[C_{j, \text{base year}}])_i$$

where $C_{j, \text{base year}}$ is the base year mean species concentration (for the high modeled PM_{2.5} days for each quarter) predicted at the (single) grid cell which contains monitoring site_i.

$C_{j, \text{projected}}$ is the future year mean species concentration (for the high modeled days for each quarter) predicted at the (single) grid cell which contains monitoring site_i.

For example, assume that base year predicted sulfate mass on the 10 percent highest PM_{2.5} days for quarter 3 for a particular location is 20.0 µg/m³ and the future year modeled sulfate concentration is 16.0 µg/m³, then the RRF for sulfate for quarter 3 is 16.0/20.0 or 0.80. Due to potentially large spatial and temporal gradients, we recommend 24-hour PM_{2.5} NAAQS RRFs to be calculated based on the modeled concentrations at the single grid cell where the monitor is located.

Step 5. Apply the component specific RRFs to observed air quality by quarter.

For each of the 8 days in each quarter, multiply the daily species concentrations from step 3 by the quarterly species-specific RRFs obtained in step 4. If there is 1 modeled base year, then there will be four quarterly RRFs at each monitor. The modeled quarterly RRF for quarter 1 is multiplied by the ambient data for quarter 1 (8 days in each year) for each of the 5 years of ambient data. For example, for day A, $21.0 \mu\text{g}/\text{m}^3 \text{ nitrate} \times 0.75 = \text{future nitrate of } 15.75 \mu\text{g}/\text{m}^3$. The same procedure is applied for the 8 high days per quarter in the other 3 quarters. This leads to an estimated future concentration for each component for each day.

Step 6. Calculate remaining future year PM_{2.5} species.

The future year concentrations for the remaining species are then calculated for each of the days.⁷⁰ Similar to the annual PM_{2.5} attainment test, we recommend that the future year ammonium is calculated based on the future year sulfate and nitrate concentrations, using a constant value for the degree of neutralization of sulfate (from the ambient data). The future year particle bound water concentration is then calculated from an empirical formula derived from the AIM model. The inputs to the formula are the future year concentrations of sulfate, nitrate, and ammonium calculated in step 5.

Step 7. Sum the species components to get total PM_{2.5} concentrations for each day.

Sum the species concentrations for each day to obtain total PM_{2.5} values for the 32 days per year per site.

Step 8. Determine future year 98th percentile concentrations for each site year.

Sort the 32 days for each site for each year by total PM_{2.5} concentration. For each site year, the monitored 98th percentile rank (for each year) is used to identify the 98th percentile rank for each year.⁷¹ For example, if the base year 98th percentile value for year 1 was the 3rd high concentration, then the future year 98th percentile concentration is identified as the 3rd high future year PM_{2.5} concentration (out of the 32 days).

⁷⁰ If salt is not explicitly modeled, then the salt RRF should be held constant. Blank mass is assumed to be constant between the base and future year.

⁷¹ This assumes that the ambient sampling schedule (and number of samples) would remain the same between base and future years.

Step 9. Calculate future 5-year weighted average 24-hour design values and compare to the NAAQS.

The estimated 98th percentile values for each of the 5 years are averaged over 3-year intervals to create 3-year average design values (e.g., the 98th percentile values from year 1, year 2, and year 3 are averaged. Then the 98th percentile values from year 2, year 3, and year 4 are averaged, etc.). These design values (up to 3) are then averaged to create a future year 5-year weighted average design value for each monitoring site.

The preceding steps for determining future year 24-hour PM_{2.5} concentrations are applied for each FRM site. The 24-hour PM_{2.5} design values are truncated after the first decimal place. This approach is consistent with the truncation and rounding procedures for the 24-hour PM_{2.5} NAAQS. Any value that is greater than or equal to 35.5 µg/m³ is rounded to 36 µg/m³ and violates the 24-hour NAAQS. Similarly, a value of 35.4 µg/m³ is rounded down to 34 µg/m³ and is attaining the 24-hour NAAQS.

4.6 Local Area Analyses - Special Considerations for Primary PM_{2.5}

Primary PM does not undergo chemical transformation between being emitted and its arrival at a receptor location. Thus, high concentrations of primary PM can occur without relatively lengthy travel times from source to receptor. Unlike secondary PM or ozone, we would expect concentrations of primary PM to increase the closer one gets to the source(s) of emissions. Therefore, if a designated nonattainment area contains concentrated sources of primary PM, we would expect there to be relatively large spatial gradients near sources of the primary portion of the organic carbon, elemental carbon and other PM components of ambient PM_{2.5} (these localized areas of high concentrations are often called “hotspots”).

Note that the PM_{2.5} NAAQS ambient monitoring rule language⁷² indicates that some monitoring locations may not be comparable to the annual PM_{2.5} NAAQS. PM_{2.5} measurement data from monitors that are not representative of “area-wide” air quality, but rather of relatively unique micro-scale, or localized hot spot, or unique middle-scale impact sites, are not eligible for comparison to the annual PM_{2.5} NAAQS. The ambient air quality monitor siting rules define the appropriate scales of influence for the PM_{2.5} monitoring network.⁷³

⁷² See 40 CFR 58.30.

⁷³ See 40 CFR part 58, Appendix E.

4.6.1 Analysis of Primary PM_{2.5} Impacts at Monitors

The majority of FRM and FEM PM_{2.5} monitors are located at “urban scale” sites. These sites tend to represent relatively large spatial scales and do not have large gradients compared to other monitors in the area. Some sites are classified as “neighborhood” scale and may be influenced by more local sources. There are also near-road sites that have specifically been sited to measure gradients that may exist near heavily travelled roads. For reasons stated above, local influences creating large spatial gradients are likely to consist mostly of primary PM_{2.5} (OC, EC, and OPP). These sources may be point sources, or they may be nearby roads or other mobile or area sources.

As part of the attainment demonstration modeling, it may be necessary to evaluate the local-scale impacts of primary PM_{2.5} sources for contributions to the 24-hour and/or the annual NAAQS. As stated earlier, for the purposes of determining attainment with the NAAQS, it may not always be appropriate to compare ambient data from PM_{2.5} monitoring sites that are dominated by point sources to the annual NAAQS. But there are numerous cases where local source contributions may not be dominant, but are a sizable contributor to total PM_{2.5} (~10-30% of total annual average PM_{2.5}). In these cases, a more refined analysis of the contribution of local primary PM_{2.5} sources to PM_{2.5} at the monitor(s) will help explain the causes of nonattainment at and near the monitor and may lead to the more efficient ways to attain the NAAQS by controlling emissions from local sources which may be important contributors to the violating area.

There are several modeling tools that can be used to evaluate contributions of local PM_{2.5} sources. A grid model can be run at very high horizontal resolution (1 or 2 km or finer) or a Gaussian dispersion model can be used. Grid based models simulate chemical transformation and complex meteorological conditions, while dispersion models are generally more simplistic; being limited to a local-scale, using Gaussian approximations with little or no chemistry. Therefore, while dispersion models may not be an appropriate tool for determining secondary PM_{2.5} or ozone concentrations, they work well for use in determining local primary PM_{2.5} impacts. The model(s) and model setup should be evaluated to determine the most appropriate tools for a specific situation. Regardless of which type of models are used to evaluate changes in primary PM_{2.5} at monitoring locations, we recommend that the model results be used in a relative manner. This is consistent with the already described attainment tests. If a grid model is used at very high resolution, the attainment test as described in sections 4.4 and 4.5 should be followed. If a Gaussian dispersion model is used, then the application of the attainment test

will vary slightly. The test will need to combine results from the chemical transport grid based modeled attainment test and the results from local-scale dispersion modeling. Because each nonattainment area has unique emissions sources and source-receptor relationships, air agencies should work closely with their EPA Regional office in developing local area analysis applications. The nature of the analyses and calculations of $PM_{2.5}$ concentrations (base and future) depend on the type(s) of local sources, measured PM gradients, the NAAQS being examined, and the model(s) used.

4.6.2 Analysis of Primary $PM_{2.5}$ Impacts at Monitors Using a Gaussian Dispersion Model

To apply a dispersion model in an attainment test, it is important to determine the local component of primary $PM_{2.5}$ at the monitor and the sources that are contributing to this component. There is no single, simple method for quantifying this contribution, but detailed analysis of ambient data and advanced data analysis techniques such as receptor modeling may help quantify the contribution. EPA provides [software and information on the CMB, UNMIX, and PMF receptor models](#).

The simplest method for identifying the local component of $PM_{2.5}$ is to examine local ambient $PM_{2.5}$ concentrations. For this type of analysis, it is important to identify the local contributions from as small a source area as possible. This will make it easier to identify contributing sources. One aspect of this analysis is to examine monitored concentration differences between urban monitors (with the highest concentrations) and more suburban measurements. This is likely to provide a representative indication of the excess contribution from a relatively local area. “Urban excess” calculations which pair an urban monitor with an appropriate rural background monitor (U.S. EPA, 2004b) are likely to indicate “local” contributions that may be representative of a metropolitan area. In most cases, the local component will include contributions from more than one source.

Sources identified as contributing to the monitor through emissions analysis or data analysis (such as receptor modeling) can then be modeled with a dispersion model (or alternatively, a very high resolution grid model). It is common practice to run dispersion models for a limited number of major point sources or line sources in relatively small areas (out to a maximum

distance of ~50 km).⁷⁴ Dispersion models can also be run for all sources of primary PM_{2.5} in a limited area (including mobile, non-road, and area sources).

When applying a model to evaluate the impacts from emissions of primary PM_{2.5}, one should determine the PM_{2.5} species that make up the local primary PM.⁷⁵ We recommend that the individual components of primary PM_{2.5} be tracked separately. This will allow for a more thorough evaluation of the modeling results (comparing model output to speciated ambient data) and may aid in the development of primary PM_{2.5} control strategies.

The majority of the primary PM_{2.5} will consist of the primary portion of the organic carbon component, elemental carbon (EC), and the general category of “other primary particulate matter” (OPP). Speciated PM_{2.5} measurements may be able to identify some of the more important “other” inorganic components such as heavy metals or salt. In some cases, directly emitted sulfate (and in rare cases nitrate) may also be a significant component of the local primary PM_{2.5}.

As part of a local-source impact analysis, an estimated concentration or fraction of primary OC may be needed. There are several methods available for estimating the primary versus secondary portion of ambient OC. Among these are the EC tracer method and receptor modeling. The EC tracer method is the most common method used to estimate secondary and primary OC concentrations (Turpin, 1995), (Strader, 1999), (Cabada, 2004), (Chu, 2005), (Saylor, 2006). The method uses measurements of OC and EC and calculated OC to EC ratios to identify periods when OC is likely to be mostly primary. This information is then used to calculate the secondary contribution to OC. Receptor models such as CMB and PMF have also been used to estimate secondary organic concentrations (Na, 2004), (Yuan, 2006).

Because each nonattainment area has unique emissions sources and source-receptor relationships, air agencies should work closely with their EPA Regional office in developing local area analysis applications.

⁷⁴ This guidance document only applies to PM_{2.5} attainment demonstrations to satisfy requirements in CAA Section 189. Other guidance documents and procedures are applicable for SO₂, NO₂, CO, and/or Pb attainment demonstrations and/or PM_{2.5} permitting applications.

⁷⁵ The PM_{2.5} emissions should be broken out into individual species using the best information available. Typically, SCC specific speciation profiles are used to “speciate” the PM into individual components. Local, source specific information should be used whenever possible.

4.6.2.1 Double Counting

Application of a local area analysis may result in double counting of local emissions sources and reductions. This can happen when a change in emissions is examined with both a dispersion model and a chemical transport model.

The potential for double counting can be evaluated by considering the grid resolution of the chemical transport model and the number of sources in the dispersion model. The finer the resolution of the grid model, the more double counting may be a problem (because the local sources will be more finely resolved). Additionally, the more sources that are run with the dispersion model, the more double counting may be a problem. If the grid cell size is relatively large (e.g., 12km) and the primary emissions are relatively small, it may be possible to assume that double counting is small enough to be ignored. But the nature of the issue should be evaluated on a case by case basis.

The simplest way to evaluate the magnitude of the problem is to run the chemical transport model with and without the sources from the dispersion model. This will indicate the maximum impact that the sources can have on the chemical transport modeling results. A very small impact means that double counting is not a problem. A large impact indicates that a more explicit analysis is needed in order to resolve double counting issues.

4.6.2.2 Analysis of Primary PM_{2.5} at Monitors- Quality Assurance

As with any modeling exercise, it is important to quality assure the model inputs and outputs. In particular, we recommend focused quality assurance checks on emissions from sources flagged for a dispersion modeling analysis. Prior to applying a model, air agencies should review available information to ensure that there are no major discrepancies between modeled estimates and nearby monitored data for PM. The emission factors, activity data, and speciation profiles of the PM_{2.5} emissions should also be analyzed for accuracy. If a speciation monitor exists, the speciated data from the monitor can be compared to the speciation profiles of the flagged sources. Receptor models can also be used as a QA tool. Discrepancies between receptor modeling results (which are based on analyzing ambient data) and speciated emissions may indicate a problem with the magnitude and/or the speciation of the emissions sources. If discrepancies are found, those implementing the modeling protocol (see section 2.1) should consult with the appropriate EPA Regional office to reach agreement on what, if any, adjustments should be made to the emissions estimates for the identified sources.

It is also important to quality assure the model outputs. Modeling each species of primary PM_{2.5} separately within the dispersion model should aid in this analysis, especially if the selected control strategies applied in the future year do not control each primary species to the same degree. If a speciation monitor exists, the speciated data from the monitor may also help quality assure the dispersion model results. However, the application of the dispersion model results in a relative sense will help to reduce the impact of possible over- or under-estimations by the dispersion model due to emissions, meteorology, or general selection of other model input parameters.

4.7 Estimating design values at unmonitored locations

High ozone and/or PM_{2.5} concentrations can occur at (or near) existing ambient monitors or in unmonitored areas. The modeled attainment test is primarily a monitor-based test. As such, the focus of the attainment test is whether attainment can be reached at existing monitors. An additional “unmonitored area analysis” can also be performed to examine ozone and/or PM_{2.5} concentrations in unmonitored areas. The unmonitored area analysis is intended to be a means for identifying high ozone and/or PM_{2.5} concentrations outside of traditionally monitored locations, particularly in nonattainment areas where modeling or other data analyses have indicated potential high concentration areas of ozone and/or PM_{2.5} outside of the existing monitoring network. An unmonitored area analysis may also be more important in areas where the ozone or PM_{2.5} monitoring networks just meet or minimally exceed the minimum required network in a nonattainment area.

This review can help ensure that a control strategy leads to reductions in ozone or PM_{2.5} at other locations which could have base case (and future) design values exceeding the NAAQS were a monitor deployed there. In addition, analysis of concentrations in unmonitored areas may serve other purposes such as helping to site new (or move existing) monitors, examining health benefits from emissions reductions, and analyzing the impact of potential new or modified emissions sources. This document describes how an unmonitored area analysis can be performed for a particular area. See the respective ozone and PM_{2.5} SIP Requirements Rules (including the preambles and response to comments documents) for more information on when an unmonitored area analysis is recommended or required.

We use the term “unmonitored area analysis” to describe an analysis that uses a combination of model output and ambient data to identify areas that might exceed the NAAQS in areas that are not currently monitored. An unmonitored area analysis for a particular nonattainment area is intended to address the potential for air quality problems within or near that nonattainment

area. The analysis should include, at a minimum, all nonattainment counties and counties surrounding the nonattainment area, as appropriate. It is possible that unmonitored area violations may appear in counties far upwind or downwind of the local area of interest. In those cases, the distance to the nonattainment area and ability of the modeling to represent far downwind areas should be evaluated on a case-by-case basis.

The spatial resolution of the unmonitored area analysis should be consistent with the appropriate model resolution for the attainment demonstration. For example, if the attainment demonstration for ozone or PM_{2.5} is conducted at 12km grid resolution, then in most cases, the unmonitored area analysis should also be performed at the same horizontal resolution.

4.7.1 Why does the unmonitored area analysis need to use both ambient data and model output?

When performing an unmonitored area analysis, it is recommended to use interpolated spatial fields of ambient data in combination with gridded modeled outputs (i.e., fused surfaces). Ambient data can be interpolated to provide a set of spatial fields. The resultant spatial fields will provide an indication of pollutant concentrations in monitored and unmonitored areas. But interpolated ambient data cannot identify unmonitored areas with higher concentrations than those measured at monitors. The interpolated concentration between monitors will generally be the same or lower than the measured concentration at the monitors (assuming that more sophisticated statistical techniques are not used). Simple interpolation techniques do not account for emissions or chemistry information that may be needed to identify high concentrations in unmonitored areas.

In addition to interpolated surfaces, gridded model output (absolute) concentrations (from a chemical transport model) can be used to examine unmonitored area concentrations. The model provides an hourly concentration output for every grid cell. The concentrations can be analyzed to determine unmonitored areas where the model predicts high values. But the absolute predictions from the model may not be entirely accurate (they may be biased high or low). But unlike the interpolated ambient data, the model explicitly accounts for emissions, chemistry, and meteorological processes over the entire domain.

Interpolated ambient data and absolute model outputs both have strengths and weaknesses. We can take advantage of the strengths of each dataset by combining the two types of data. Interpolated spatial fields of ambient data provide a strong basis for estimating accurate pollutant concentrations at and near monitor locations. And the model outputs can be used to

adjust the interpolated spatial fields (either up or down) so that more accurate estimates can be derived in unmonitored areas.⁷⁶ A recommended way to use the modeling in the creation of fused surfaces is to adjust the ambient spatial fields using the concentration *gradients* derived from the model predictions. It is preferable to assume that the model is accurately predicting areas of generally high or low ozone or PM, rather than to assume that the absolute predictions from the model are correct. For example, in unmonitored locations where the model predicts relatively high ozone or PM concentrations, the spatial fields can be adjusted upward. In unmonitored locations where the model predicts relatively low ozone or PM concentrations, the spatial fields can be adjusted downward. In this way, it may be possible to predict unmonitored locations that may be likely to record high concentrations (were a monitor located there). We refer to this combination of interpolated spatial fields and modeled output as “gradient adjusted spatial fields.”

4.7.2 Implementation of Gradient Adjusted Spatial Fields

A recommended methodology for developing gradient adjusted spatial fields is to first create base year fields. Future year estimates can then be created by applying gridded RRFs to the base year gradient adjusted spatial fields. The basic steps are as follows:

- 1) Interpolate base year ambient data to create a set of spatial fields.
- 2) Adjust the spatial fields using gridded model-based spatial gradients (base year values).
- 3) Apply gridded model-based RRFs to the gradient adjusted spatial fields.
- 4) Determine if any unmonitored areas are predicted to exceed the NAAQS in the future.

EPA’s [SMAT](#) will spatially interpolate data, adjust spatial fields based on model output gradients, and multiply the fields by model calculated RRFs (steps 1-3 above) (U.S. EPA, 2018), (ABT, 2014). Air agencies can use the EPA-provided software or may wish to develop alternative techniques that may be appropriate for their area, situation, and/or purpose. Air Agencies should consult with the appropriate EPA Regional office to determine if and how an unmonitored area analysis should be conducted.

Step 1

The first step in developing an unmonitored area analysis is to interpolate ambient data. Ideally, design values should be interpolated. Either the 5-year weighted average design values

⁷⁶ The accuracy of interpolated fields can be evaluated by removing data from monitors (either in groups or one at a time) to see how well the interpolation scheme estimates known concentrations at ambient monitoring sites. This is known as a cross-validation.

that are used in the monitor based modeled attainment test or a single design value period can be used in the development of ambient spatial fields. Care should be taken so that the interpolated fields are not unduly influenced by monitoring sites that do not have complete valid data. Since the design values can vary significantly from year to year, it is important to use a consistent set of data.

We are not recommending a single interpolation technique. EPA's SMAT uses the Voronoi Neighbor Averaging (VNA) interpolation technique. Past analyses have used a Kriging interpolation technique (U.S.EPA, 2004).

For ozone analyses, a single spatial field of ozone values is needed. But for the PM_{2.5} NAAQS, the EPA recommends creating interpolated spatial fields for PM_{2.5} (FRM) and for each component species of PM_{2.5}. For the annual PM_{2.5} NAAQS, a set of quarterly average spatial fields can be created. The four quarters are averaged to get an annual average set of fields.

For the 24-hour PM_{2.5} standard, a spatial field can be created using the high end of the distribution of 24-hour PM_{2.5} concentrations. This is best represented by interpolating the measured high values from each quarter. For the PM_{2.5} component species, we recommend interpolating the high PM_{2.5} days in each quarter. This can be based on the highest monitored days in each quarter.

Step 2

The second step in the process involves the use of gridded model output to adjust the spatial fields derived from ambient data. SMAT uses the eVNA technique, where the VNA interpolation is "enhanced" by adjusting the interpolated values based on the modeled ozone or PM (or PM species) gradient. See the SMAT user's guide for more details (U.S. EPA, 2018), (Abt, 2014). Other "model adjusted" spatial fields techniques include Hierarchical-Bayesian (McMillan, 2010) and "Downscaler" (Berrocal, 2010a and 2010b).

A specific metric is needed to determine the model predicted gradient in concentrations for each of the NAAQS. For ozone, a logical metric is the 4th highest ozone prediction in each grid cell.⁷⁷ For the annual PM_{2.5} NAAQS, the model predicted quarterly mean concentrations for PM_{2.5} and PM_{2.5} species can be used to adjust the ambient spatial fields. For the 24-hour PM_{2.5} NAAQS, the gradient adjusted fields can be derived from the high end of the distribution of

⁷⁷ The metric should approximate the measured design values at monitoring sites. Depending on the days modeled, other metrics, such as the average of the top 4 modeled days may be a better proxy for the design value.

daily averages in each quarter. This could be for the top 10% of modeled days in each quarter or for all days with 24-hour average concentration > 35 $\mu\text{g}/\text{m}^3$ (or some other relatively high value).

Step 3

The next step is to create future year spatial fields by multiplying the base year gradient adjusted spatial fields by model derived gridded RRFs. The RRFs for the unmonitored area analysis are calculated in the same way as the monitored based attainment test (except that the grid cell array is not typically used in the spatial fields based analysis). The future year concentrations are equal to the base year concentration multiplied by the RRF in each grid cell. For ozone, a single spatial field is multiplied by a single set of model derived RRFs. For $\text{PM}_{2.5}$, the RRFs for each of the species, for each quarter, are multiplied by the spatial fields for each species, for each year.

4.7.3 Using the Results of the Unmonitored Area Analysis

For ozone and/or $\text{PM}_{2.5}$ attainment demonstrations, the future year gradient adjusted spatial fields can be analyzed to determine if any grid cells are predicted to remain above the NAAQS. States should consult with their EPA Regional office to determine if an unmonitored area analysis should be conducted for a particular nonattainment area and, if so, how the analysis should be conducted and how the results should be used.

5.0 What Is the Recommended Modeling Method for Developing Air Quality Goals for Regional Haze?

This section focuses on the modeling analysis needed to set RPGs that reflect the enforceable emission limitations, compliance schedules, and other measures included in the long-term strategy of a regional haze SIP.⁷⁸ In this section, we describe the recommended modeled analysis to assess visibility conditions at the end of an implementation period (i.e., the future end-point of a multi-year planning period under the regional haze program). The visibility analysis has many similarities to the PM_{2.5} attainment tests described in sections 4.4 and 4.5. The recommended visibility analysis and the attainment tests both use monitored data to define base year air quality. They divide PM_{2.5} into major species, and component-specific relative response factors are multiplied by base year monitored values to estimate future concentrations.

Section 5.1 provides background information on the requirements of the Regional Haze Rule and explains how RPGs are used in the regional haze program once they are set. The rest of the section describes the recommended modeling analysis to evaluate future year changes in visibility impairment. This document does not address how a state should develop its long-term strategy of emissions controls for regional haze or determine the uniform rate of progress for a Class I area.

5.1 Regional Haze Rule Background

The modeling results are used to quantify the amount of progress, expressed in deciviews of visibility improvement, anticipated to be made at individual Class I areas as of the end of an implementation period. Reasonable progress goals are calculated separately for the 20% most impaired days and the 20% clearest days at each Class I area. These values are then compared to visibility conditions in the “baseline period” (2000-2004 for most areas)⁷⁹ for the same type of

⁷⁸ The main regional haze section of the guidance is related to setting reasonable progress goals. However, the guidance methods may also be applicable to other regional haze related modeling, including, but not limited to, evaluation of visibility impacts from sources and/or source sectors (including international impacts).

⁷⁹ In the context of attainment demonstrations for ozone and PM_{2.5}, the term “baseline period” is commonly used to refer to the base period used for modeling. Because the Regional Haze Rule defines “baseline period” specifically as 2000-2004, this section uses “baseline” and “baseline period” only when referring to 2000-2004. The term “base period” is used when referring to a more recent 5-year period used in the modeling-based projection of RPGs.

days (i.e., most impaired and clearest) to verify that the SIP provides for an improvement in visibility on poor visibility days and allows no degradation in visibility on good visibility days. The RPGs for the most impaired days are also plotted against the uniform rate of progress that would be needed at individual Class I areas to achieve natural visibility conditions in 2064, starting at baseline visibility conditions for 2000-2004. The results of this comparison inform whether the SIP must contain an additional component demonstrating that no additional control measures are necessary to make reasonable progress.

Reasonable progress goals are a regulatory construction promulgated to implement the statutory requirements for visibility protection. Section 169A(a)(1) of the Clean Air Act states, “Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution.” This section later directs EPA to promulgate regulations to assure reasonable progress towards meeting this goal. Section 169B calls for EPA to “carry out the Administrator's regulatory responsibilities under [Section 169A], including criteria for measuring ‘reasonable progress’ toward the national goal.”

In response to these mandates, EPA promulgated the Regional Haze Rule on July 1, 1999.⁸⁰ The rule was revised on January 10, 2017.⁸¹ The regulations promulgated at 40 CFR 51.308(f) contain the relevant requirements for SIPs for the second and subsequent implementation periods, which are the SIPs that this guidance document addresses. Under section 51.308(f)(2), every state must determine the emission limitations, compliance schedules, and other measures that are necessary to make reasonable progress at Class I areas in the state and other Class I areas that may be affected by sources in the state. The collection of these measures is referred to as the long-term strategy. Under section 51.308(f)(3), a state in which a mandatory Class I Federal area is located must establish RPGs, one each for the 20% most impaired days and the 20% clearest days (expressed in deciviews) for each such area. These RPGs reflect the visibility conditions that are projected to be achieved by the end of the applicable implementation period as a result of its own and other states’ long-term strategies, as well as the implementation of other requirements of the CAA. They are interim goals that represent the incremental visibility improvement achieved in each implementation period toward Congress’s goal of eliminating visibility impairment from manmade emissions sources. The long-term strategy and the RPGs are developed in consultation with other affected air agencies and

⁸⁰ See 64 FR 35714.

⁸¹ See 82 FR 3078.

Federal Land Managers.⁸²

The Regional Haze Rule contains the following requirements that involve the RPGs once they have been set.

The reasonable progress goals (RPGs) must provide for an improvement in visibility for the 20% most anthropogenically impaired days relative to baseline visibility conditions and ensure no degradation in visibility for the 20% clearest days relative to baseline visibility conditions.⁸³ As explained in the RHR, the baseline for each Class I area is the average visibility (in deciviews) for the years 2000 through 2004.⁸⁴ The visibility conditions in these years are the benchmark for both the “provide for an improvement” and “no degradation” requirements.

States are also required to determine the rate of improvement in visibility needed to reach natural conditions by 2064 for the 20% most anthropogenically impaired days, given the starting point of the 2000-2004 baseline.⁸⁵ The “glidepath,” or uniform rate of progress (URP), is the amount of visibility improvement needed to stay on a linear path from the baseline period to natural conditions. Every state must compare its RPG for the 20% most anthropogenically impaired days to the point on the glidepath corresponding to the end of the implementation period. The results of this comparison determine whether a SIP must contain a demonstration that no additional emission reductions are needed to make reasonable progress towards achieving natural visibility conditions.

This section does not address the process of calculating the glidepath or determining the measures for inclusion in the long-term strategy.⁸⁶

5.2 How is Regional Haze Measured?

Regional haze is measured by an *extinction coefficient* (b_{ext}) that represents light attenuation resulting from scattering and absorption of light from ambient PM plus scattering of light due to gas molecules in the air (i.e., Rayleigh scattering). Although b_{ext} can be estimated by several

⁸² See 40 CFR 51.308(f)(2)(ii) and 51.308(i).

⁸³ See 40 CFR 51.308(f)(3)(i).

⁸⁴ See 40 CFR 51.308(f)(1) and definitions in 51.301.

⁸⁵ See 40 CFR 51.308(f)(1).

⁸⁶ For more details on calculating the URP and regional haze policy guidance, see [draft guidance for the second implementation period](#) [note that the draft guidance document will be updated in Spring 2019].

different methodologies, the RHR requires that it be estimated using measured ambient PM. This follows since, for a given set of meteorological conditions, visibility can be improved by reducing concentrations of ambient PM. Thus, deriving b_{ext} in this manner provides a direct link between regional haze and related pollutant concentrations.

5.2.1 IMPROVE Algorithm

The IMPROVE equation or algorithm reflects empirical relationships derived between measured mass of PM components and transmissometer measurements of b_{ext} at a subset of monitoring sites in Class I areas within the IMPROVE monitoring network. The IMPROVE program revised the IMPROVE algorithm in 2006 (Hand, 2006); (Pitchford, 2007). The revised algorithm is intended to reduce biases in light extinction estimates. The revised algorithm is as follows:

$$\begin{aligned}
 b_{\text{ext}} = & 2.2 \times f_s(\text{RH}) \times [\text{Small Sulfate}] + 4.8 \times f_L(\text{RH}) \times [\text{Large Sulfate}] \\
 & + 2.4 \times f_s(\text{RH}) \times [\text{Small Nitrate}] + 5.1 \times f_L(\text{RH}) \times [\text{Large Nitrate}] \\
 & + 2.8 \times [\text{Small Organic Mass}] + 6.1 \times [\text{Large Organic Mass}] \\
 & + 10 \times [\text{Elemental Carbon}] \\
 & + 1 \times [\text{Fine Soil}] \\
 & + 1.7 \times f_{ss}(\text{RH}) \times [\text{Sea Salt}] \\
 & + 0.6 \times [\text{Coarse Mass}] \\
 & + \text{Rayleigh Scattering (site specific)} \\
 & + 0.33 \times [\text{NO}_2 \text{ (ppb)}]
 \end{aligned}
 \tag{5.1}$$

The numerical coefficients on the right hand side of the equation represent the light scattering or absorption efficiency, m^2/gm of the corresponding component of particulate matter,

$f_s(rh)$, $f_L(rh)$, $f_{ss}(rh)$ are relative humidity adjustment factors applied to the light scattering efficiency (to be described in greater detail shortly), dimensionless;

SO_4 is the mass associated with sulfates, $\mu\text{g}/\text{m}^3$;

NO_3 is the mass associated with nitrates, $\mu\text{g}/\text{m}^3$;

OC is the mass associated with organic carbon, $\mu\text{g}/\text{m}^3$;

EC is the mass associated with elemental carbon, $\mu\text{g}/\text{m}^3$;

Fine Soil is inorganic primary particulate matter (excluding primary sulfate and nitrate particles) associated with soil components with aerodynamic diameter $\leq 2.5 \mu\text{m}$, $\mu\text{g}/\text{m}^3$;

CM is coarse PM with aerodynamic diameter $> 2.5 \mu\text{m}$, but $\leq 10 \mu\text{m}$, $\mu\text{g}/\text{m}^3$;

b_{rayleigh} is light-scattering attributable to Rayleigh scattering, Mm^{-1} (i.e., inverse “mega-meters”); and

b_{ext} is the estimated extinction coefficient, Mm^{-1} .

The total sulfate, nitrate and organic mass concentrations are each split into two fractions, representing small and large size distributions of those components. The organic mass concentration is calculated as 1.8 times the measured IMPROVE organic carbon concentration, to adjust for organic mass from elements other than carbon. Terms are included for sea salt (important for coastal locations) and for absorption by NO_2 (only used where NO_2 data are available). Site-specific Rayleigh scattering is calculated based on the elevation and annual average temperature of each IMPROVE monitoring site.

The apportionment of the total concentration of sulfate compounds into the concentrations of the small and large size fractions is accomplished using the following equations:

$[\text{Large Sulfate}] = [\text{Total Sulfate}]/20 \mu\text{g}/\text{m}^3 \times [\text{Total Sulfate}]$, for $[\text{Total Sulfate}] < 20 \mu\text{g}/\text{m}^3$

$[\text{Large Sulfate}] = [\text{Total Sulfate}]$, for $[\text{Total Sulfate}] \geq 20 \mu\text{g}/\text{m}^3$

$[\text{Small Sulfate}] = [\text{Total Sulfate}] - [\text{Large Sulfate}]$

The same equations are used to apportion total nitrate and total organic mass concentrations into the small and large size fractions.

Sea salt is calculated as $1.8 \times [\text{Chloride}]$ or $1.8 \times [\text{Chlorine}]$ if the chloride measurement is below detection limits, missing or invalid. The algorithm also uses three water growth adjustment terms. They are for use with the small size distribution and the large size distribution sulfate and nitrate compounds and for sea salt ($f_s(\text{RH})$, $f_L(\text{RH})$ and $f_{ss}(\text{RH})$ respectively).

All or nearly all states used the revised algorithm in their SIPs for the first implementation period and the IMPROVE program has stopped reporting visibility data using the original

IMPROVE equation. Therefore, we now recommend using the revised IMPROVE equation for all reasonable progress related modeling calculations.

5.2.2 Deciview Haze Index

The RHR requires that reasonable progress is to be measured in terms of changes in a *deciview haze index* or simply “deciviews” (dv). Deciviews are defined as the natural logarithm of the ratio of the extinction coefficient to Rayleigh scattering (Pitchford and Malm, 1994).

$$\text{Deciview} = 10 \ln(b_{\text{ext}}/10) \quad [5.2]$$

Where the units of b_{ext} and light scattering due to Rayleigh scattering⁸⁷ (i.e., the “10” in the denominator of the logarithmic expression) are both expressed in Mm^{-1} .

A *change* in deciviews, which is how progress is tracked, is given by Equation (5.3). A one deciview change is equivalent to ~10% change in b_{ext} .

$$\Delta dv = dv_{\text{future}} - dv_{\text{base}} \quad [5.3]$$

A negative number indicates a reduction in deciviews, which is an improvement in visibility.

5.2.3 Estimating Mass Associated with Components of Particulate Matter

All Class I areas either have on-site speciated $\text{PM}_{2.5}$ measurements or have been assigned a representative IMPROVE monitoring site with measurements.⁸⁸ Therefore, it is generally not necessary to interpolate measured $\text{PM}_{2.5}$ species data to a site. The existing IMPROVE database of $\text{PM}_{2.5}$ measurements should be adequate to provide data for all Class I areas.⁸⁹

FRM data is not used in the regional haze analysis and it is not necessary for the sum of species

⁸⁷ Even though the “revised” IMPROVE equation uses a site-specific Rayleigh scattering value, the denominator in the deciview equation should always be 10. In this way, the deciview calculation will be consistent across all Class I areas. When the site-specific Rayleigh scattering is less than 10 (at high elevation sites), the deciview value can be negative (on very clean days), but this should not be considered a problem.

⁸⁸ See U.S. EPA 2003b, Appendix A, Table A-2.

⁸⁹ There are some IMPROVE sites that do not have enough complete data to provide baseline condition information for the 2000-2004 period. Data substitution is addressed in 40 CFR 51.308(f)(1)(i) and also discussed in (U.S. EPA 2003b).

components to equal gravimetric measurements obtained with a Federal Reference or equivalent method for measuring PM_{2.5}. Therefore, for regional haze calculations, it is not necessary to use the speciated data adjustment procedures introduced in section 4.4 (the “SANDWICH” adjustments).

Hand (2006) has developed a set of default assumptions for mass associated with each of the components of PM for Equation (5.1). These are presented in Table 5.1. The components in Table 5.1 are similar to those used in the modeled attainment demonstrations for the PM_{2.5} NAAQS. Notice, however, that sulfate and nitrate mass are assumed to be fully neutralized (therefore, ammonium is not needed as a separate component); organic carbon is assumed to be equal to 1.8 times **measured** OC mass; there is no water component; and there is a term for coarse PM.

Table 5.1. Default Assumptions Used to Derive Aerosol Species Concentrations from IMPROVE Data for Estimating Extinction Coefficients

(1) Species	(2) Formula	(3) Assumptions
Sulfate	1.375 *measured SO ₄	Sulfate is assumed to be fully neutralized (ammonium sulfate)
Nitrate	1.29 * measured nitrate	Denuder efficiency is ~100% & all nitrate is from ammonium nitrate
EC	high + low temperature EC	All high temperature carbon is elemental
OC	1.8 * organic carbon	Average organic molecule is 56% carbon
Fine Soil	2.2*Al + 2.49*Si + 1.63*Ca + 2.42*Fe + 1.94*Ti	(Soil K)=0.6(Fe), FeO & Fe ₂ O ₃ are equally abundant, a factor of 1.16 is used for MgO, Na ₂ O, H ₂ O & CO ₃
Sea Salt	1.8*Cl ⁻	Sea salt is 55% chloride ion by weight

PM_{2.5}		-Measured gravimetrically -Represents dry ambient fine aerosol mass
CM (coarse mass)	(PM₁₀) - (PM_{2.5})	Consists only of insoluble soil particles

Throughout this section we make every attempt to be consistent (aside from the use of the revised IMPROVE algorithm) with corresponding parts of the “Guidance for Tracking Progress under the Regional Haze Program” (hereafter referred to as the “Tracking Guidance”) (U.S. EPA, 2003b). It will be easier to interpret the modeling results and compare them to measured values if the modeled future year data are calculated in a manner similar to the ambient data.

5.2.4 Normalizing Trends in Regional Haze - f(rh) Factors

It is clear from equation 5.1 that relative humidity can have a substantial effect on estimated extinction coefficients, as well as the relative importance of changes in different components of PM on trends in regional haze. Because of the importance of relative humidity as a determinant of regional haze, it is necessary to normalize any apparent trend in the estimated extinction coefficient for differences in relative humidity. This enables an assessment of how much an emissions control strategy will reduce regional haze, without the confounding effects of different relative humidity levels during the base and future periods.

There are two possible approaches to normalize trends in visibility for changes in relative humidity between the past and future. The first is to assume that the same day-specific values for relative humidity which were observed in the base period calculations will occur in future years. Thus, one would use the relative humidity observations made on a specific day together with measured components of particulate matter on that day to compute the day-specific visibility extinction coefficient on that day in the future. However, the approach could lead to misleading conclusions if humidity observations were missing for some days or if the humidity observations are atypical in some way. Further, if an air agency wanted to perform visibility calculations in a number of Class I areas, it would need to obtain hourly relative humidity data for each area.

The second approach is to review relative humidity data over a long period of record to derive climatological estimates for relative humidity adjustment factors. These climatological estimates can then be used in Equation 5.1 to estimate visibility extinction coefficients. These

estimates are more likely to reflect “typical” relative humidity at different times of year and, thus, expected future visibility extinction.

There are obvious advantages in using climatological $f(rh)$ data for tracking progress of measured data. The measured relative humidity on the 20% most impaired days in a historical period will be different than the measured relative humidity in a future period. Therefore, the only way to normalize for relative humidity between the base and future years in the context of measured data is to use a single climatological value. However, in the context of modeling, there is a choice between climatological data or modeled (or measured) relative humidity data from a meteorological model. Since the modeled meteorological data is held constant when predicting future year air quality, the modeled relative humidity values would also be constant. This would be one way to normalize the data. But since the Tracking Guidance recommends tracking visibility using climatological $f(rh)$ values, it will be easier to interpret the modeling results and compare them to future measured values if the data are calculated in a similar manner. Therefore, we recommend using climatological $f(rh)$ values to calculate base period and future visibility. Appendix A (Table A-1) from the Tracking Guidance displays the relationship between relative humidity and $f(rh)$ values. The $f(rh)$ values were calculated from relative humidity data reported by Tang (1996). The $f(rh)$ values are 1.00 up to 36% relative humidity and grow to a maximum value of 7.40 at a relative humidity of 95%.⁹⁰ These values were calculated using 10 years of meteorological data.

For calculations with the revised IMPROVE equation, three separate $f(rh)$ curves are needed (small, large, and sea salt). These can be found in (Hand, 2006). The monthly $f(rh)$ values for both the old and revised IMPROVE equations have been incorporated into pre-calculated daily extinction and deciview data that can be found on the [IMPROVE website](#). The use of pre-calculated $f(rh)$ and visibility data makes it easier for air agencies and regional organizations to calculate visibility changes and will also provide for more consistency.

5.3 How Do I Apply a Model to Calculate Changes in Visibility?

The purpose of a regional haze modeling assessment is to project future visibility conditions representing the RPGs, which are used to satisfy the requirements described in section 5.1. In

⁹⁰For the regional haze calculations, the $f(rh)$ factors have been capped at the $f(rh)$ value associated with 95% relative humidity. Relative humidity value above 95% use the same value.

the procedures below, the observed base period visibility data should be linked to the base modeling year. Similar to the ozone and PM_{2.5} attainment tests, the 5-year ambient data period should be centered about the base modeling year. For example, for a base modeling year of 2014, the ambient IMPROVE data should be from the 2012-2016 period.⁹¹ However, unlike the ozone and PM_{2.5} attainment tests, the calculation is a 5-year mean where each year counts equally (unlike the 5-year weighted average values for the ozone and PM_{2.5} attainment test). This is consistent with the regional haze rule ambient data calculations for the 20% most impaired days and 20% clearest days. The analysis we recommend has 6 steps.

- 1) For each Class I area, estimate anthropogenic impairment on each day using observed speciated PM_{2.5} and PM₁₀ data plus climatological $f(rh)$ and Rayleigh scattering data for each of the 5 years comprising the base period (this estimation step is not addressed in this document), and rank the days on this indicator. This ranking will determine the 20% most anthropogenically impaired days and the 20% clearest days.
- 2) For each of the 5 years comprising the base period, calculate the mean deciviews for the 20% most anthropogenically impaired days and 20% clearest days. For each Class I area, calculate the 5-year mean deciviews for most impaired and clearest days from the 5 year-specific values.
- 3) Use an air quality model to simulate base period emissions and future emissions. Use the resulting information to develop RRFs for each component of PM identified on the right-hand side of Equation (5.1).
- 4) Multiply the RRFs by the measured species concentration data during the base period (for the measured 20% most impaired days and 20% clearest days). This results in daily future year species concentrations data.
- 5) Using the results in Step 4 and the IMPROVE algorithm (equation 5.1), calculate the future daily extinction coefficients for the 20% most impaired days and 20% clearest days in each of the 5 base years.
- 6) Calculate daily deciview values (from total daily extinction) and then compute the future average mean deciviews for the 20% most impaired days and 20% clearest days for each

⁹¹ The *baseline period* for the regional haze program continues to be 2000-2004, and the uniform rate of progress is calculated using that historical data. However, the modeled reasonable progress visibility projections should use ambient data from a 5-year *base period* that corresponds to the modeled base year meteorological and emissions data. In addition, ambient data trends for the 5-year base period should be examined to make sure the base modeling year emissions are representative of the period. In some cases, an alternative base ambient data period may be more representative of a base modeling year.

year. Average the 5 years together to get the final future year mean deciview values for the 20% most impaired days and 20% clearest days.

We describe each of these steps more fully below. The methodology follows the same basic procedures outlined in the Tracking Guidance, however, based on the revised regional haze rule, a draft methodology (for steps 1 and 2) is available for calculating the most anthropogenically impaired and clearest days (U.S. EPA, 2016d).⁹² We conclude this subsection with an example illustrating the recommended modeled uniform rate of progress analysis.

Step 1. Using monitored data, rank base period visibility for each day with PM₁₀, PM_{2.5} and speciated PM_{2.5} measurements within a Class I area.

Ranking should be performed separately for each of the 5 years comprising the base period.⁹³ The deciview (dv) should serve as the basis for ranking. Day-specific observations for mass associated with SO₄, NO₃, OC, EC, soil, and CM, as defined in Table 5.1, should be used to calculate b_{ext} for each day. The appropriate month- and area-specific climatological relative humidity adjustment factor(s) ($f(rh)$) should be used. Total b_{ext} for all components should be converted to deciviews for each day to get a daily deciview value.

Step 2. Calculate the average base period deciviews for the 20% most anthropogenically impaired days and 20% clearest days.

For each of the 5 years in the base period, order all days considered in Step 1 from worst (highest deciview value) to best (lowest deciview value) visibility. For each year, note the 20% most impaired days and 20% clearest days. Calculate the arithmetic mean deciview value for the identified 20% most impaired days and 20% clearest days in each year. Average the resulting 5 yearly mean deciview values reflecting the most impaired days. This represents the value subject to improvement requirement (i.e., the value must decrease). Average the 5-yearly mean deciview values reflecting mean visibility on the clearest days. This is the value subject to the requirement of no degradation (i.e., the value cannot increase).

⁹² A final recommendation is expected in Fall 2018.

⁹³ Pre-calculated and ranked anthropogenic impairment, extinction, and deciview calculations for all Class I areas is available on the [IMPROVE website](#). This data can be used to satisfy steps 1 and 2. States may also choose to use an alternative methodology to calculate anthropogenic impairment for Class I areas, which may differ from the default EPA recommended methodology. States should consult with their EPA Regional office to discuss appropriate methodologies for alternative impairment calculations.

Step 3. Estimate RRFs for each component of PM_{2.5} and for CM.

The RRFs should be determined using results from air quality modeling of base year and future year emissions. These model simulations should be performed for a large number of days (presumably at least a full year; see section 2.3.1 for more details). The (temporal) arithmetic mean concentration for each PM_{2.5} component (and coarse mass) computed near the Class I monitoring site from the future year modeling is divided by the corresponding arithmetic mean concentration for each component from the base year modeling. The resulting ratios are the component-specific RRF's. A separate set of RRF values are calculated for the 20% most impaired days and 20% clearest days identified in step 2. The RRFs are calculated using the model outputs corresponding to the *monitored* 20% most impaired days and 20% clearest days at each Class I area. This will likely be a different set of days at each monitor.

Step 4. Using the RRFs and ambient data, calculate future year daily concentration data for the clearest and most impaired days.

Multiply the RRFs derived in Step 3 by measured daily concentration data for each component of PM_{2.5} and CM to get future daily estimates of species concentrations for PM_{2.5} components and CM on the 20% most impaired days and 20% clearest days. These multiplications produce future concentration estimates for SO₄, NO₃, OC, EC, soil, sea salt, and CM for each of the previously selected 20% most impaired days and 20% clearest days. This calculation is performed for the 5-year period using an RRF for each PM component (a separate set of RRFs for the 20% most impaired days and 20% clearest days).

Step 5. Use the information developed in Step 4 to compute future year daily b_{ext} values for the 20% most impaired days and 20% clearest days.

Use the future year concentration data calculated in step 4 to calculate future year daily b_{ext} values for each PM component for each of the 20% most impaired days and 20% clearest days for the 5-year period. This is accomplished by applying the revised IMPROVE visibility algorithm (equation 5.1).

Step 6. Use the daily total b_{ext} values from step 5 to calculate future mean deciview values for the 20% most impaired days and 20% clearest days .

The total daily b_{ext} for each day is converted to deciviews. This gives a future year daily deciview value for each of the 20% most impaired days and 20% clearest days.

Next, compute the arithmetic mean future deciview value for the 20% most anthropogenically

impaired days and 20% clearest days for each year. This leads to five future estimated mean deciview values for the worst and five future estimated mean deciview values for the best visibility days. Compute the arithmetic mean of the five mean values for deciviews on the 20% most anthropogenically impaired days, and the arithmetic mean of the five mean deciview values estimated for the 20% clearest days. The resulting 5-year average mean values for deciviews on 20% most impaired days and 20% clearest days will be compared to the base period mean deciview values calculated in step 2. If the resulting change in deciviews is a negative number (future - base), this represents an improvement in visibility. The future year visibility value for the 20% most impaired days will also be compared to the glidepath to determine if the Class I area is expected to be on, above, or below the glidepath in the future implementation period.

Example 5.1

We use example 5.1 to illustrate the modeled visibility assessment. For ease of presentation, we assume there are only 10 speciated samples for PM in each of the 5 years comprising the base period. Since sampling occurs every third day, a typical sample size is ~120 days per year. We illustrate the calculations for the first base year and then furnish information regarding mean deciviews for the other 4 base years to illustrate subsequent steps in the test.

Given:

Ten days have measured components of PM in a Class I area during the first year of a 5-year base period. Table 5.2 below shows the measurements (in $\mu\text{g}/\text{m}^3$) for each of the 10 days. Table 5.2 also shows the date of each measurement and the corresponding climatological relative humidity adjustment factor (made up for this example) for the appropriate month and area.

Table 5.2 Example observed IMPROVE data at a Class I area

Day	Date	$f_s(\text{RH})$	$f_L(\text{RH})$	$F_{SS}(\text{RH})$	Ammonium Sulfate ($\mu\text{g}/\text{m}^3$)	SO_4L ($\mu\text{g}/\text{m}^3$)	SO_4S ($\mu\text{g}/\text{m}^3$)	Ammonium Nitrate ($\mu\text{g}/\text{m}^3$)	NO_3L ($\mu\text{g}/\text{m}^3$)	NO_3S ($\mu\text{g}/\text{m}^3$)
1	1/7	3.82	2.75	3.91	2.004	0.201	1.804	1.050	0.055	0.995
2	2/24	3.29	2.46	3.49	2.290	0.262	2.028	0.453	0.010	0.442
3	4/15	3.73	2.67	3.68	2.617	0.342	2.274	1.206	0.073	1.134
4	6/20	3.82	2.73	3.82	4.580	1.049	3.531	0.528	0.014	0.514
5	7/14	4.29	3.00	4.20	2.742	0.376	2.366	0.416	0.009	0.407
6	8/10	4.35	3.04	4.27	3.512	0.617	2.896	0.161	0.001	0.160
7	8/28	4.35	3.04	4.27	2.303	0.265	2.038	0.224	0.003	0.221
8	9/18	4.59	3.17	4.44	1.759	0.155	1.604	0.409	0.008	0.400
9	10/21	4.11	2.92	4.13	1.660	0.138	1.522	0.159	0.001	0.158
10	12/14	4.21	2.97	4.20	1.975	0.195	1.780	0.854	0.036	0.818

Day	Date	Organic Mass (µg/m ³)	OM _L (µg/m ³)	OM _S (µg/m ³)	EC (µg/m ³)	Soil (µg/m ³)	Sea Salt (µg/m ³)	CM (µg/m ³)	Rayleigh Mm ⁻¹
1	1/7	3.024	0.457	2.567	0.345	0.106	0.214	1.334	12
2	2/24	1.073	0.058	1.016	0.150	0.058	0.150	2.004	12
3	4/15	2.409	0.290	2.119	0.241	0.589	0.357	5.928	12
4	6/20	2.482	0.308	2.174	0.282	0.367	0.132	3.549	12
5	7/14	3.608	0.651	2.957	0.297	0.343	0.157	6.252	12
6	8/10	1.768	0.156	1.612	0.268	0.134	0.026	1.989	12
7	8/28	1.772	0.157	1.615	0.162	0.190	0.165	2.521	12
8	9/18	1.049	0.055	0.994	0.123	0.112	0.725	3.880	12
9	10/21	1.267	0.080	1.186	0.094	0.218	0.086	1.996	12
10	12/14	1.454	0.106	1.348	0.248	0.170	0.046	2.081	12

Using the IMPROVE concentration data for the Class I area and modeled RRFs, calculate the future year extinction and deciview values for the 20% most impaired days and the 20% clearest days for the end of the implementation period addressed in the SIP.

Step 1. Using monitored data, rank base period visibility for each day with PM₁₀, PM_{2.5}, and speciated PM_{2.5} measurements within a Class I area.

First, estimate the extinction coefficient for each day that has the needed PM measurements. This is done using the information in table 5.2 with Equation (5.1). For day 1 in year 1, the current extinction coefficient is:

$$b_{\text{ext}} = (2.2 \times 3.82 \times 1.804) + (4.8 \times 2.75 \times 0.201) + (2.4 \times 3.82 \times 0.995) + (5.1 \times 2.75 \times 0.055) + (2.8 \times 2.567) + (6.1 \times 0.457) + (10 \times 0.345) + (1 \times 0.106) + (1.7 \times 3.91 \times 0.214) + (0.6 \times 1.334) + 12$$

$$b_{\text{ext}} = 55.461 \text{ Mm}^{-1}$$

Then convert extinction into deciviews:

$$dv = 10 \times \ln(55.461/10) = 17.131 \text{ dv}$$

Base year extinction coefficients and deciviews for the remaining 9 days with monitored data in year 1 are calculated in a similar manner. The days are then ranked. The day with the highest impairment is given a rank of "1." The results of these calculations are displayed in the table 5.3 below. Based on these rankings, days 4 and 5 comprise the 20% most impaired. Days 2 and 8 comprise the 20% clearest days.⁹⁴

⁹⁴ Note that this is an abbreviated example. The actual IMPROVE sampling schedule collects data every third day. Therefore, with a complete set of data, there will be ~121 samples per year at each site. Both the 20% most impaired days and 20% clearest days will be comprised of an average of ~24 sample days.

Table 5.3 Example observed IMPROVE extinction, deciviews, and rank at a Class I area

Day	Date	Rayleigh (Mm ⁻¹)	SO ₄ (Mm ⁻¹)	NO ₃ (Mm ⁻¹)	OM (Mm ⁻¹)	EC (Mm ⁻¹)	Soil (Mm ⁻¹)	CM (Mm ⁻¹)	Sea Salt (Mm ⁻¹)	B _{ext} [base period] (Mm ⁻¹)	Deciviews	Rank
1	1/7	12	17.809	9.897	9.975	3.447	0.106	0.801	1.425	55.461	17.131	5
2	2/24	12	17.777	3.621	3.195	1.500	0.058	1.203	0.891	40.244	13.924	9
3	4/15	12	23.049	11.139	7.702	2.411	0.589	3.557	2.231	62.678	18.354	3
4	6/20	12	43.421	4.905	7.967	2.815	0.367	2.129	0.857	74.460	20.077	1
5	7/14	12	27.743	4.327	12.249	2.969	0.343	3.751	1.118	64.499	18.641	2
6	8/10	12	36.711	1.687	5.467	2.680	0.134	1.194	0.187	60.061	17.928	4
7	8/28	12	23.369	2.351	5.481	1.624	0.190	1.512	1.199	47.726	15.629	7
8	9/18	12	18.556	4.546	3.117	1.234	0.112	2.328	5.473	47.366	15.553	8
9	10/21	12	15.695	1.577	3.811	0.943	0.218	1.198	0.607	36.048	12.823	10
10	12/14	12	19.267	8.817	4.418	2.475	0.170	1.248	0.328	48.723	15.836	6

Step 2. Calculate the average base year deciviews for the 20% most impaired days and 20% clearest days.

For year 1, mean deciview value for 20% most impaired days = $(20.077 + 18.641) / 2 = 19.359$ dv,

and mean deciview value for the 20% clearest days = $(12.823 + 13.924) / 2 = 13.374$ dv

Mean deciview values for the 20% most impaired and 20% clearest days for years 2-5 are provided in table 5.4.

Table 5.4 Example mean worst days visibility and best days visibility at a Class I area

Year	Mean dv _{current} 20% Most Anthropogenically Impaired Days	Mean dv _{current} 20% Clearest Days
1	19.35	13.37
2	20.32	12.54
3	19.21	11.78
4	18.93	12.32
5	18.34	12.91

The average mean base period visibility for the 20% most impaired and for the 20% clearest days is obtained by taking the arithmetic mean of these days for the 5 years. Thus, the 5-year mean of the average visibility for the 20% most impaired days is given by

$$dv_{\text{base period}} = (19.35 + 20.32 + 19.21 + 18.93 + 18.34) / 5 = \mathbf{19.23 \text{ dv}}$$

The 5-year mean of the average visibility for the 20% clearest days is

$$dv_{\text{base period}} = (13.37 + 12.54 + 11.78 + 12.32 + 12.91) / 5 = \mathbf{12.58 \text{ dv}}$$

Step 3. Apply a model to develop component specific RRF's for SO₄, NO₃, OC, EC, Soil and CM.

Tables 5.5 and 5.6 show the procedure for calculating component-specific relative response factors using an air quality model. The example shows the recommended calculation of RRFs for the 20% most impaired days in the year modeled (the abbreviated example assumes that the 20% most impaired days is represented by only 5 modeled days). The same calculation is repeated for the clearest days.

Table 5.5 Base year modeled species concentrations on the 20% most impaired days (in µg/m³)

Modeled Output	SO ₄	NO ₃	OC	EC	Soil	CM
Day 1	3.13	1.02	3.56	0.87	0.32	5.43
Day 2	5.21	3.11	4.67	1.23	0.34	4.68
Day 3	4.56	0.59	6.32	1.45	0.87	3.58
Day 4	5.51	1.67	4.56	0.54	1.07	4.67
Day 5	3.99	0.57	4.12	0.69	1.01	5.21
Mean Base Concentration	4.48	1.39	4.65	0.96	0.72	4.71

Table 5.6 Future year modeled species concentrations on 20% most anthropogenically impaired days (in $\mu\text{g}/\text{m}^3$)

Modeled Output	SO ₄	NO ₃	OC	EC	Soil	CM
Day 1	2.45	0.91	3.54	0.82	0.36	5.51
Day 2	3.98	2.98	4.62	1.15	0.37	4.81
Day 3	3.56	0.50	6.30	1.32	0.92	3.76
Day 4	4.12	1.42	4.51	0.46	1.10	4.76
Day 5	2.87	0.39	4.07	0.61	1.08	5.34
Mean Future Concentration	3.40	1.24	4.61	0.87	0.77	4.84

Table 5.7 Component specific RRFs for the 20% most impaired days

Most Impaired days RRF	SO ₄	NO ₃	OC	EC	Soil	CM
RRF (mean future/mean base)	0.758	0.891	0.992	0.912	1.061	1.026

Step 4. Multiply the relative response factors times the measured daily species concentration data during the base period to compute future daily species concentrations.

In year 1, we previously identified days 4 and 5 as those included in the 20% most impaired days (i.e., see Step 1). Similarly, days 2 and 8 are the 20% clearest days (see Table 5.3). In this step, we estimate future concentrations for components of PM_{2.5} and for CM for these two sets of days. This is done using information shown in tables presented in Steps 1 and 3 as well as the best days RRFs given in table 5.8 below:

Table 5.8 Component specific RRFs for the 20% clearest days

Clearest days RRF	SO ₄	NO ₃	OC	EC	Soil	CM
RRF (mean future/mean base)	0.780	0.752	0.956	0.768	1.022	1.043

Most Anthropogenically Impaired Days

Day 4: $[\text{SO}_4]_{\text{future}} = (\text{RRF})_{\text{SO}_4} [\text{SO}_4]_{\text{base period}} = (0.758) [4.580] = 3.472 \mu\text{g}/\text{m}^3$

$[\text{NO}_3]_{\text{future}} = (0.891) [0.528] = 0.470 \mu\text{g}/\text{m}^3$

$[\text{OC}]_{\text{future}} = (0.992) [2.482] = 2.462 \mu\text{g}/\text{m}^3$

$[\text{EC}]_{\text{future}} = (0.912) [0.282] = 0.257 \mu\text{g}/\text{m}^3$

$[\text{Soil}]_{\text{future}} = (1.061) [0.367] = 0.389 \mu\text{g}/\text{m}^3$

$[\text{CM}]_{\text{future}} = (1.026) [3.549] = 3.641 \mu\text{g}/\text{m}^3$

$[\text{Salt}]_{\text{future}} = (1.00) [0.132] = 0.132 \mu\text{g}/\text{m}^3$

Day 5: $[\text{SO}_4]_{\text{future}} = (0.758) [2.742] = 2.079 \mu\text{g}/\text{m}^3$

$[\text{NO}_3]_{\text{future}} = (0.891) [0.416] = 0.371 \mu\text{g}/\text{m}^3$

$[\text{OC}]_{\text{future}} = (0.992) [3.608] = 3.578 \mu\text{g}/\text{m}^3$

$[\text{EC}]_{\text{future}} = (0.912) [0.297] = 0.271 \mu\text{g}/\text{m}^3$

$[\text{Soil}]_{\text{future}} = (1.061) [0.343] = 0.364 \mu\text{g}/\text{m}^3$

$[\text{CM}]_{\text{future}} = (1.026) [6.252] = 6.414 \mu\text{g}/\text{m}^3$

$[\text{Salt}]_{\text{future}} = (1.00) [0.157] = 0.157 \mu\text{g}/\text{m}^3$

Clearest Days

Day 2: $[\text{SO}_4]_{\text{future}} = (0.780) [2.290] = 1.786 \mu\text{g}/\text{m}^3$

$[\text{NO}_3]_{\text{future}} = (0.752) [0.453] = 0.341 \mu\text{g}/\text{m}^3$

$[\text{OC}]_{\text{future}} = (0.956) [1.073] = 1.026 \mu\text{g}/\text{m}^3$

$[\text{EC}]_{\text{future}} = (0.768) [0.150] = 0.115 \mu\text{g}/\text{m}^3$

$[\text{Soil}]_{\text{future}} = (1.022) [0.058] = 0.059 \mu\text{g}/\text{m}^3$

$[\text{CM}]_{\text{future}} = (1.043) [2.004] = 2.090 \mu\text{g}/\text{m}^3$

$[\text{Salt}]_{\text{future}} = (1.00) [0.150] = 0.150 \mu\text{g}/\text{m}^3$

Day 8: $[\text{SO}_4]_{\text{future}} = (0.780) [1.759] = 1.372 \mu\text{g}/\text{m}^3$

$[\text{NO}_3]_{\text{future}} = (0.752) [0.409] = 0.308 \mu\text{g}/\text{m}^3$

$[\text{OC}]_{\text{future}} = (0.956) [1.049] = 1.003 \mu\text{g}/\text{m}^3$

$[\text{EC}]_{\text{future}} = (0.768) [0.123] = 0.094 \mu\text{g}/\text{m}^3$

$[\text{Soil}]_{\text{future}} = (1.022) [0.112] = 0.114 \mu\text{g}/\text{m}^3$

$[\text{CM}]_{\text{future}} = (1.043) [3.880] = 4.047 \mu\text{g}/\text{m}^3$

$[\text{Salt}]_{\text{future}} = (1.00) [0.725] = 0.725 \mu\text{g}/\text{m}^3$

Similar calculations (using the same model derived component specific RRFs) are performed for each of the most impaired days and clearest days in each of the other 4 years in the base

period.⁹⁵

Step 5. Using the results in Step 4, calculate the future year extinction coefficients for each of the 20% most impaired days and each of the 20% clearest days in each of the 5 base years.

Using future PM components obtained in Step 4, we can estimate future daily total b_{ext} .

For year 1

Most Impaired Days

Day 4: $b_{\text{ext}} = (2.2 \times 3.82 \times 2.869) + (4.8 \times 2.73 \times 0.603) + (2.4 \times 3.82 \times 0.459) + (5.1 \times 2.73 \times 0.011) + (2.8 \times 2.159) + (6.1 \times 0.303) + (10 \times 0.257) + (1 \times 0.389) + (1.7 \times 3.91 \times 0.132) + (0.6 \times 3.641) + 12 = 62.288 \text{ Mm}^{-1}$

Day 5: $b_{\text{ext}} = (2.2 \times 4.29 \times 1.863) + (4.8 \times 3.00 \times 0.216) + (2.4 \times 4.29 \times 0.364) + (5.1 \times 3.00 \times 0.007) + (2.8 \times 2.938) + (6.1 \times 0.640) + (10 \times 0.271) + (1 \times 0.364) + (1.7 \times 4.20 \times 0.157) + (0.6 \times 6.414) + 12 = 56.722 \text{ Mm}^{-1}$

Clearest Days

Day 2: $b_{\text{ext}} = (2.2 \times 3.29 \times 1.627) + (4.8 \times 2.46 \times 0.160) + (2.4 \times 3.29 \times 0.335) + (5.1 \times 2.46 \times 0.006) + (2.8 \times 0.973) + (6.1 \times 0.053) + (10 \times 0.115) + (1 \times 0.059) + (1.7 \times 3.49 \times 0.150) + (0.6 \times 2.090) + 12 = 34.786 \text{ Mm}^{-1}$

Day 8: $b_{\text{ext}} = (2.2 \times 4.59 \times 1.278) + (4.8 \times 3.17 \times 0.094) + (2.4 \times 4.59 \times 0.303) + (5.1 \times 3.17 \times 0.005) + (2.8 \times 953) + (6.1 \times 0.050) + (10 \times 0.094) + (1 \times 0.114) + (1.7 \times 4.44 \times 0.725) + (0.6 \times 4.047) + 12 = 41.682 \text{ Mm}^{-1}$

Step 6. Use the daily total b_{ext} values from step 5 to calculate future mean deciview values for the 20% most impaired days and the 20% clearest days.

Calculate daily deciview values (from total daily extinction) and then compute the future mean

⁹⁵ Unless multiple meteorological years are being modeled, the same mean RRFs (for each component) are applied to the concentrations on all of the most impaired days for each of the 5 years of data. The mean RRFs are derived from the modeled days. A separate set of RRFs are derived (in the same manner) for the clearest days.

deciviews for the 20% most impaired days and the 20% clearest days for each year. Then average the 5 years together to get the final future mean deciview value for each set of days.

For Year 1

Most Impaired Days

Day 4: $62.288 \text{ Mm}^{-1} = 10 * \ln (62.288/10) = 18.291 \text{ dv}$

Day 5: $56.722 \text{ Mm}^{-1} = 10 * \ln (56.722/10) = 17.355 \text{ dv}$

Future mean visibility on most anthropogenically impaired days = $(18.291 + 17.355) / 2 = 17.82 \text{ dv}$

Clearest Days

Day 2: $34.786 \text{ Mm}^{-1} = 10 * \ln (34.786/10) = 12.466 \text{ dv}$

Day 8: $41.682 \text{ Mm}^{-1} = 10 * \ln (41.682/10) = 14.274 \text{ dv}$

Future mean visibility on clearest days = $(12.466 + 14.274) / 2 = 13.37 \text{ dv}$

Similar calculations are performed for previously selected 20% most impaired days and the 20% clearest days in each of years 2-5. Assume these other calculations yield the following estimates for future mean dv on these sets of days.

Table 5.9 Future year mean deciviews on the 20% most impaired days and the 20% clearest days for each of the 5 years

Year	Future Mean dv on 20% Most Impaired Days	Future Mean dv on 20% Clearest Days
1	17.82	13.37
2	18.17	12.45
3	16.78	12.91
4	18.65	11.52
5	18.21	12.31

Using results in table 5.9, we see that the estimated future average mean visibility for the most impaired days is

$$\mathbf{dv}_{\text{future}} = (17.82 + 18.17 + 16.78 + 18.65 + 18.21) / 5 = \mathbf{17.92 \text{ dv}}$$

The estimated future average mean visibility for the clearest days is

$$\mathbf{dv}_{\text{future}} = (13.37 + 12.45 + 12.91 + 11.52 + 12.31) / 5 = \mathbf{12.51 \text{ dv}}$$

The most impaired days result generated in step 6 can then be compared to the point on the Class I area-specific glidepath for the end of the implementation period. The most impaired days result is also compared to the baseline most impaired days to ensure that there has been improvement relative to the baseline period. The future year clearest days result is compared to the baseline (2000-2004) clearest days to ensure that visibility on the best days is not forecast to degrade relative to the same period.

This information is used to determine the predicted improvement in visibility that will result from implementation of an emissions strategy. It cannot itself determine the necessary content of the long-term strategy. See the Regional Haze Rule and related guidance documents for more information on the reasonable progress requirements.

5.4 How Do I Select Appropriate Inputs For Developing RPGs?

In section 5.3, we described the recommended regional modeling analysis to develop RPGs and to use them to evaluate progress relative to the glidepath and the baseline period. An important part of the analysis requires using component-specific RRFs, obtained with models, to estimate future concentrations of these components and, subsequently, future visibility. In this subsection, we address more details concerning the calculation of visibility RRFs. Additionally, there are several assumptions inherent in the recommended RPG analysis; we identify these assumptions and comment on their underlying rationale. More specifically, we address seven issues:

1. How to estimate base period air quality in a Class I area without monitored data;
2. How to handle a base year without data or with a small sample size;
3. Use of the same days to estimate changes in visibility for the most anthropogenically impaired days and a different set of same days to estimate changes in visibility for the clearest days;
4. Which predictions to use to derive RRFs;

5. How many and what kind of days to use to develop RRF values;
6. RRFs when modeled species concentration are very low; and
7. Alternative RRF calculations.

Estimating baseline and base period visibility in a Class I area without monitors

There are 156 officially designated Class I areas subject to the Regional Haze Rule and 110 IMPROVE sites in or near Class I areas. Therefore, 46 Class I areas do not have co-located IMPROVE monitors. EPA's Tracking Guidance recommends using IMPROVE data from a nearby site to represent the visibility at each Class I area that does not have ambient data. Table A-2 in Appendix A of the Tracking Guidance lists the recommended monthly $f(rh)$ values⁹⁶ for each Class I area as well as the representative site for each Class area. The representative IMPROVE site data will be used to track regional haze progress for the Class I areas. Therefore, it follows that visibility improvement for tracking purposes should be predicted at the location of the IMPROVE monitor, not at the actual Class I area. For the purposes of deriving ambient data for modeling, we recommend following the same representative site assignments contained in the Tracking Guidance. In this way, the needed visibility values can be derived for each Class I area from the network of 110 IMPROVE sites.⁹⁷ Similarly, the modeling results should be extracted for the location of the representative monitor, not the actual location of the Class I area.⁹⁸

Considering a year in the base period with little or no monitored particulate matter or missing data

The Tracking Guidance recommends calculating base period visibility values for sites with at least 3 out of 5 complete years of data. It further contains recommendations for determining if a year has complete data. In general, a site should have 50% data completeness in all quarters and meet a 75% completeness criteria for the full year. There should be no periods with more than 30 consecutive days without data. The Tracking Guidance assumes that all IMPROVE sites

⁹⁶ The $f(rh)$ values in the Tracking Guidance were developed for the "original" IMPROVE algorithm and should not be used to calculate visibility using the "revised" IMPROVE algorithm.

⁹⁷ Bering Sea Wilderness (Alaska) is the only Class I area that has no IMPROVE monitor **and** no representative IMPROVE site. On-site IMPROVE or representative IMPROVE data can be found for the other 155 Class I areas.

⁹⁸ There may be other reasons to calculate visibility improvement at the actual Class I area. The SMAT provides options for calculating visibility changes at both the Class I area grid cell center and at the representative IMPROVE monitoring site. It may be informative to compare model response at the representative IMPROVE site versus the grid cell center of the Class I area. Large differences in the model response may indicate that the "representative" site may not adequately represent visibility at the Class I area or across the entire Class I area.

will have at least 3 complete years in the base period (which may or may not be true). The Tracking Guidance also contains procedures for filling in missing data.

There are several data completeness issues that may cause problems within the visibility modeling analysis. First, a site may have less than 3 years of complete data. It is possible to calculate visibility improvement based on as little as 1 year of ambient data. Additionally, the IMPROVE program has procedures to utilize substituted and/or patched data to help minimize data incompleteness. States should work with their EPA Regional office and Federal Land Managers to determine how to estimate baseline visibility for these area(s).

Another issue that is a more specific problem for modeling analyses occurs when data is missing during the meteorological time period that was modeled. It is likely that most air agencies will only be modeling a single year of meteorology and it is possible that the ambient data at one or more Class I areas is incomplete during that year. Without ambient data, it is impossible to identify the 20% most anthropogenically impaired days and 20% clearest days, which are used to calculate modeled RRFs.

Again, if this occurs, states should work with their Regional office and Federal Land Managers to determine the best way to calculate visibility on these days. Potential options are to utilize substituted and/or patched data, data from another nearby IMPROVE site, nearby data from a different ambient data network, or interpolate ambient data to the site.

Using a constant sample of days to estimate base period and future visibility

For a typical Class I area, there will be about 120 days per year having measurements needed to estimate $(dv)_{\text{base period}}$ with Equation (5.1). Thus, there should be about 24 most anthropogenically impaired and 24 clearest days for each of the 5 years in the base period. It is conceivable that the identity of these days could change if emissions were altered to reflect net effects of controls and growth. The recommended test described in section 4.8 assumes that the identity of the most impaired and clearest days remains unchanged. This is done primarily to avoid having to perform iterative analyses to identify future most impaired and clearest visibility days and to keep the test relatively simple and more readily understood. This assumption could cause improvement in visibility to be overestimated for the most anthropogenically impaired days and could also cause the test to overestimate the difficulty in preventing deterioration of visibility on the clearest days. However, for the reasons described below, we do not believe the effects of this assumption are substantial.

It is unlikely that there would be any wholesale change in the identity of most anthropogenically impaired or clearest days with future versus base year emissions. Analyses performed by Meyer, et al. (1997) have shown that the predicted ranked severity of high ozone days is largely unaffected by simulated controls and growth (i.e., highest days tend to remain the highest days after the effects of growth and controls are simulated). There is no reason to expect a different outcome for other secondary pollutants. If there are differences, we would expect these to occur near the borderline between the most impaired days and more moderate days.

Because the visibility analysis relies on *mean* visibility values on 20 or more most impaired visibility days and most of these days are unlikely to change, we would expect little difference in the outcome of the analysis. Further, because of the shape of the distribution of daily extinction coefficients, the mean of the most impaired days is often more heavily influenced by the very most impaired days rather than those on the borderline between 20% most impaired and more moderate light extinction. There could be differences in some of the clearest visibility days corresponding with pre- and post-control emissions. However, because the differences in concentrations of particulate matter on such days are likely to be relatively low, differences in the computed mean visibility for clearest days are likely to be small. It should be noted that any resulting difference in the projection of RPGs for clearest days would likely be in the direction of it being more difficult to pass the no degradation test compared to the baseline 2000-2004 period, in that some of the future days selected may be higher deciview-valued than they ought to be. If our recommended procedure leads to suspected problems in the outcome of a test, an air agency may wish to perform a more rigorous version of the analysis (in which the identity of pre-control and post-control days changes) as part of additional or supplemental analyses to support the RPG.

Selecting predictions to use in deriving RRF

RRFs should be developed for each Class I area. When a Class I area contains a monitoring site, the RRF estimates should be derived using predictions which are made “near” that site. For each day, daily average surface predictions of each component of PM made near a monitor should be estimated. Similar to the annual PM_{2.5} NAAQS attainment test, nearby grid cells should be averaged. These nearby estimates should be spatially averaged to estimate a spatially representative daily concentration. For 12 km or finer resolution, we recommend averaging the modeled concentrations for a 3 x 3 array of grid cells surrounding the monitor. Note that for cells larger than 12 km on a side, no spatial averaging is necessary—states should just use the

prediction in the cell containing the monitor. Spatially representative daily concentrations obtained for each modeled day with monitored data should then be temporally averaged. This final average should be used to compute the RRF. Thus, component-specific RRF values for a Class I area with a monitor are the ratio of the temporally averaged spatial mean of nearby concentrations predicted with future emissions to that predicted with base year emissions.

Selecting days to derive RRF values

It may often happen that a planning organization or a group of states decides to model the visibility impacts of a strategy for numerous Class I areas simultaneously. As we note in section 2.3.1, this may make it advisable to simulate (at least) a full year so that RRF values for each Class I area are based on a substantial number of observed best and worst days. For the most impaired days in the chosen year, the RRF for a component of PM should be estimated as the ratio of its modeled arithmetic mean predicted value on the 20% most impaired days with future emissions to that with base year emissions. Thus, in most cases, the RRF should reflect values averaged over ~ 24 most impaired days in that year. The same procedure is followed to derive RRFs over the ~24 clearest days in the year.

Since meteorological conditions and/or emissions may be markedly different on best visibility versus worst visibility days, we recommend calculation of a separate set of RRF values for the 20% clearest days. As with most impaired days, the preferred approach is to model an entire year and select an RRF value for concentrations averaged over the 20% clearest days for each Class I area. The RRF values are the ratios of the future to base year modeled averages. The appropriate RRF values should then be used in concert with each observed best day to estimate future concentrations for each component on each identified clearest day.

RRFs when modeled species concentrations are very low

In most cases, the RRFs derived for visibility components are either less than 1.0 or slightly more than 1.0. However, large RRFs (much greater than 1.0) can occur when the mean modeled concentration of a PM component on the 20% most impaired or clearest days is very small and the concentration of that component increases in the future year case. This most often occurs with the nitrate component. On both the 20% most impaired days and 20% clearest days, the modeled nitrate concentrations at Class I areas can be very small (i.e., < 0.01 $\mu\text{g}/\text{m}^3$). These low modeled concentrations can sometimes increase in future year scenarios by orders of magnitude. This occurs most often in ammonia limited areas when sulfate concentrations are reduced in the future (due to SO_2 emissions reductions) causing nitrate

increases due to an increase in available ammonia. Large RRFs should be closely examined to identify the cause of the issue. In many cases, large RRFs are caused by poor model performance (i.e., underpredicted base case nitrate concentrations) or instability in one or more model components (i.e., the nitrate partitioning model). One solution is to cap the RRF at 1.0 or close to 1 in cases where nitrate (or any other PM_{2.5} component) increases in the future by an unrealistic amount due to very low modeled concentrations. Any adjustments to the default calculations should be documented and discussed with the appropriate EPA Regional office and the Federal Land Managers.

Alternative RRF calculations

The default analysis is relatively simple in that a single mean RRF is calculated for each PM component (separate RRFs on most impaired days and clearest days). A series of tests with more complicated methods has shown that: 1) the difference between various versions of the test are usually small and 2) each of the alternative tests has limitations in its applicability (Environ, 2005). Possible variations include the use of day specific RRFs, season (or quarter) specific RRFs, or climatologically based RRFs. In some cases, these more complicated techniques may provide different answers, but sometimes not. There are specific limitations with each of these alternatives noted in the indicated reference. We have chosen to keep the single mean RRF test as the default recommendation. States are encouraged to explore other methods for estimating RRFs if it is thought that the default recommendation is too simplistic to accurately capture the change in future visibility at any particular Class I area. The SIP analysis to develop RPGs should use the most appropriate method of projecting future concentrations for the characteristics of each Class I area.⁹⁹ Alternative methods should be discussed in the modeling protocol and discussed with the appropriate EPA Regional office and Federal Land Managers.

⁹⁹ In particular, issues may arise when dealing with visibility contributions from fires, coarse mass and fine soil (from wind-blown dust), and international transport (and possibly other issues). Each of these issues should be addressed in the modeling protocol and solutions should be discussed with the appropriate EPA Regional office(s) and Federal Land Managers on a case-by-case basis.

6.0 How Can Additional Analyses Be Used to Support an Ozone or PM_{2.5} Attainment Demonstration?

By definition, models are simplistic approximations of complex phenomena. The modeling analyses used to assess whether emission reduction measures will bring an individual area into attainment for the NAAQS contain many elements that are uncertain (e.g., emission projections, meteorological inputs, science formulations, etc.). These uncertain aspects of the analyses prevent definitive assessments of future attainment status. The confidence in the representativeness of the quantitative results from a modeled attainment test should be a function of the degree to which the uncertainties in the analysis were minimized. In general, by following the recommendations contained within this guidance document, EPA hopes that the attainment demonstrations will mitigate the uncertainty as much as possible given the current state of modeling inputs, procedures, and science. However, while air quality models represent the best tools for integrating emissions and meteorological information with atmospheric chemistry, and no single additional analysis can match the expected reliability of these models' results, EPA believes that all attainment demonstrations will be strengthened by additional analyses that can supplement the modeling to enhance the assessment of whether the planned emissions reductions are likely to result in attainment.

Supplemental evidence should accompany all model attainment demonstrations. Generally, those modeling analyses that show that attainment will be reached in the future with some margin of safety will need more limited supporting material. For other attainment cases in which the projected future design value is closer to the NAAQS, more rigorous supporting analyses should be completed. There may be some areas for which the supplemental evidence is persuasive enough to support a conclusion that the area can expect to achieve timely attainment despite failing the modeled attainment test, and other areas for which the modeled attainment test demonstrates attainment, but the supplemental evidence casts significant doubt on that result. This section of the guidance will discuss some specific information and additional analyses that can be used to supplement the model projections. Of particular interest are analyses that help determine whether the modeling-based projections are likely to provide a prediction of the *air quality improvement* that is likely to occur by the attainment date. Air agencies should review these supplemental analyses, in combination with the modeling analysis, in a "weight of evidence" assessment of whether each area is likely to achieve timely attainment. Again, it should be noted that no single supplemental analysis can serve as an adequate substitute for the air quality model. However, in aggregate, supplemental

analyses may provide information which may provide further support for the outcome of the modeled test or may indicate a different outcome than the modeled test.

In considering the use of supplemental analyses, an important factor is the time (number of years) until the attainment date. In general, modeling and related analyses are the most useful corroborative analyses for areas with attainment dates which are more than several years in the future. In contrast, ambient data and emissions trends become more important (and hence model results become less important) the closer in time the area is to its attainment date. For example, if an area is only 1 or 2 years away from its attainment date, ambient data is in most cases the best predictor of likely air quality levels in the near future. However, this may not be true if there are large emissions reductions that are expected to occur in the near-term period. In that case, modeling is needed to estimate additional ozone and/or PM reductions that are likely to occur due to the emissions controls in the short term. Similarly, if the attainment date is 5 or 10 years or more in the future, appropriate modeling will likely be the most reliable indicator of future year ozone or PM levels. Emission changes over a relatively long period are likely to overwhelm the influence of ambient data trends and meteorological variability, making ambient data and emissions trends analyses relatively less important.

6.1 What Types of Additional Analyses Should Be Completed as Part of an Ozone or PM_{2.5} Attainment Demonstration?

There are three basic types of analyses that are recommended to supplement the primary modeling analysis. They are:

- 1) Additional modeling analyses;
- 2) Analyses of trends in ambient air quality and emissions;
- 3) Additional emissions controls/reductions.

Note that air agencies are encouraged to consult with their EPA Regional office (and Federal Land Managers, when appropriate) in advance of initiating supplemental analyses to determine which additional analyses may be most appropriate for their particular area.

6.1.1 Modeling Analyses

The relative attainment tests described in sections 4.2, 4.4, and 4.5 are the primary modeling tools used in an attainment demonstration. The application of a chemical transport grid model on a regional or local scale is the best tool available to judge the impacts of changes in future year emissions on concentrations. In addition to this “primary” modeling analysis, there are various other models, model applications, and tools that can be used to supplement the results of the modeled attainment test. These include, but are not limited to:

- Available regional or national scale modeling applications that are suitable¹⁰⁰ for the local area, for example, modeling in support of EPA rulemakings or regional, multi-jurisdictional organization modeling that may be available for the appropriate future year of interest. Modeling analyses may be available that used different models and/or inputs.
- Use of other appropriate local modeling that includes the nonattainment area of interest. This may include applications using alternative models and/or inputs or research-oriented analyses.
- Use of photochemical source apportionment, DDM, and/or process analysis modeling tools to help explain why attainment is (or is not) demonstrated.
- Use of multiple air quality models / model input data sets (e.g., multiple meteorological data sets, alternative chemical mechanisms or emissions inventories, etc.). Multiple model configurations can be used to estimate sensitivity and uncertainty of future year design value predictions.
 - For results to be most relevant to the way we recommend models be applied in attainment demonstrations, it is preferable that such procedures focus on the sensitivity of estimated RRFs and resulting projected design values to the variations in inputs and/or model formulations.
- Application of the attainment test with alternative procedures compared to the default recommendations in sections 4.2, 4.4, and 4.5 of this guidance. Any alternate approaches

¹⁰⁰ The resolution, emissions, meteorology, and other model inputs should be evaluated for applicability to the local nonattainment area. Additionally, model performance for the local nonattainment area should be examined before determining whether the regional model results are suitable for use in the local attainment demonstration.

should be accompanied with a technical justification to explain why the approach is appropriate for the area in question and should be discussed with the appropriate EPA Regional office.

- Alternative RRF calculations using non-default assumptions or more detailed temporal and spatial analysis of RRFs at one or more monitoring locations. If a sound technical argument can be made for why atypically high RRFs at any particular location are not reasonable, then these types of supplemental analyses would suggest that attainment is more likely to be achieved than the default modeling analysis alone would indicate.
- Alternate base year design values that may differ from the 5-year weighted average value. Alternative values could include different methodologies for determining base year design values or removal of potential exceptional events data (see section 4.1.1).
- Use of dispersion models to address primary PM_{2.5} contributions to PM_{2.5} concentrations. In areas with large spatial gradients of primary PM_{2.5}, dispersion models are best suited to characterizing the change in primary PM_{2.5} in the future. A local area analysis may be useful as a supplemental analysis (in either monitored or unmonitored areas, as appropriate) for areas that at least partially rely on local primary PM controls to reach attainment and did not otherwise perform and submit a local area analysis of part of the attainment demonstration.

The EPA has determined that the best approach to using models to demonstrate attainment of the NAAQS is to use a model in a relative mode. However, some types of “absolute” model results may be used to assess general progress towards attainment from the baseline inventory to the projected future inventory.¹⁰¹ Example metrics include:

- Percent change in total amount of ozone or PM_{2.5} >= NAAQS¹⁰² within the nonattainment area
- Percent change in number of grid cells >= NAAQS within the nonattainment area
- Percent change in grid cell-hours (days) >= NAAQS within the nonattainment area
- Percent change in maximum modeled 8-hour ozone within the nonattainment area

¹⁰¹ Care should be taken in interpreting absolute metrics if the model evaluation shows a large underprediction or overprediction of ozone or PM_{2.5} concentrations. An underprediction of observed concentrations will make it artificially easy to show progress towards absolute attainment levels and an overprediction will make it artificially difficult to show progress towards attainment.

¹⁰² For each of these metrics, the appropriate comparison to the level of the NAAQS is 70 ppb for 8-hour ozone; 35 µg/m³ for 24-hour PM_{2.5}; and 12 µg/m³ for annual PM_{2.5}.

While these metrics can be used to estimate the magnitude, frequency, and relative amount of ozone or PM_{2.5} reductions from any given future emissions scenario, there are no threshold quantities of these metrics that can directly translate to an attainment determination.

Generally, a large reduction in the frequency, magnitude, and relative amount of 8-hour ozone nonattainment (i.e., ≥ 71 ppb) or PM_{2.5} nonattainment (24-hour and/or annual) is consistent with a conclusion that a proposed strategy would meet the NAAQS. In the context of a weight of evidence determination, these metrics could be used to suggest that a particular location may be “stiff” or relatively unresponsive to emissions controls, while the rest of the modeling domain/nonattainment area is projected to experience widespread reductions.

6.1.2 Analyses and Trends in Ambient Air Quality and Emissions

Generally, air quality models are regarded as the most appropriate tools for assessing the expected impacts of a change in emissions. However, it may also be possible to evaluate progress towards attainment of the ozone or PM_{2.5} NAAQS based on measured historical trends of air quality and emissions. It may be possible to develop a relationship between past emissions changes and historical and current air quality. Once the relationship between past/present emissions and air quality is established, a response to the expected emissions reductions from a particular control strategy can be estimated. There are several elements to this analysis that are difficult to quantify. First, in most cases, the ambient data trends are best assessed by normalizing to account for year-to-year meteorological variations. Second, one must have an accurate accounting of the year-to-year changes in actual emissions (NO_x, VOC, and/or SO₂ and NH₃) for the given area and any surrounding areas whose emissions may impact local concentrations. Third, one must have a solid conceptual model of how ozone or PM_{2.5} is formed in the local area (e.g., influence of meteorology, NO_x-limited, ammonia limited, transport-influenced, etc.).

If available, meteorologically adjusted ozone and PM_{2.5} concentrations can be used to establish air quality trends. There are several techniques that have been used to examine the influence of meteorology on air quality. Among them are (a) statistical modeling (U.S. EPA, 2005b); (b) filtering techniques (Rao, 1995; Flaum, 1996; Milanchus, 1998; and Hogrefe, 2000), (c) using a probability distribution of meteorological severity based on climatological data (Cox and Chu, 1993, 1996), and (d) using CART analysis to identify meteorological classes and selecting days from each year so that the underlying frequency of the identified meteorological classes remains the same (Deuel and Douglas, 1996). Most of this work has examined the relationship between ozone and meteorology. Only recently have analyses examined the relationship between meteorology and PM_{2.5}. Additionally, compared to PM_{2.5}, the established relationship

between ozone and meteorological variables is generally stronger (higher r-square values). In the case of PM_{2.5}, the relationship between concentration and meteorology is complicated by the fact that PM_{2.5} components experience high concentrations at different times of the year and for different reasons. This makes it more difficult to meteorologically adjust PM_{2.5} concentrations.

If a meteorologically adjusted trend in ozone or PM_{2.5} can be estimated, then the information can be used to establish a link between emissions and air quality trends. This is not always straightforward due to the multitude of emissions precursors that may lead to high ozone and PM_{2.5} concentrations. A careful analysis of (meteorologically adjusted) air quality trends and emissions trends of each of the ozone and PM precursors (as well as primary PM) is needed to fully establish relationships. Detailed emissions information as well as a solid understanding of the conceptual model of ozone or PM_{2.5} formation is needed. If a trend can be established based on past emissions changes and air quality changes, then future year predicted emissions levels can be used to extrapolate future air quality.

Meteorologically adjusted trends in ozone and/or PM_{2.5} attempt to adjust observed concentrations to levels which would have been observed during average meteorological conditions (Camalier, 2007). This makes it easier to observe trends primarily due to emissions changes and also allows identification of years with above average or below average meteorologically conducive conditions. Identification of “extreme” meteorological conditions, which are not likely to re-occur in a particular design value period, can be used as part of a weight of evidence analysis. For example, the presence of one or more “extreme” (high concentration) meteorological years in either the base year period or the most recent design value period may make it appear that an area is farther away from attaining the NAAQS than would otherwise be the case if more typical meteorological conditions had occurred. It is important to note that 1 or more years of meteorological conditions which are not conducive to ozone formation will have the opposite effect. An area may appear to be on track to attain the NAAQS (or close to attaining) but, in reality, may need substantial additional emissions reductions in order to attain under average or above average meteorological conditions. Meteorological adjusted concentration and/or design value calculations can help explain both of these situations. More information on meteorologically adjusted ozone trends can be found [here](#).

A simpler (and more uncertain) way to qualitatively assess progress toward attainment is to examine recently observed air quality and emissions trends. Downward trends in observed concentrations and in emissions (past and projected) are consistent with progress towards

attainment. Strength of the evidence produced by emissions and air quality trends is increased if an extensive monitoring network exists and if there is a strong, positive and demonstrable, correlation between past emissions reductions and current trends in ozone or PM_{2.5}. Until recently, EPA prepared annual air quality trends reports for all criteria pollutants. The latest trends report analyzes ambient data through 2017 and can be found [here](#).

The appropriate weight given to trend analyses depends on several factors. Analyses that use more air quality data and apply a greater variety of trend parameters typically provide more credible results. More weight can be placed on the results if the procedure used to normalize the trend for meteorological differences explains much of the variability attributable to these differences. In addition, trend analysis is usually more reliable if the extrapolation (as applicable) does not extend very far into the future. Finally, trend analysis is most credible if the contemplated strategy is similar to a past strategy (e.g., both strategies focus on reducing sulfates for PM or NO_x for ozone). For example, if a past strategy focused on reducing sulfates, but a future one envisions controlling OC, there is no guarantee that ambient OC will respond similarly to changes in past emissions.

In addition to ambient data trends, further analysis of ambient data can provide information on ozone production efficiency, evidence of transport and assist in the quality assurance of emissions inputs. In particular, photochemical assessment monitoring station (PAMS) data, special study data, research and non-routine ambient data (i.e., NO_y, and VOC data) can provide insights into the ozone and/or PM_{2.5} concentrations observed in the nonattainment area and can help assess the accuracy of the modeling results and control strategies that are being relied upon for attainment.

6.1.3 Additional Emissions Controls/Reductions

Models are used to predict the future expected concentrations of ozone and/or PM_{2.5}, based on modeled emissions changes between a base year and future year. It is expected that emission inventories are as accurate as possible and represent emissions changes (including growth and controls) that are expected to occur. However, there may be various emissions sources and/or controls that are difficult to accurately represent in the modeling analysis, and the effects of some emissions controls may be difficult to quantify. Additionally, there may be uncertainty in how emissions controls may be implemented either in a nonattainment area, or in upwind regions which may contribute ozone to the nonattainment area.

The following are some of the types of control measures that may be appropriate to include in a weight of evidence demonstration:

- Measures that are difficult to quantify or may not be enforceable in the SIP. Examples include:
 - Energy efficiency or renewable energy (EE/RE) programs may be implemented statewide (and in fact may be enforceable). However, emissions reductions from such programs are hard to quantify and it may be difficult to assign reductions to particular utility sources. EPA has provided an [“EE/RE Roadmap Manual.”](#) The roadmap includes a weight of evidence “pathway” for air agencies that want to acknowledge the emissions benefits and potential reductions from EE/RE measures, but are unable to accurately quantify the emissions reductions in their SIP.
 - Smart growth initiatives such as land use planning and transportation planning.
 - Truck stop electrification.
 - Emissions reductions from idling regulations which may not be quantified in the mobile emissions modeling.
- Voluntary measures
 - Air agencies may have implemented voluntary measures that are not enforceable and therefore are not included in the SIP. These could include measures such as “ozone action days,” voluntary no burn days, telework programs, idling reduction initiatives, etc. Even though these programs may be voluntary, they can still lead to positive actions in the nonattainment area that can lead to lower emissions. Voluntary measures should be documented to the fullest extent possible, including estimates of emissions benefits, where possible.
- Regional/super-regional and/or national programs that may not have been accounted for in the attainment demonstration.
 - Federal measures which were not accounted for in the modeling because they were proposed and/or finalized after the state modeling was completed.
 - Upwind regional, state, and/or local measures which were not known or not able to be quantified in the attainment demonstration due to timing or lack of information.

6.2 Weight of Evidence Summary

A weight of evidence (WOE) determination may examine results from a diverse set of analyses, including the outcome of the primary attainment test, and attempts to summarize the results into an aggregate conclusion with respect to whether a chosen set of control measures are

likely to result in an area attaining the NAAQS by the applicable attainment date, notwithstanding what the air quality modeling may suggest in isolation. The supplemental analyses discussed above can be part of a WOE determination, although the level of detail required in a WOE submittal will vary as a function of many elements of the model application (e.g., model performance, degree of residual nonattainment in the modeled attainment test, amount of uncertainty in the model and its inputs, etc.). Each WOE determination will be subject to area-specific conditions and data availability. Area-specific factors may also affect the types of analyses that are feasible for a specific nonattainment area, as well as the significance of each. Thus, decisions concerning which analyses to perform, and how much credence to give each, need to be made on a case-by-case basis by those implementing the modeling/analysis protocol. Air agencies are encouraged to consult with their EPA Regional office (and Federal Land Managers, when appropriate) in advance of initiating supplemental analyses to determine which additional analyses may be most appropriate for their particular area for potential use as part of a WOE evaluation.

The most useful supplemental analyses are those providing the best evidence as to how much air quality improvement can be expected as compared to the improvement projected by the air quality modeling analysis. Each analysis is weighed qualitatively, depending on: 1) the capacity of the analysis to address the adequacy of a strategy and 2) the technical credibility of the analysis. If the overall WOE produced by the combination of the primary modeling analysis and the various supplemental analyses supports the attainment hypothesis, then the air agency can demonstrate attainment of the NAAQS proposed control strategy. The end product of a WOE determination is a document which describes analyses performed, databases used, key assumptions and outcomes of each analysis, and why an air agency believes that the evidence, viewed as a whole, supports a conclusion that the area will, or will not, attain the NAAQS. In conclusion, the basic criteria required for an attainment demonstration based on weight of evidence are as follows:

- 1) A fully-evaluated, high-quality modeling analysis that projects future values that are close to the NAAQS.
- 2) A description and explanation of each of the individual supplemental analyses, preferably from multiple categories. Analyses that utilize well-established analytical procedures and are grounded with sufficient data should be weighted accordingly higher.
- 3) A written description as to why the full set of evidence leads to a conclusive determination regarding the future attainment status of the area that differs from the results of the modeled attainment test alone.

7.0 What Role Should Additional and/or Supplemental Analyses Play in Regional Haze Modeling Demonstrations?

We believe additional and/or supplemental analyses can be a useful tool for air agencies when developing RPGs and applying them in the ways described in section 5. In this subsection, we note some potential supplemental analyses that may be used in this context.

7.1 Additional air quality modeling

Sensitivity tests can be performed to see if conclusions about trends in the 20% most anthropogenically impaired days and 20% clearest days are robust. One example of such an analysis is applying a model with and without a more finely resolved nested grid near source areas or near Class I areas. A purpose of this would be to see whether conclusions are affected by the degree of detail in which nearby sources are considered. A second example of an analysis would be to consider alternative future emissions (including lateral boundary conditions) and/or differing growth rate assumptions. This may be a particular concern for regional haze analyses because the emissions projection period is generally longer than for most ozone and PM_{2.5} attainment demonstrations. Uncertainty in emissions and growth rates become more important as the projection period is lengthened.

If the outcomes of the several comparisons described in section 5.1 are similar using sensitivity tests, alternative models and/or alternative modeling approaches, this finding supports conclusions reached in the main analysis.

7.2 Review of trends

A review of trends generally involves a comparison, sometimes qualitative, between past trends in reconstructed visibility and estimated changes in emissions (e.g., mid '00's to mid '10's). This information could be used to confirm that additional reductions of previously controlled emissions of a component or its precursors is likely to result in the predicted visibility improvement. It may also be used to see whether certain PM components are becoming increasingly more or less important sources of light extinction.

7.3 Other models and tools

Trajectory models may be useful for identifying the types of meteorological conditions most often corresponding to observed worst and best visibility in various Class I areas. This, in turn,

may enable air agencies to draw inferences about the areas containing sources most likely to influence visibility in a Class I area on days with “poor” and “good” visibility. Grid model-based techniques such as DDM or source apportionment may also be useful in identifying areas and emissions sources most responsible for visibility impairment on the most anthropogenically impaired days and clearest days.

7.4 Refinements to the recommended visibility analysis

A state may consider refining the recommended modeling analysis in some manner. Refinements are best made if they are based on local observations/analyses which suggest that some of the underlying assumptions in the recommended assessment may not be applicable. We list some potential refinements that could be considered. The list is intended to illustrate types of additional analyses that could be performed.

- Use an alternative light extinction equation or an area-specific version.
- The 20% most anthropogenically impaired days conceptually will not include days with high impacts from fires or dust storms because anthropogenic impairment relative to natural conditions will be low on such days. However, the particular method initially applied to identify the most anthropogenically impaired days may not implement this concept perfectly at a particular Class I area. Available speciated data and other information may be reviewed to see whether the outcome of the visibility analysis is being influenced by including one or more days with extraordinary events (e.g., a major wildfire lasting a number of days or transported dust events). If convincing arguments can be made that the event is a “natural” one, changes in the initial approach to estimate daily anthropogenic versus natural light extinction should be discussed with the appropriate EPA Regional office and Federal Land Managers.
- Daily component specific RRFs can be examined to determine if one or more days are responding in a different way compared to the majority of the clearest or most impaired days. Determining why days may be more or less responsive to emissions controls may lead to conclusions regarding the suitability of particular days to be represented in the mean response. It may be appropriate, in some cases, to re-calculate mean RRFs with suspect days removed.
- Re-rank future estimated light extinction (i.e., b_{ext} values) for all days that have current measurements and re-compute mean future most impaired and clearest days visibility (i.e., do not assume that the identity of clearest days remains the same between the base year and the future year).

7.5 Concerns about modeling the clearest days

In some parts of the U.S., concentrations of the components of PM used in visibility calculations may be very close to background levels on the clearest days. Measurements and model estimates may be subject to more relative uncertainty (i.e., lower signal to noise ratio) on days where observed concentrations of PM are very low (and light extinction is also low). The utility of a WOE determination is heightened in such cases. An air agency should see whether a model's inability to accurately predict one or more individual components of PM has a substantial effect on the extinction coefficient calculated with Equation (5.1). If it does, and diagnostic tests are unable to resolve a performance problem, an air agency may need to address the "no degradation" requirement for the clearest days in the particular Class I area(s) without using results from a grid model.

8.0 References

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Control Techniques Guidelines for the Oil and Natural Gas Industry

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U.S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
Sector Policies and Programs Division
Research Triangle Park, North Carolina

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ACRONYMS AND ABBREVIATIONS

Acronyms/Abbreviations	Description
ACA	Air Compliance Advisor
ANGA	America's Natural Gas Alliance
APCD	Air Pollution Control District
API	American Petroleum Institute
AQMD	Air Quality Management District
ARCADIS	a global consulting firm
bbl/day	barrels per day
boe/day	barrels of oil equivalent per day
BSER	best system of emission reduction
BTEX	benzene, toluene, ethylbenzene and xylenes
Btu	British thermal unit
Btu/scf	British thermal unit per standard cubic feet
CAA	Clean Air Act
CETAC-WEST	Canadian Environmental Technology Advancement Corporation-WEST
Cfm	cubic foot per minute
CFR	Code of Federal Regulations
CH ₄	methane
CMSA	Consolidated Metropolitan Statistical Area
CO	carbon monoxide
CO ₂	carbon dioxide
CTG	Control Techniques Guidelines
E&P Tanks Program	is a personal computer-based software designed to use site-specific information to predict emission from petroleum production storage tanks
ERG	Eastern Research Group
EVRU	ejector vapor recovery units
FIP	Federal Implementation Plan
FR	Federal Register
FRED	Federal Reserve Economic Data
G	Gram
GDP	gross domestic product
GHG	greenhouse gas
GHGRP	Greenhouse Gas Reporting Program
GRI	Gas Research Institute
HAP	hazardous air pollutants

Acronyms/Abbreviations	Description
HPDI database	provides production data and web-enabled analytical software tools for a wide range of oil and gas related customers
H ₂ S	hydrogen sulfide
ICF International	a firm that provides professional services and technology solutions in strategy and policy analysis, program management, project evaluation, and other services
IR	infrared
kg/hr/comp	kilogram per hour per component
kg/hr/source	kilogram per hour per source
kPa	kilopascals
kW	kilowatt
LAER	lowest achievable emission rate
LDAR	leak detection and repair
Mcf	thousand cubic feet
MMcf/yr	million cubic feet per year
NA	Nonattainment
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGL	natural gas liquids
NO _x	nitrogen oxide
NSPS	New Source Performance Standards
O&M	operation & maintenance
OAQPS	Office of Air Quality Planning and Standards
OCCM	OAQPS Control Cost Manual
OEL	open-ended lines
OGI	optical gas imaging
OTR	Ozone Transport Region
OVA	organic vapor analyzer
PG&E	Pacific Gas & Electric
PNAS	Proceedings of the National Academy of Sciences
ppm	parts per million
Ppmv	parts per million by volume
PRV	pressure relief valve
Psi	pounds per square inch
Psia	pounds per square inch absolute
Psig	pounds per square inch gauge
PTE	potential to emit
RACT	reasonably available control technology
RBLC	RACT/BACT/LAER Clearinghouse
Scf	standard cubic feet
Scfh	standard cubic feet per hour

Acronyms/Abbreviations	Description
scfh-cylinder	standard cubic feet per hour-cylinder
Scfm	standard cubic feet per minute
SIP	State Implementation Plan
SO ₂	sulfur dioxide
STSD	supplemental technical support document
THC	total hydrocarbons
TOC	total organic compounds
Tpy	tons per year
TSD	technical support document
TVA	toxic vapor analyzer
U.S.	United States
U.S. EIA	U.S. Energy Information Administration
U.S. EPA	U.S. Environmental Protection Agency
VOC	volatile organic compound
VRU	vapor recovery unit

1.0 INTRODUCTION

Section 172(c)(1) of the Clean Air Act (CAA) provides that state implementation plans (SIPs) for nonattainment areas must include “reasonably available control measures” including “reasonably available control technology” (RACT), for existing sources of emissions. CAA Section 182(b)(2)(A) provides that for Moderate ozone nonattainment areas, states must revise their SIPs to include RACT for each category of volatile organic compound (VOC) sources covered by control techniques guidelines (CTG) documents issued between November 15, 1990, and the date of attainment. Section 182(c) through (e) applies this requirement to states with ozone nonattainment areas classified as Serious, Severe, and Extreme. CAA Section 184(b) requires that states in ozone transport regions must revise their SIPs to implement RACT with respect to all sources of VOC in the state covered by a CTG issued before or after November 15, 1990. CAA Section 184(a) establishes a single Ozone Transport Region (OTR) comprised of the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont and the Consolidated Metropolitan Statistical Area (CMSA) that includes the District of Columbia.

The U.S. Environmental Protection Agency (EPA) defines RACT 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.” 44 FR 53761 (September 17, 1979).

This CTG provides recommendations to inform state, local, and tribal air agencies (hereafter, collectively referred to as air agencies) as to what constitutes RACT for select oil and natural gas industry emission sources. Air agencies can use the recommendations in the CTG to inform their own determination as to what constitutes RACT for VOC for the emission sources presented in this document in their Moderate or higher ozone nonattainment area or state in the OTR. The information contained in this document is provided only as guidance. This guidance does not change, or substitute for, requirements specified in applicable sections of the CAA or the EPA’s regulations; nor is it a regulation itself. This document does not impose any requirements on facilities in the oil and natural gas industry. It provides only recommendations for air agencies to consider in determining RACT. Air agencies may implement other

technically-sound approaches that are consistent with the CAA, the EPA's implementing regulations, and policies on interpreting RACT.

The recommendations contained in this CTG are based on data and information currently available to the EPA. The EPA evaluated the sources of VOC emissions in the oil and natural gas industry and the available control approaches for addressing these emissions, including the costs of such approaches. The recommendations contained in this CTG may not be appropriate for every situation based upon the circumstances of a specific source (e.g., VOC content of the gas, safety concerns/reasons). Regardless of whether an air agency chooses to adopt rules implementing the recommendations contained herein, or to issue rules that adopt different approaches for RACT for VOC from oil and natural gas industry sources, air agencies must submit their RACT rules to the EPA for review and approval using the SIP process. The EPA will evaluate the RACT determinations and determine, through notice and comment rulemaking, whether these determinations in the submitted rules meet the RACT requirements of the CAA and the EPA's regulations. To the extent an air agency adopts any of the recommendations in this guidance into its RACT rules, interested parties can raise questions and objections about the appropriateness of the application of this guidance to a particular situation during the development of these rules and the EPA's SIP process. Such questions and objections can relate to the substance of this guidance.

Section 182(b)(2) of the CAA requires that a CTG document issued between November 15, 1990, and the date of attainment include the date by which states subject to CAA section 182(b) must submit SIP revisions. Accordingly, the EPA is setting forth a 2-year period, from the date of publication of the notice of availability of this CTG in the *Federal Register* for the required SIP submittal.

2.0 BACKGROUND AND OVERVIEW

There have been several federal and state actions to reduce VOC emissions from certain emission sources in the oil and natural gas industry. A summary of these actions is provided below.

2.1 History of New Source Performance Standards that Regulate Emission Sources in the Oil and Natural Gas Industry

In 1979, the EPA listed crude oil and natural gas production on its priority list of source categories for promulgation of NSPS (44 FR 49222, August 21, 1979). Since the 1979 listing, the EPA has promulgated performance standards to regulate VOC emissions from production, processing, transmission, and storage as well as sulfur dioxide (SO₂) emissions from natural gas processing emission sources and, more recently, greenhouse gases (GHG). On June 24, 1985 (50 FR 26122), the EPA promulgated an NSPS for natural gas processing plants that addressed VOC emissions from leaking components (40 CFR part 60, subpart KKK). On October 1, 1985 (50 FR 40158), a second NSPS was promulgated for natural gas processing plants that regulated SO₂ emissions (40 CFR part 60, subpart LLL). On August 16, 2012 (77 FR 49490) (2012 NSPS), the EPA finalized its review of NSPS standards for the listed oil and natural gas source category and revised the NSPS for VOC from leaking components at natural gas processing plants, and the NSPS for SO₂ emissions from natural gas processing plants. At that time, the EPA also established standards for certain oil and natural gas emission sources not covered by the existing standards. In addition to the emission sources that were covered previously, the EPA established new standards to regulate VOC emissions from hydraulically fractured gas wells, centrifugal compressors, reciprocating compressors, pneumatic controllers, and storage vessels. In 2013 (78 FR 58416) (2013 NSPS Reconsideration) and 2014 (79 FR 79018), the EPA amended the standards set in 2012 in order to improve implementation of the standards. In 2016 (81 FR 35824, June 3, 2016), the EPA finalized new standards to regulate GHG and VOC emissions across the oil and natural gas source category. Specifically, the EPA finalized both GHG standards (in the form of limitations on methane emissions) and VOC standards for several emission sources not previously covered by the NSPS (i.e., hydraulically fractured oil well completions, pneumatic pumps, and fugitive emissions from well sites and compressor stations).

In addition, the EPA finalized GHG standards for certain emission sources that were regulated for only VOC (i.e., hydraulically fractured gas well completions, centrifugal compressors, reciprocating compressors, pneumatic controllers and equipment leaks at natural gas processing plants). With respect to certain equipment that are used across the industry, 40 CFR part 60 subpart OOOO regulates only a subset of these equipment (pneumatic controllers, centrifugal compressors, reciprocating compressors). The final amendments established GHG standards (40 CFR part 60 subpart OOOOa) for these equipment and extended the current VOC standards to previously unregulated equipment. Although not regulated under the oil and natural gas NSPS, stationary reciprocating internal combustion engines and combustion turbines used in the oil and natural gas industry are covered under separate NSPS specific to engines and turbines (40 CFR part 60, subparts IIII, JJJJ, GG, KKKK).

In addition to NSPS issued to regulate VOC emissions from the oil and gas industry, the EPA also published a CTG document that recommended the control of VOC emissions from equipment leaks from natural gas processing plants in 1983 (1983 CTG; 49 FR 4432; February 6, 1984).¹ This 2016 CTG is the only CTG document issued since 1983 for the oil and natural gas industry.

2.2 State and Local Regulations

Several states regulate VOC emissions from storage vessels in the oil and natural gas industry. There are also a few states (e.g., Colorado, Wyoming, and Montana) that have established specific permitting requirements or regulations that control VOC emissions from emission sources in the oil and natural gas industry (e.g., compressors, pneumatics, fugitive emission components):

- (1) The Colorado Department of Public Health and Environment, Air Quality Control Commission has developed emission regulations 3, 6, and 7 that apply to oil and natural gas industry emission sources in Colorado.
(<https://www.colorado.gov/pacific/cdphe/summary-oil-and-gas-emissions-requirements>.)
- (2) Montana requires oil and gas well facilities to control emissions from the time the well is completed until the source is registered or permitted (Registration of Air Contaminant

¹ U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC, 27711. *Guideline Series. Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants*. December 1983. EPA-450/3-83-007.

Sources Rule, Rule 17.8.1711, Oil or Gas Well Facilities Emission Control

Requirements). (<http://www.mtrules.org/gateway/ruleno.asp?RN=17%2E8%2E1711>.)

- (3) The Wyoming Department of Environmental Quality limits VOC emissions from existing sources in ozone nonattainment areas and has issued specific permitting guidance that apply to oil and natural gas facilities. (Chapter 6, Section 2 Permitting Guidance, last revised in September 2013).
- (4) The San Joaquin Valley Air Pollution Control District requires control of VOC emissions from several VOC oil and natural gas emission sources, including, but not limited to, (a) storage vessels, (b) crude oil production sumps, (c) components at light crude oil production facilities, natural gas production facilities and natural gas processing facilities, and (d) in-situ combustion well vents.

In some states, general permits have been developed for oil and natural gas facilities.

General permits are permits where all the terms and conditions of the permit are developed for a given industry and authorize the construction, modification, and/or operation of facilities that meet those terms and conditions. For example, West Virginia, Ohio, and Pennsylvania have developed General Air Permits for the oil and natural gas industry. The Pennsylvania Department of Environmental Protection has issued a General Permit, General Plan Approval and Permit Exemption 38 for natural gas dispensing facilities and oil and gas exploration, development, and production operations. Pennsylvania also applies conditions on flaring of emissions. Under the Permit 38 exemptions, there are criteria set out for the oil and natural gas industry that include unconditionally exempt and conditionally exempt criteria. Unconditionally exempt operations/equipment include conventional wells, conventional wellheads and associated equipment, well drilling, completion and work-over activities, and non-road engines. Unconventional wells, wellheads and associated equipment (including equipment components, storage vessels) are conditionally exempt. Conditions include compliance with 40 CFR part 60, subpart OOOO and Pennsylvania's General Permit 5 (GP-5) and a demonstration that the combined VOC emissions from all sources at a facility are less than 2.7 tons per year

(tpy) on a 12-month rolling basis. For oil and natural gas facilities that do not meet these conditions, a case-by-case plan approval is required.²

There may also be local permit requirements for control of VOC emissions from existing sources of VOC emissions in the oil and natural gas industry, such as those required by the Bay Area Air Quality Management District (BAAQMD) for pneumatic controllers. The BAAQMD requires that a permit to operate applicant provide the number of high-bleed and low-bleed pneumatic devices in their permit application. Facilities that use high-bleed devices might be required to provide device-specific bleed rates and supporting documentation for each high-bleed device. In cases where emissions are high from high-bleed devices, BAAQMD might require that the facility conduct fugitive monitoring and/or control requirements under conditions of their permit to operate³ on a case-by-case basis.

We conducted a search of the EPA's RACT/BACT/LAER Clearinghouse (RBLC) and identified several draft and final permits that covered some of the sources evaluated for RACT in this CTG. The controls specified in these permits are similar to the control options evaluated in this CTG.⁴

We considered these existing state and local requirements limiting VOC emissions from the oil and natural gas industry in preparing this guideline.

2.3 Development of this CTG

As discussed in section 2.1 of this chapter, the NSPS established VOC emission standards for certain new and modified sources in the oil and gas industry. This CTG addresses existing sources of VOC emissions and provides recommendations for RACT for the oil and natural gas industry. We developed our RACT recommendations after reviewing the 1983 CTG document, the oil and natural gas NSPS, existing state and local VOC emission reduction approaches, and information on costs, emissions and available VOC emission control technologies. In April 2014, the EPA released five technical white papers on potentially significant sources of emissions in the oil and natural gas industry. The white papers focused on

² Pennsylvania Department of Environmental Protection. *Comparison of Air Emission Standards for the Oil & Natural Gas Industry* (Well Pad Operations, Natural Gas Compressor Stations, and Natural Gas Processing Facilities). May 23, 2014.

³ Cheng, Jimmy. *Permit Handbook. Chapter 3.5 Natural Gas Facilities and Crude Oil Facilities*. Bay Area Air Quality Management District. September 16, 2013.

⁴ RACT/BACT/LAER Clearinghouse website: <http://cfpub.epa.gov/RBLC/>.

technical issues covering emissions and mitigation techniques that target methane and VOC. We reviewed the white papers, along with the input we received from the peer reviewers and the public, when evaluating and recommending RACT.

This CTG reflects the evaluation of potential RACT options for emission sources that are regulated under the oil and natural gas NSPS. This CTG did not evaluate hydraulically fractured oil and natural gas well completions performed on existing wells because these operations are addressed in the NSPS.

Several of the technical support documents (TSDs) prepared in support of the NSPS actions for the oil and natural gas industry include data and analyses considered in developing RACT recommendations in this CTG. To the extent that the data and analyses are also relevant to control options for existing sources, they are referred to throughout this guidance document as follows:

- (1) The TSD for the 2011 NSPS proposal, published in July, 2011 is referred to as the “2011 NSPS TSD”.⁵
- (2) The supplemental TSD for the 2012 final NSPS standards, published in April, 2012, is referred to as the “2012 NSPS TSD” or “2012 NSPS STSD”.⁶
- (3) The TSD for the 2015 proposal NSPS standards, published August, 2015, is referred to as the “2015 NSPS TSD”.⁷
- (4) The TSD for the 2016 final NSPS standards, published in May, 2016, is referred to as the “2016 NSPS TSD”.⁸

Additionally, emission information and counts for various emission sources were summarized from facility-level data submitted to the Greenhouse Gas Reporting Program

⁵ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution – Background Technical Support Document for Proposed Standards*. July 2011. EPA-453/R-11002.

⁶ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. Docket ID No. EPA-HQ-OAR-2010-0505-4550.

⁷ U.S. Environmental Protection Agency. *Oil and Natural Gas Source Category: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Technical Support Document for the Proposed Amendments to the New Source Performance Standards*. August 2015. (See Docket No. EPA-HQ-OAR-2010-0505-5021; regulations.gov).

⁸ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources – Background Technical Support Document for the Final New Source Performance Standards*. May 2016.

(GHGRP)⁹ and data used to calculate national emissions in the Inventory of U.S. Greenhouse Gas Emissions and Sinks (GHG Inventory).¹⁰ For the purposes of this document, these data sources are referred to as the “GHGRP” and the “GHG Inventory”. The most recent published data from the GHG Inventory when we prepared the draft CTG was for 2013, and was used for some of the analyses included in this document. Between the time we issued the draft CTG and the final CTG, GHGRP data was released that covers 2011 through 2014 and the most recent available GHG Inventory covers data from 1990 through 2014. These new activity data have been reviewed for this CTG and incorporated into our RACT analyses, as appropriate.

Most of the VOC emission estimates presented in this document are based on methane emissions data because we only had methane emissions information for the evaluated sources. We calculated VOC emissions using ratios of methane to VOC in the gas for the different segments of the industry. These ratios, and the procedures used to calculate them, are documented in a memorandum characterizing gas composition developed during the NSPS process.¹¹ Herein, we refer to this memorandum as the “2011 Gas Composition Memorandum”. Because methane emissions are the basis for most of our VOC emission estimates, in several instances where we provide VOC emissions per source/model plant, we also provide the methane emissions that are the basis for our VOC emission estimates.

The remainder of this document is divided into seven chapters and an appendix. Chapter three describes the oil and natural gas industry and a summary of our RACT recommendations presented in this CTG. Chapters four through nine describe the oil and natural gas emission sources that we evaluated for our RACT recommendations (i.e., storage vessels, compressors, pneumatic controllers, pneumatic pumps, equipment component leaks from natural gas processing plants, and fugitive emissions from well sites and gathering and boosting stations), available control and regulatory approaches (including existing federal, state and local requirements) and the potential emission reductions and costs associated with available control and regulatory approaches for a given emission source. The appendix provides example model

⁹ U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC. November 2014. (Reported Data: <http://www.epa.gov/ghgreporting/>). The Greenhouse Gas Reporting Program has particular definitions of “facility” for certain petroleum and natural gas systems industry segments. See 40 CFR 98.238.

¹⁰ U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990 - 2014*. Washington, DC. EPA 430-R-15-004. Available online at <https://www.epa.gov/ghgemissions/us-greenhouse-gas-inventory-report-1990-2014>.

¹¹ Memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. *Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking*. July 2011. Docket ID No. EPA-HQ-OAR-2010-0505-0084.

rule language that can be used by air agencies as a starting point in the development of their SIP rules if they choose to adopt the recommended RACT presented in this document.

3.0 OVERVIEW OF THE OIL AND NATURAL GAS INDUSTRY AND SOURCES SELECTED FOR RACT RECOMMENDATIONS

Section 3.1 presents an overall description of the oil and natural gas industry and section 3.2 presents the VOC emission sources for which we are recommending RACT within the oil and natural gas industry. Table 3-1 provides a summary of recommendations for controlling VOC emissions from oil and natural gas industry emission sources.

3.1 Overview of the Oil and Natural Gas Industry

The oil and natural gas industry includes oil and natural gas operations involved in the extraction and production of crude oil and natural gas, as well as the processing, transmission, storage, and distribution of natural gas. For oil, the industry includes all operations from the well to the point of custody transfer at a petroleum refinery. For natural gas, the industry includes all operations from the well to the customer. For purposes of this document, the oil and natural gas operations are separated into four segments: (1) oil and natural gas production, (2) natural gas processing, (3) natural gas transmission and storage, and (4) natural gas distribution. We briefly discuss each of these segments below. For purposes of this CTG, oil and natural gas production includes only onshore operations.

Production operations include the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, and separation or treating of oil and/or natural gas (including condensate). Production components may include, but are not limited to, wells and related casing head, tubing head, and “Christmas tree” piping, as well as pumps, compressors, heater treaters, separators, storage vessels, pneumatic devices, and dehydrators. Production operations also include well drilling, completion, and recompletion processes, which include all the portable non-self-propelled apparatus associated with those operations. Production sites include not only the “pads” where the wells are located, but also include stand-alone sites where oil, condensate, produced water and gas from several wells may be separated, stored and treated. The production segment also includes the low-pressure, small diameter, gathering pipelines and related components that collect and transport the oil, natural gas, and other materials and wastes from the wells to the refineries or natural gas processing plants.

There are two basic types of wells: oil wells and natural gas wells. Oil wells can have “associated” natural gas that is separated and processed or the crude oil can be the only product processed. Crude oil production includes the well and extends to the point of custody transfer to the crude oil transmission pipeline. Once the crude oil is separated from water and other impurities, it is essentially ready to be transported to the refinery via truck, railcar, or pipeline. The oil refinery sector is considered separately from the oil and natural gas industry. Therefore, at the point of custody transfer at the refinery, the oil leaves the oil and natural gas sector and enters the petroleum refining sector.

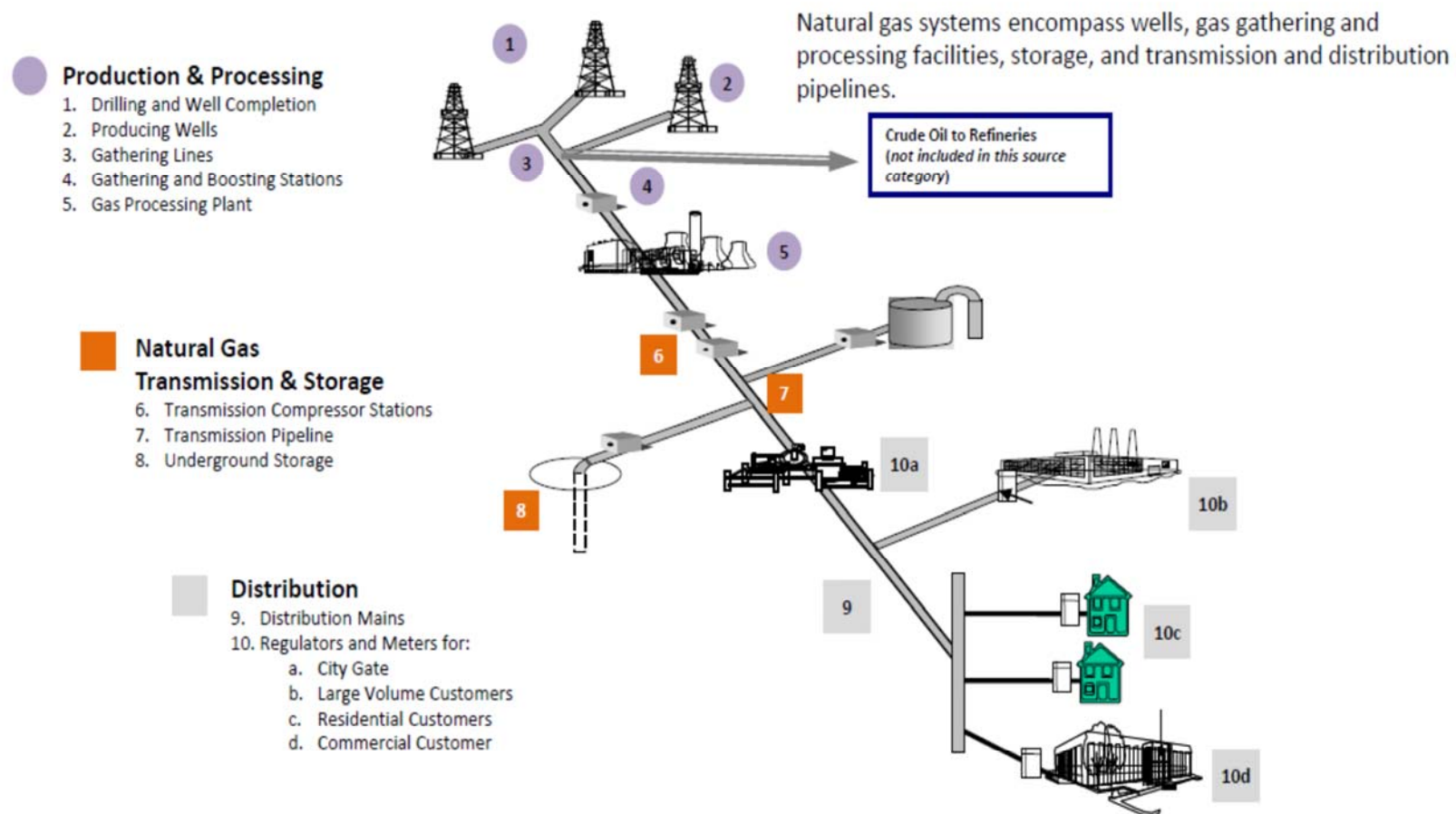
Natural gas is primarily made up of methane. It commonly exists in mixtures with other hydrocarbons. They are sold separately and have a variety of uses. The raw natural gas often contains water vapor, hydrogen sulfide (H_2S), carbon dioxide (CO_2), helium, nitrogen, and other compounds. Natural gas processing consists of separating certain hydrocarbons and fluids from the natural gas to produce “pipeline quality” dry natural gas. While some of the processing can be accomplished in the production segment, the complete processing of natural gas takes place in the natural gas processing segment. Natural gas processing operations separate and recover natural gas liquids (NGL) or other non-methane gases and liquids from a stream of produced natural gas through components performing one or more of the following processes: oil and condensate separation, water removal, separation of natural gas liquids, sulfur and CO_2 removal, fractionation of natural gas liquid, and other processes such as the capture of CO_2 separated from natural gas streams for delivery outside the facility.

The pipeline quality natural gas leaves the processing segment and enters the transmission and storage segment. Pipelines in the natural gas transmission and storage segment can be interstate pipelines that carry natural gas across state boundaries or intrastate pipelines, which transport the gas within a single state. While interstate pipelines may be of a larger diameter and operated at a higher pressure than intrastate pipelines, the basic components are the same. To ensure that the natural gas flowing through any pipeline remains pressurized, compression of the gas is required periodically along the pipeline. This is accomplished by compressor stations usually placed between 40 and 100 mile intervals along the pipeline. At a compressor station, the natural gas enters the station, where it is compressed by reciprocating or centrifugal compressors.

In addition to the pipelines and compressor stations, the natural gas transmission and storage segment includes aboveground and underground storage facilities. Underground natural gas storage includes subsurface storage, which typically consists of depleted gas or oil reservoirs and salt dome caverns used for storing natural gas. One purpose of this storage is for load balancing (equalizing the receipt and delivery of natural gas). At an underground storage site, there are typically other processes, including compression, dehydration, and flow measurement.

The distribution segment is the final step in delivering natural gas to customers. The natural gas enters the distribution segment from delivery points located on interstate and intrastate transmission pipelines to business and household customers. Natural gas distribution systems consist of thousands of miles of piping, including mains and service pipelines to the customers. Distribution systems sometimes have compressor stations, although they are considerably smaller than transmission compressor stations. Distribution systems include metering stations, which allow distribution companies to monitor the natural gas in the system. Essentially, these metering stations measure the flow of natural gas and allow distribution companies to track natural gas as it flows through the system.

Emissions can occur from a variety of processes and points throughout the oil and natural gas industry. Primarily, these emissions are organic compounds such as methane, ethane, VOC, and organic hazardous air pollutants (HAP). Figure 3-1 presents a schematic of oil and natural gas sector operations.



Source: Adapted from American Gas Association and EPA Natural Gas STAR Program

Figure 3-1. Oil and Natural Gas Sector Operations

3.2 Sources Selected For RACT Recommendations

This CTG covers select sources of VOC emissions in the onshore production and processing segments of the oil and natural gas industry (i.e., pneumatic controllers, pneumatic pumps, compressors, equipment leaks, fugitive emissions) and storage vessel VOC emissions in all segments (except distribution) of the oil and natural gas industry. These sources were selected for RACT recommendations because current information indicates that they are significant sources of VOC emissions. As mentioned in section 2.3, the VOC RACT recommendations contained in this document were made based on the review of the 1983 CTG document, the oil and natural gas NSPS, existing state and local VOC emission reduction approaches, and information on emissions, available VOC emission control technologies, and costs.

In considering costs, we compared control options and estimated costs and emission impacts of multiple emission reduction options under consideration. Recommendations are presented in this CTG for the subset of existing sources in the oil and natural gas industry where the application of controls is judged reasonable, given the availability of demonstrated control technologies, emission reductions that can be achieved, and the cost of control.

Table 3-1 presents a summary of the oil and natural gas emission sources and recommended RACT included in this CTG.

Table 3-1. Summary of the Oil and Natural Gas Industry Emission Sources and Recommended RACT Included in this CTG

Emission Source	Applicability	RACT Recommendations
Storage Vessels	Individual storage vessel with a potential to emit (PTE) greater than or equal to 6 tpy VOC.	95 percent reduction of VOC emissions from storage vessels. OR Maintain less than 4 tpy uncontrolled actual VOC emissions after having demonstrated that the uncontrolled actual VOC emissions have remained less than 4 tpy, as determined monthly, for 12 consecutive months.
Pneumatic Controllers	Individual continuous bleed, natural gas-driven pneumatic controller located at a natural gas processing plant.	Natural gas bleed rate of 0 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 0 scfh).
	Individual continuous bleed natural gas-driven pneumatic controller located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline.	Natural gas bleed rate less than or equal to 6 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 6 scfh).
Pneumatic Pumps	Individual natural gas-driven diaphragm pump located at a natural gas processing plant.	Zero VOC emissions.
	Individual natural gas-driven diaphragm pump located at a well site.	Require routing of VOC emissions from the pneumatic pump to an existing onsite control device or process.
		Require 95 percent control unless the onsite existing control device or process cannot achieve 95 percent.
		If onsite existing device or process cannot achieve 95 percent, maintain documentation demonstrating the percent reduction the control device is designed to achieve.

Emission Source	Applicability	RACT Recommendations
		If there is no existing control device at the location of the pneumatic pump, maintain records that there is no existing control device onsite.
	Individual natural gas-driven diaphragm pump located at a well site that is in operation for any period of time each calendar day for less than a total of 90 days per calendar year.	RACT would not apply.
Compressors (Centrifugal and Reciprocating)	Individual reciprocating compressor located between the wellhead and point of custody transfer to the natural gas transmission and storage segment.	Reduce VOC emissions by replacing reciprocating compressor rod packing on or before 26,000 hours of operation or 36 months since the most recent rod packing replacement. Alternatively, route rod packing emissions to a process through a closed vent system under negative pressure.
	Individual reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site.	RACT would not apply.
	Individual centrifugal compressor using wet seals that is located between the wellhead and point of custody transfer to the natural gas transmission and storage segment.	Reduce VOC emissions from each centrifugal compressor wet seal fluid gassing system by 95 percent.
	Individual centrifugal compressor using wet seals located at a well site, or an adjacent well site and servicing more than one well site.	RACT would not apply.
	Individual centrifugal compressor using dry seals.	RACT would not apply.
Equipment Leaks	Equipment components in VOC service located at a natural gas processing plant.	Implement the 40 CFR part 60, subpart VVa leak detection and repair (LDAR) program for natural gas processing plants.
Fugitive Emissions	Individual well site with wells with a gas to oil ratio (GOR) greater than or equal to 300, that produce, on average, greater than 15 barrel equivalents per well per day.	Develop and implement a semiannual optical gas imaging (OGI) monitoring and repair plan that covers the collection of fugitive emissions components at well sites within a company defined area. Method 21 can be

Emission Source	Applicability	RACT Recommendations
		used as an alternative to OGI at a 500 ppm repair threshold level.
	Individual gathering and boosting station located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or point of custody transfer to an oil pipeline.	Develop and implement a quarterly OGI monitoring and repair plan that covers the collection of fugitive emissions components at gathering and boosting stations within a company defined area. Method 21 can be used as an alternative to OGI at a 500 ppm repair threshold.
	Individual well site with a GOR less than 300.	RACT would not apply.

4.0 STORAGE VESSELS

Storage vessels are significant sources of VOC emissions in the oil and natural gas industry. This chapter provides a description of the types of storage vessels present in the oil and natural gas industry, and provides VOC emission estimates for storage vessels, in terms of mass of emissions per throughput, for both crude oil and condensate storage vessels. This chapter also presents control techniques used to reduce VOC emissions from storage vessels, along with their costs and potential emission reductions. Finally, this chapter provides a discussion of our recommended RACT for storage vessels.

4.1 Applicability

For purposes of this CTG, the emissions and emission controls discussed herein would apply to a tank or other vessel in the oil and natural gas industry that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of non-earthen materials (such as wood, concrete, steel, fiberglass, or plastic) that provide structural support. The emissions and emission controls discussed herein would not apply to the following vessels:

- (1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships), and are intended to be located at a site for less than 180 consecutive days.
- (2) Process vessels such as surge control vessels, bottoms receivers, or knockout vessels.
- (3) Pressure vessels designed to operate in excess of 204.9 kilopascals (29.7 pounds per square inch) and without emissions to the atmosphere.¹²

4.2 Process Description and Emission Sources

4.2.1 Process Description

Storage vessels in the oil and natural gas industry are used to hold a variety of liquids including crude oil, condensates, produced water, etc. While still underground and at reservoir pressure, crude oil contains many lighter hydrocarbons in solution. When the oil is brought to the

¹² It is acknowledged that even pressure vessels designed to operate without emissions have a small potential for fugitive emissions at valves. Valves are threaded components that would be subject to leak detection and repair requirements.

surface, many of the dissolved lighter hydrocarbons (as well as water) are removed through a series of separators. Crude oil is passed through either a two-phase separator (where the associated gas is removed and any oil and water remain together) or a three-phase separator (where the associated gas is removed and the oil and water are also separated). The remaining oil is then directed to a storage vessel where it is stored for a period of time before being transported off-site. Much of the remaining hydrocarbon gases in the oil are released from the oil as vapors in the storage vessels. Storage vessels are typically installed with similar or identical vessels in a group, referred to in the industry as a tank battery.

Emissions of the hydrocarbons from storage vessels are a function of flash, breathing (or standing), and working losses. Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas industry, flashing losses occur when crude oils or condensates flow into an atmospheric storage vessel from a processing vessel (e.g., a separator) operated at a higher pressure. Typically, the larger the pressure drop, the more flash emissions will occur in the storage vessel. The temperature of the liquid may also influence the amount of flash emissions. Breathing losses are the release of gas associated with temperature fluctuations and other equilibrium effects. Working losses occur when vapors are displaced due to the emptying and filling of storage vessels. The volume of gas vapor emitted from a storage vessel depends on many factors. Lighter crude oils flash more hydrocarbons than heavier crude oils. In storage vessels where the oil is frequently cycled and the overall throughput is high, working losses are higher. Additionally, the operating temperature and pressure of oil in the separator dumping into the storage vessel will affect the volume of flashed gases coming out of the oil.

The composition of the vapors from storage vessels varies, and the largest component is methane, but also may include ethane, butane, propane, and HAP such as benzene, toluene, ethylbenzene and xylenes (commonly referred to as BTEX), and n-hexane.

4.2.2 Emissions Data

4.2.2.1 *Summary of Major Studies and Emissions*

There are numerous studies and reports available that estimate storage vessel emissions. We consulted several of these studies and reports to evaluate the emissions and emission

reduction options for storage vessels. Table 4-1 presents a summary of the references for these reports, along with an indication of the type of information available in each reference.

Table 4-1. Major Studies Reviewed for Consideration of Emissions and Activity Data^{a,b}

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options ^e
VOC Emissions from Oil and Condensate Storage Tanks	Texas Environmental Research Consortium	2009	Regional	X	X
Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation – Final Report	Texas Commission on Environmental Quality	2009	Regional	X	
Initial Economic Impact Analysis for Proposed State Implementation Plan Revisions to the Air Quality Control Commission's Regulation Number 7	Colorado Air Quality Control Commission	2008	NA		X
E&P TANKS	API		National	X	
Inventory of U.S. Greenhouse Gas Emissions and Sinks ^c	EPA	Annual	National	X	
Greenhouse Gas Reporting Program (Annual Reporting: Current Data Available for 2011-2013) ^d	EPA	2014	Facility-Level	X	X

NA = Not Applicable.

^a U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket ID No. EPA-HQ-OAR-2010-0505-4550.

^b U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Technical Support*. July 2011. EPA-453/R-11-002.

^c U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. <https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html>.

^d U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC. November 2014.

^e An "X" in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

4.2.2.2 *Representative Storage Vessel Baseline Emissions*

Storage vessels vary in size and throughputs. In support of the 2013 NSPS Reconsideration,¹³ average storage vessel emissions, in terms of mass of emissions per throughput, were developed for both crude oil and condensate storage vessels.¹⁴ We also developed mass emissions per throughput estimates using the American Petroleum Institute's (API's) E&P TANKS program and more than 100 storage vessels across the country with varying characteristics.¹⁵ The VOC emissions per throughput estimates used for this analysis are:

- (1) Uncontrolled VOC Emissions from Crude Oil Storage Vessels = 0.214 tpy VOC/barrel per day (bbl/day); and
- (2) Uncontrolled VOC Emissions from Condensate Storage Vessels = 2.09 tpy VOC/bbl/day.

On a nationwide basis, there are a wide variety of storage vessel sizes, as well as rates of throughput for each tank. Emissions are directly related to the throughput of liquids for a given storage vessel; therefore, in support of the 2013 NSPS Reconsideration, we adopted production rate brackets developed by the U.S. Energy Information Administration (U.S. EIA) for our emission estimates. To estimate the emissions from an average storage vessel within each production rate bracket, we developed average production rates for each bracket. This average was calculated using the U.S. EIA published nationwide production per well per day for each production rate bracket from 2006 through 2009. Table 4-2 presents the average oil production and condensate production in barrels per well per day. For this analysis, we considered the liquid produced (as reported by the U.S. EIA) from oil wells to be crude oil and from gas wells to be condensate. Table 4-2 presents the average VOC emissions for each storage vessel within each production rate bracket calculated by applying the average production rate (bbl/day) to the VOC emissions per throughput estimates (tpy VOC/bbl/day).

¹³ 78 FR 58416, September 23, 2013. The EPA issued final updates to its 2012 VOC performance standards for storage tanks used in crude oil and natural gas production and transmission. The amendments reflected updated information that responded to issues raised in several petitions for reconsideration of the 2012 standards.

¹⁴ Brown, Heather, EC/R Incorporated. Memorandum prepared for Bruce Moore, EPA/OAQPS/SPPD/FIG. *Revised Analysis to Determine the Number of Storage Vessels Projected to be Subject to New Source Performance Standards for the Oil and Natural Gas Sector*. 2013.

¹⁵ American Petroleum Institute. *Production Tank Emissions Model. E&P Tank Version 2.0. A Program for Estimating Emissions from Hydrocarbon Production Tanks*. Software Number 4697. April 2000.

Table 4-2. Average Oil and Condensate Production and Storage Vessel Emissions per Production Rate Bracket¹⁶

Production Rate Bracket (BOE/day) ^a	Oil Wells		Gas Wells	
	Average Oil Production Rate per Oil Well (bbl/day) ^b	Crude Oil Storage Vessel VOC Emissions (tpy) ^c	Average Condensate Production Rate per Gas Well (bbl/day) ^b	Condensate Storage Vessel VOC Emissions (tpy) ^c
0-1	0.385	0.083	0.0183	0.038
1-2	1.34	0.287	0.0802	0.168
2-4	2.66	0.570	0.152	0.318
4-6	4.45	0.953	0.274	0.573
6-8	6.22	1.33	0.394	0.825
8-10	8.08	1.73	0.499	1.04
10-12	9.83	2.11	0.655	1.37
12-15	12.1	2.59	0.733	1.53
15-20	15.4	3.31	1.00	2.10
20-25	19.9	4.27	1.59	3.32
25-30	24.3	5.22	1.84	3.85
30-40	30.5	6.54	2.55	5.33
40-50	39.2	8.41	3.63	7.59
50-100	61.6	13.2	5.60	11.7
100-200	120	25.6	12.1	25.4
200-400	238	51.0	23.8	49.8
400-800	456	97.7	44.1	92.3
800-1,600	914	196	67.9	142
1,600-3,200	1,692	363	148	311
3,200-6,400	3,353	719	234	490
6,400-12,800	6,825	1,464	891	1,864
> 12,800 ^d	0	0	0	0

Minor discrepancies may be due to rounding.

^a BOE=Barrels of Oil Equivalent

^b Oil and condensate production rates published by U.S. EIA. “United States Total Distribution of Wells by Production Rate Bracket.”

^c Oil storage vessel VOC emission factor = 0.214 tpy VOC/bbl/day. Condensate storage vessel VOC emission factor = 2.09 tpy/bbl/day.

^d There were no new oil and gas well completions in 2009 for this rate category. Therefore, average production rates were set to zero.

¹⁶ Brown, Heather, EC/R Incorporated. Memorandum prepared for Bruce Moore, EPA/OAQPS/SPPD/FIG. *Revised Analysis to Determine the Number of Storage Vessels Projected to be Subject to New Source Performance Standards for the Oil and Natural Gas Sector*. 2013.

4.3 Available Controls and Regulatory Approaches

In analyzing available controls for storage vessels, we reviewed information obtained in support of the 2012 NSPS¹⁷ and the 2013 NSPS Reconsideration actions, control techniques identified in the Natural Gas STAR program, and existing state regulations that require control of VOC emissions from storage vessels in the oil and natural gas industry. Section 4.3.1 presents a non-exhaustive discussion of available VOC emission control methods for storage vessels. Section 4.3.2 includes a summary of the federal, state, and local regulatory approaches that control VOC emissions from crude oil and condensate storage vessels.

4.3.1 Available VOC Emission Control Options

The options generally used as the primary means to limit the amount of VOC vented are to: (1) route emissions from the storage vessel through an enclosed system to a process where emissions are recycled, recovered, or reused in the process – “route to a process” (e.g., by installing a vapor recovery unit (VRU) that recovers vapors from the storage vessel) for reuse in the process or for beneficial use of the gas onsite and/or (2) route emissions from the storage vessel to a combustion device. While EPA explored these options within the document, there may be other emission controls that sources may wish to employ to ensure continuous compliance with EPA’s RACT recommendation. Regardless of the type of emission control method that a source may choose to utilize, the recommended RACT level of control explained more fully below is meant to apply at all times. One of the clear advantages the first option has over the second option is that it results in a cost savings associated with the recycled, recovered and reused natural gas and other hydrocarbon vapor, rather than the loss and destruction of the natural gas and vapor by combustion. Combustion and partial combustion of organic pollutants also creates secondary pollutants including nitrogen oxides, carbon monoxide, sulfur oxides, carbon dioxide and smoke/particulates. These emission control methods are described below along with their emission reduction control effectiveness as they apply to storage vessels in the industry and the potential costs associated with their installation and operation.

¹⁷ *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standard for Hazardous Air Pollutants Reviews. Final Rule.* 77 FR 49490, August 16, 2012.

4.3.1.1 *Routing Emissions to a Process via a Vapor Recovery Unit (VRU)*

Description

One option for controlling storage vessel emissions is to route vapors from the storage vessel back to the inlet line of a separator, to a sales gas line, or to some other line carrying hydrocarbon fluids for beneficial use, such as use as a fuel. Where a compressor is used to boost the recovered vapors into the line, this is often referred to as a VRU.¹⁸ Typically with a VRU, hydrocarbon vapors are drawn out of the storage vessel under low pressure and are piped to a separator, or suction scrubber, to collect any condensed liquids, which are usually recycled back to the storage vessel. Vapors from the separator flow through a compressor that provides the low-pressure suction for the VRU system where the recovered hydrocarbons can be transported to various places, including a sales line and/or for use onsite.

Types of VRUs include conventional VRUs and venturi ejector vapor recovery units (EVRUTM) or vapor jet systems.¹⁹ Decisions on the type of VRU to use are based on the applicability needs (e.g., an EVRUTM is recommended where there is a high-pressure gas compressor with excess capacity and a vapor jet VRU is suggested where there is produced water, less than 75 million cubic feet (MMcf)/day gas and discharge pressures below 40 pounds per square inch gauge (psig)). The reliability and integrity of the compressor and suction scrubber and integrity of the lines that connect the tank to the compressor will affect the effectiveness of the VRU system to collect and recycle vapors.²⁰

A conventional VRU is equipped with a control pilot to shut down the compressor and permit the back flow of vapors into the tank in order to prevent the creation of a vacuum in the top of a tank when liquid is withdrawn and the liquid level drops. Vapors are then either sent to the pipeline for sale or used as onsite fuel. Figure 4.1 presents a diagram of a conventional VRU installed on a single crude oil storage vessel (multiple tank installations are also common).²¹

¹⁸ American Petroleum Institute. Letter to Bruce Moore, SPPD/OAQPS/EPA from M. Todd, API. *Re: Oil and Natural Gas Sector Consolidated Rulemaking*. Docket ID No. EPA-HQ-OAR-2010-0505.

¹⁹ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Installing Vapor Recovery Units*. Natural Gas STAR Program. Source Reduction Training to Interstate Oil and Gas Compact Commission Presentation. February 27, 2009.

²⁰ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Installing Vapor Recovery Units on Storage Tanks*. Natural Gas STAR Program. October 2006.

²¹ Ibid.

Conventional VRU

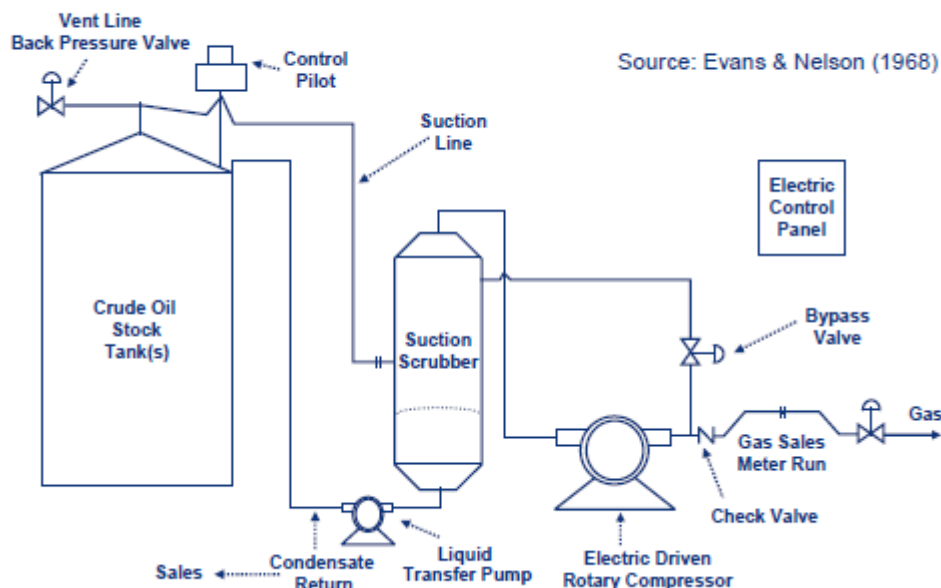


Figure 4-1. Conventional Vapor Recovery System

Control Effectiveness

Vapor recovery units have been shown to reduce VOC emissions from storage vessels by over 95 percent.²² When operating properly, VRUs generally approach 100 percent efficiency. We recognize that VRUs may not continuously meet this efficiency in practice. Therefore, our analysis assumes a 95 percent reduction in VOC emissions for a VRU. A VRU recovers hydrocarbon vapors that potentially can be used as supplemental burner fuel, or the vapors can be condensed and collected as condensate that can be sold. If natural gas is recovered, it can be sold as well, as long as a gathering line is available to convey the recovered salable gas product to market or to further processing. A VRU cannot be used in all instances. Conditions that affect the feasibility of the use of a VRU include: the availability of electrical service sufficient to power the compressor; fluctuations in vapor loading caused by surges in throughput and flash emissions from the storage vessel; potential for drawing air into condensate storage vessels causing an explosion hazard; and lack of appropriate destination or use for the vapor recovered.

²² Ibid.

Cost Impacts

Cost data for a VRU obtained from an initial economic impact analysis prepared for proposed state-only revisions to a Colorado regulation are presented here.²³ We assumed cost information contained in the Colorado economic impact analysis to be given in 2012 dollars. According to the Colorado economic impact analysis, the cost of a VRU was estimated to be \$90,000. Including costs associated with freight and design, and the cost of VRU installation, we estimated costs to be \$102,802 (\$90,000 plus \$12,802). We also added an estimated storage vessel retrofit cost of \$68,736 assuming that the cost of retrofitting an existing storage vessel was 75 percent of the purchased equipment cost (i.e., VRU capital cost and freight and design cost).²⁴ Based on these costs, we estimated the total capital investment of the VRU to be \$171,538. These cost data are presented in Table 4-3. We estimated total annual costs using 2012 dollars to be \$28,230 per year without recovered natural gas savings. The uncontrolled emissions from a storage vessel are largely dependent on the bbl/year throughput (see Table 4-2), which greatly influences both the controlled emissions and the cost of control per ton of VOC reduced. Costs may vary due to VRU design capacity, system configuration, and individual site needs and recovery opportunities.

In order to assess the cost of control of a VRU for uncontrolled storage vessels that emit differing emissions, we evaluated the cost of routing VOC emissions from an existing uncontrolled storage vessel to a VRU for a storage vessel that emits 2 tpy, 4 tpy, 6 tpy, 8 tpy, 10 tpy, 12 tpy, and 25 tpy. We estimated the cost of control without savings by dividing the total annual costs without savings by the tpy reduced assuming 95 percent control. The cost of control with savings is calculated by assuming a 95 percent reduction of VOC emissions by the VRU and converting the reduced VOC emissions to natural gas savings. Table 4-4 presents the estimated natural gas savings and the VOC cost per ton of VOC reduced with and without savings.

²³ Initial Economic Impact Analysis for Proposed Revisions to the Colorado Air Quality Control Commission Regulation Number 7, *Emissions of Volatile Organic Compounds*. November 15, 2013.

²⁴ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Installing Vapor Recovery Units on Storage Tanks*. Natural Gas STAR Program. October 2006.

Table 4-3. Total Capital Investment and Total Annual Costs of a Vapor Recovery Unit System

Cost Item ^a	Cost (\$2012)
Capital Cost Items	
VRU ^a	\$90,000
Freight and Design ^a	\$1,648
VRU Installation ^a	\$11,154
Storage Vessel Retrofit ^b	\$68,736
Total Capital Investment	\$171,538
Annual Cost Items	
Maintenance	\$9,396
Capital Recovery (7 percent interest, 15 year equipment life) (\$/yr)	\$18,834
Total Annual Costs w/o Savings (\$/yr)	\$28,230

^a Cost data from the Initial Economic Impact Analysis for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7, Submitted with Request for Hearing Documents on November 15, 2013.

^b Assumes the storage vessel retrofit cost is 75 percent of the purchased equipment price (assumed to include vent system and piping to route emissions to the control device). Retrofit assumption from Exhibit 6 of the EPA Natural Gas Star Lessons Learned, *Installing Vapor Recovery Units on Storage Tanks*. October 2006.

Table 4-4. Cost of Routing Emissions from an Existing Uncontrolled Storage Vessel to a VRU (\$/ton of VOC Reduced)

Uncontrolled Storage Vessel Emissions (tpy)	Cost per Ton of VOC Reduced (\$2012)		
	Without Savings	Natural Gas Savings (Mscf/yr) ^a	With Savings ^b
2	\$14,858	59	\$14,734
4	\$7,429	118	\$7,305
6	\$4,953	177	\$4,828
8	\$3,714	236	\$3,590
10	\$2,972	295	\$2,847
12	\$2,476	353	\$2,352
25	\$1,189	736	\$1,065

^a The natural gas savings was calculated by assuming 95 percent VOC recovery and 31 Mscf/yr natural gas savings per ton of VOC recovered.

^b Assumes a natural gas price of \$4.00 per Mcf.

Additionally, if a VRU is used to control VOC emissions from multiple storage vessels, the VOC emissions cost of control would be reduced because the cost for the additional storage vessel(s) would only include the storage vessel retrofit costs, and the overall VOC emission reductions would increase.

4.3.1.2 Routing Emissions to a Combustion Device

Description and Control Effectiveness

Combustors (e.g., enclosed combustion devices, thermal oxidizers and flares that use a high-temperature oxidation process) are also used to control emissions from storage vessels. Combustors are used to control VOC in many industrial settings, since the combustor can normally handle fluctuations in concentration, flow rate, heating value, and inert species content.²⁵ For this analysis, we assumed that the types of combustors installed in the oil and natural gas industry can achieve at least a 95 percent control efficiency on a continuing basis.²⁶ We note that combustion devices can be designed to meet 98 percent control efficiencies, and can control, on average, emissions by 98 percent or more in practice when properly operated.²⁷ We also recognize that combustion devices that are designed to meet a 98 percent control efficiency may not continuously meet this efficiency in practice, due to factors such as variability of field conditions.

A typical combustor used to control emissions from storage vessels in the oil and natural gas industry is an enclosed combustion system. The basic components of an enclosed combustion system include (1) piping for collecting emission source gases, (2) a single- or multiple-burner unit, (3) a stack enclosure, (4) a pilot flame to ignite the mixture of emission source gas and air and (5) combustor fuel/piping (as necessary). Figure 4-2 presents a schematic of a typical dual-burner enclosed combustion system.

²⁵ U.S. Environmental Protection Agency. AP 42, Fifth Edition, Volume I, *Chapter 13.5 Industrial Flares*. Office of Air Quality Planning & Standards. 1991.

²⁶ U.S. Environmental Protection Agency. *Air Pollution Control Technology Fact Sheet: FLARE*. Clean Air Technology Center.

²⁷ The EPA has currently reviewed performance tests submitted for 19 different makes/models of combustor control devices and confirmed that they meet the performance requirements in NSPS subpart OOOO and NESHAP subparts HH and HHH. All reported control efficiencies were above 99.9 percent at tested conditions. The EPA notes that the control efficiency achieved in the field is likely to be lower than the control efficiency achieved at a bench test site under controlled conditions, but we believe that these units should have no problem meeting 95 percent control continuously and 98 percent control on average when designed and properly operated to meet 98 percent control.

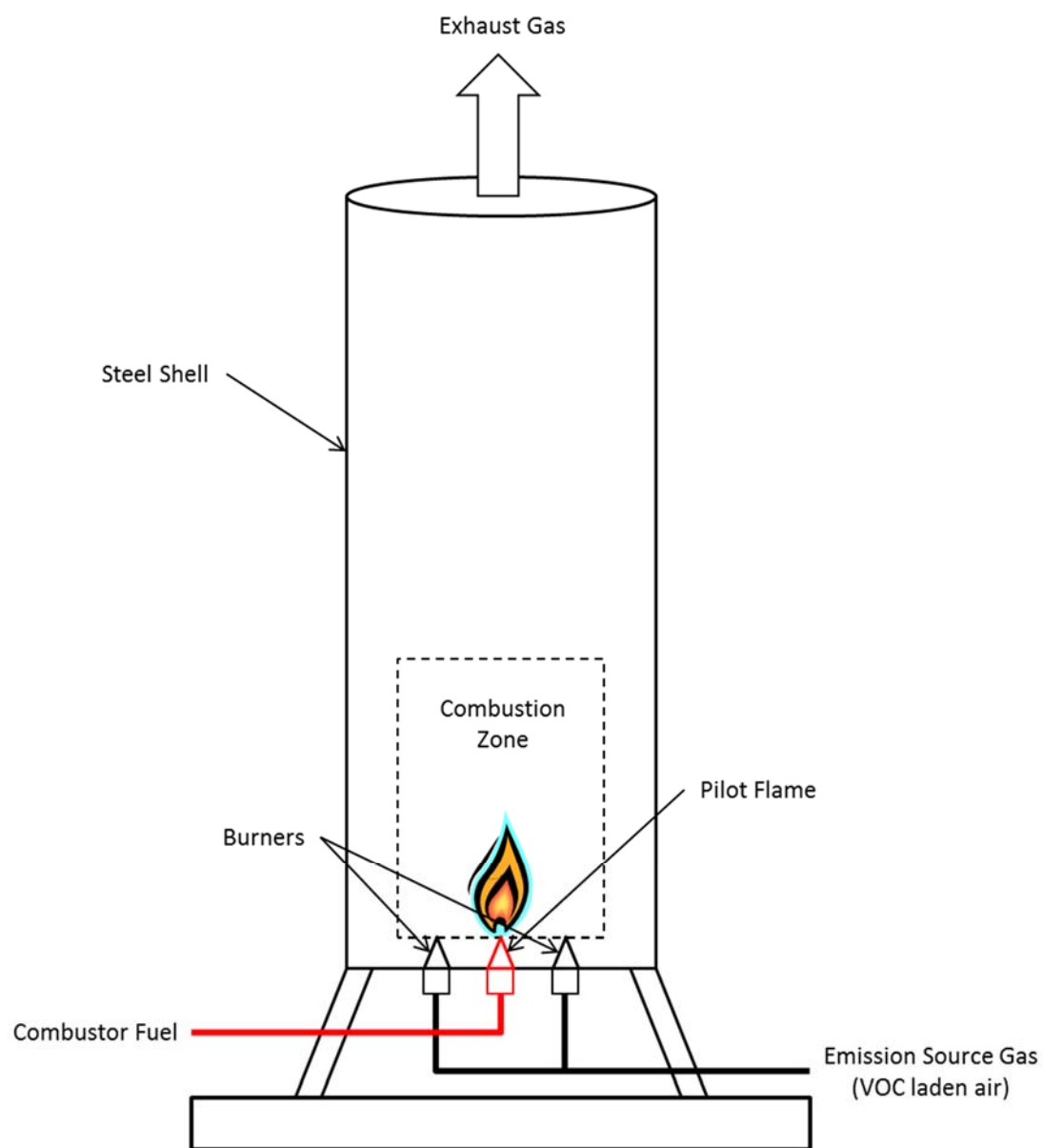


Figure 4-2. Schematic of a Typical Enclosed Combustion System

Thermal oxidizers, also referred to as direct flame incinerators, thermal incinerators, or afterburners, could also be used to control VOC emissions. Similar to a basic enclosed combustion device, a thermal oxidizer uses burner fuel to maintain a high temperature (typically 800-850°C) within a combustion chamber. The VOC laden emission source gas is injected into the combustion chamber where it is oxidized (burned), and then the combustion products are exhausted to the atmosphere. Figure 4-3 provides a basic schematic of a thermal oxidizer.²⁸

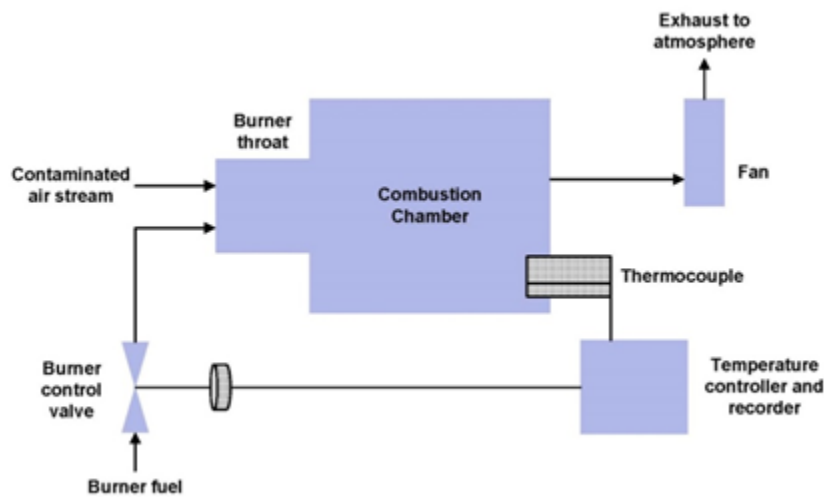


Figure 4-3. Basic Schematic of a Thermal Oxidizer

Cost Impacts

For combustion devices, we obtained cost data from the initial economic impact analysis prepared for state-only revisions to the Colorado regulation.²⁹ In addition to these cost data, we added line items for operating labor, a surveillance system and data management. This is consistent with the guidelines outlined in the EPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (OCCM) for combustion devices and the cost analysis prepared for the 2012 NSPS.^{30,31} However, OCCM guidelines specify 630 operating labor hours

²⁸ U.S. Environmental Protection Agency. Technology Transfer Network. Clearinghouse for Inventories and Emission Factors. *Thermal Oxidizer*. Website: <https://cfpub.epa.gov/oarweb/mkb/contechnique.cfm?ControllD=17>.

²⁹ Initial Economic Impact Analysis for Proposed Revisions to the Colorado Air Quality Control Commission Regulation Number 7, *Emissions of Volatile Organic Compounds*. November 15, 2013.

³⁰ *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standard for Hazardous Air Pollutants Reviews. Final Rule*. 77 FR 49490, August 16, 2012.

³¹ U.S. Environmental Protection Agency. *OAQPS Control Cost Manual: Sixth Edition* (EPA 452/B-02-001). Research Triangle Park, NC.

per year for a combustion device, which we believe is unreasonable because many of these sites are unmanned and would most likely be operated remotely. Therefore, we assumed that the operating labor would be more similar to that estimated for a condenser in the OCCM, 130 hours per year. We estimated a total capital investment of \$100,986 and total annual costs of \$25,194 per year. The total capital investment cost includes a storage vessel retrofit cost of \$68,736 (as discussed previously for VRUs) to accommodate the use of a combustion device. These cost data are presented in Table 4-5.

Table 4-5. Total Capital Investment and Total Annual Costs of a Combustor³²

Cost Item^a	Cost (\$2012)
<i>Capital Cost Items</i>	
Combustor ^a	\$18,169
Freight and Design ^a	\$1,648
Auto Ignitor ^a	\$1,648
Surveillance System ^{b,c,d}	\$3,805
Combustor Installation ^a	\$6,980
Storage Vessel Retrofit ^e	\$68,736
Total Capital Investment	\$100,986
<i>Annual Cost Items</i>	
Operating Labor ^f	\$5,155
Maintenance Labor ^f	\$4,160
Non-Labor Maintenance ^a	\$2,197
Pilot Fuel	\$1,537
Data Management ^c	\$1,057
Capital Recovery (7 percent interest, 15 year equipment life) (\$/yr)	\$11,088
Total Annual Cost (\$/yr)	\$25,194

^a Cost data from Initial Economic Impact Analysis for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7, Submitted with Request for Hearing Documents on November 15, 2013.

^b Surveillance system identifies when pilot is not lit and attempts to relight it, documents the duration of time when the pilot is not lit, and notifies and operator that repairs are necessary.

³² U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.

^c U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket ID No. EPA-HQ-OAR-2010-0505-4550.

^d Cost obtained from 2012 NSPS TSD and escalated using the change in GDP: Implicit Price Deflator from 2008 to 2012 (percent) (which was 5.69 percent). Source: FRED GDP: Implicit Price Deflator from Jan 2008 to Jan 2012 (<http://research.stlouisfed.org/fred2/series/GDPDEF/#>).

^e Retrofit cost obtained from Storage Vessel Retrofit in Table 4-3 (assumed to include vent system and piping to route emissions to the control device).

^f Operating labor consists of labor resources for technical operation of device (130 hr/yr) and supervisory labor (15 percent of technical labor hours). Maintenance labor hours are assumed to be the same as operating labor (130 hr/yr). Labor rates are \$32.00/hr (for technical and maintenance labor) and \$51.03 (supervisory labor) and were obtained from the U.S. Department of Labor, Bureau of Labor Statistics, Employer Costs for Employee Compensation, December 2012. Labor rates account for total compensation (wages/salaries, insurance, paid leave, retirement and savings, supplemental pay and legally required benefits).

As noted previously, storage vessels vary in size and throughputs and the uncontrolled emissions from a storage vessel are largely dependent on the bbl/year throughput (see Table 4-2), which greatly influences both the controlled emissions and cost of control. In order to assess the cost of control of combustion for uncontrolled storage vessels that emit differing emissions, we evaluated the costs of routing VOC emissions from an existing storage vessel to a combustion device for an existing uncontrolled storage vessel that emits 2 tpy, 4 tpy, 6 tpy, 8 tpy, 10 tpy, 12 tpy and 25 tpy. We estimated the cost of control without savings by dividing the total annual costs without savings by the tpy reduced assuming 95 percent control. Table 4-6 presents these costs. The VOC emissions cost of control per ton of VOC reduced would be less if a combustion device is used to control uncontrolled VOC emissions from multiple storage vessels because the cost for the additional storage vessel(s) would only include storage vessel retrofit costs, and the overall VOC emission reductions would increase.

Table 4-6. Cost of Routing Emissions from an Existing Uncontrolled Storage Vessel to a Combustion Device (\$/ton of VOC Reduced)

Uncontrolled Storage Vessel Emissions (tpy)	Cost per Ton of VOC Reduced (\$2012)
2	\$13,260
4	\$6,630
6	\$4,420
8	\$3,315

Uncontrolled Storage Vessel Emissions (tpy)	Cost per Ton of VOC Reduced (\$2012)
10	\$2,652
12	\$2,411
25	\$2,210

4.3.1.3 *Routing Emissions to a VRU with a Combustion Device as Backup*

Industry practice also includes the primary operation of a VRU and secondary operation of a combustion device during VRU maintenance and other times requiring VRU downtime. Using the costs for a VRU and combustion device presented in sections 4.3.1.1 and 4.3.1.2, and assuming the VRU is operated 95 percent of the year and a combustion device is operated 5 percent of the year, we estimated total annual costs using 2012 dollars to be \$32,006 per year without recovered natural gas savings. As stated previously, the uncontrolled emissions from a storage vessel are largely dependent on the bbl/year throughput (see Table 4-2), which greatly influences both the controlled emissions and the cost of control per ton of VOC reduced. Costs may vary due to VRU design capacity, system configuration, and individual site needs and recovery opportunities, as well as the percent of time that a VRU is down during the year where emissions are routed to a combustion device. In order to assess the cost of control of a VRU with the use of a combustion device during downtime for uncontrolled storage vessels that emit differing emissions, we evaluated the costs of routing VOC emissions from an existing storage vessel to a VRU/combustion device for an existing uncontrolled storage vessel that emits 2 tpy, 4 tpy, 6 tpy, 8 tpy, 10 tpy, 12 tpy and 25 tpy. We estimated the cost of control without savings by dividing the total annual costs without savings by the tpy reduced assuming 95 percent control. The cost of control with savings is calculated by assuming a 95 percent reduction of VOC emissions by the VRU (used 95 percent of the year) and converting the reduced VOC emissions to natural gas savings. Table 4-7 presents these costs. The VOC emissions cost of control per ton of VOC reduced would be less if a VRU/combustion device is used to control uncontrolled VOC emissions from multiple storage vessels because the cost for the additional storage vessel(s) would only include storage vessel retrofit costs, and the overall VOC emission reductions would increase.

Table 4-7. Cost of Routing Emissions from an Existing Uncontrolled Storage Vessel to a VRU/Combustion Device (\$/ton of VOC Reduced)

Uncontrolled Storage Vessel Emissions (tpy)	Cost per Ton of VOC Reduced (\$2012)		
	Without Savings	Natural Gas Savings (Mscf/yr) ^a	With Savings ^b
2	\$16,845	56	\$16,728
4	\$8,423	112	\$8,305
6	\$5,615	168	\$5,497
8	\$4,211	224	\$4,094
10	\$3,369	280	\$3,251
12	\$2,808	336	\$2,690
25	\$1,348	699	\$1,230

^a The natural gas savings was calculated by assuming 95 percent VOC recovery and 31 Mscf/yr natural gas savings per ton of VOC recovered.

^b Assumes a natural gas price of \$4.00 per Mcf.

4.3.2 Existing Federal, State and Local Regulations

4.3.2.1 Federal Regulations that Specifically Require Control of VOC Emissions

Under the 2012 NSPS and 2013 NSPS Reconsideration, new or modified storage vessels with PTE VOC emissions of 6 tpy or more must reduce VOC emissions by at least 95 percent, or demonstrate emissions from a storage vessel have dropped to less than 4 tpy of VOC without emission controls for 12 consecutive months.

4.3.2.2 State and Local Regulations that Specifically Require Control of VOC Emissions³³

States may have permitting restrictions on VOC emissions that may apply to an emissions source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met, and how the source must be operated. To ensure that sources

³³ Brown, Heather, EC/R Incorporated. Memorandum prepared for Bruce Moore, EPA/OAQPS/SPPD/FIG. *Revised Analysis to Determine the Number of Storage Vessels Projected to be Subject to New Source Performance Standards for the Oil and Natural Gas Sector*. 2013.

follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

The environmental regulations in nine of the top oil and natural gas producing states (sometimes with varying local ozone nonattainment area/concentrated area development requirements) (see Table 4-8) require the control of VOC emissions from storage vessels in the oil and natural gas industry. These states include California, Colorado, Kansas, Louisiana, Montana, North Dakota, Oklahoma, Texas, and Wyoming. All except Wyoming require 95 percent emission control with the application of a VRU or combustion (Wyoming requires 98 percent control of emissions using a VRU or combustion).

Existing state regulations that apply to storage vessels in the oil and natural gas industry apply to all storage vessels in a tank battery, or include an applicability threshold based on (1) capacity, (2) the vapor pressure of liquids contained in a storage vessel of a specified capacity, and (3) the PTE of an individual storage vessel. Table 4-8 presents a brief summary of the storage vessel emission control applicability cutoffs in regulations from these nine states. Four states (Colorado, Montana, Texas, and Wyoming) have applicability thresholds in terms of VOC emissions. The remaining five states have storage vessel regulations that are in terms of tank characteristics, such as vapor pressure, tank size, or tank contents. Equivalency of applicability thresholds based on tank and stored liquid characteristics and applicability thresholds based on VOC emissions cannot be determined. We analyzed the varying state VOC emission thresholds (based on a range of 2 tpy to 25 tpy) as part of our cost of control analysis for VRUs and combustion devices in section 4.3.1 of this chapter.

Table 4-8. Summary of Storage Vessel Applicability Thresholds from Nine States

State/Local Authority	Applicability Threshold
Texas	Applies to storage vessels with VOC emissions greater than 25 tpy.
California Bay Area AQMD	Applies to storage vessels with capacity greater than 264 gallons.
California Feather River AQMD	Applies to storage vessels with capacity greater than 39,630 gallons.
California Monterey Bay Unified APCD	Applies to storage vessels with capacity greater than 39,630 gallons.

State/Local Authority	Applicability Threshold
California Sacramento Metropolitan AQMD	Applies to storage vessels with capacity greater than 40,000 gallons.
California San Joaquin Valley Unified APCD	Applies to storage vessels with capacity greater than 1,100 gallons.
California Santa Barbara County APCD	Applies to all storage vessels in tank battery (including wash tanks, produced water tanks, and wastewater tanks).
California South Coast AQMD	Applies to storage vessels with capacity greater than 39,630 gallons with a true vapor pressure of 0.5 psia or greater and storage vessels with a capacity greater than 19,815 gallons with a true vapor pressure of 1.5 psia or greater.
California Ventura County APCD	Applies to all storage vessels. Requirements depend on gallon capacity and true vapor pressure of material contained in vessel.
California Yolo-Solano AQMD	Applies to storage vessels with capacity greater than 40,000 gallons.
North Dakota	NDAC 33-15-07: submerged filling requirements to control VOC for tanks >1,000 gallons.
Federal Implementation Plan (FIP): Fort Berthold Indian Reservation	Applies to all storage vessels (except those covered by NSPS subpart OOOO). There is no minimum threshold under the final FIP.
Louisiana	Applies to storage vessels more than 250 gallons up to 40,000 gallons with a maximum true vapor pressure of 1.5 psia or greater.
Oklahoma	Applies to storage vessels with capacity greater than 40,000 gallons (in ozone nonattainment areas).
Wyoming – Statewide	Applies to storage vessels with greater than or equal to 10 tpy VOC within 60 days of startup/modification.
Wyoming – Concentrated Development Area	Applies to storage vessels with greater than or equal to 8 tpy VOC within 60 days of startup/modification.
Kansas	Permanent fixed roof storage tanks >40,000 gallons and external floating roof storage tanks.
Colorado	Condensate tanks with uncontrolled VOC emissions > 20 tpy (2 tpy located at gas processing plants in ozone non-attainment areas).

State/Local Authority	Applicability Threshold
Montana	Applies to oil or condensate storage tanks with a PTE greater than 15 tpy VOC.

4.4 Recommended RACT Level of Control

As discussed in section 4.3.2 of this chapter, existing federal and state and local regulations already require the reduction of VOC emissions from storage vessels in the oil and natural gas industry at or greater than 95 percent. Further, we note that combustion devices can be designed to meet 98 percent control efficiencies and can control, on average, emissions by 98 percent or more in practice when properly operated.³⁴ We also recognize that combustion devices designed to meet 98 percent control efficiency may not continuously meet this efficiency in practice, due to factors such as the variability of field conditions. Therefore, the recommendations specify that devices should be required to continuously meet at least 95 percent VOC control efficiency. In light of the above considerations, a continuous 95 percent reduction of VOC emissions from storage vessels in the oil and natural gas industry is a reasonable recommended RACT level of control.

Although sources may have a choice on how they meet the recommended RACT level of control, if air agencies choose to adopt the recommended RACT contained in this CTG, the technologies that may be used to meet the recommended RACT level of control for oil and natural gas industry storage vessels are capturing and routing emissions to the process via a VRU and/or routing emissions to a combustion device.

As discussed in section 4.2.2 of this chapter, the VOC emissions from storage vessels vary significantly, depending on the rate of liquid entering and passing through the vessel (i.e., its throughput), the pressure of the liquid as it enters the atmospheric pressure storage vessel, the liquid's volatility, and temperature of the liquid. Some storage vessels have negligible emissions, such as those with very little throughput and/or handling heavy liquids entering at atmospheric

³⁴ The EPA has currently reviewed performance tests submitted for 19 different makes/models of combustor control devices and confirmed they meet the performance requirements in NSPS subpart OOOO and NESHAP subparts HH and HHH. All reported control efficiencies were above 99.9 percent at tested conditions. EPA notes that the control efficiency achieved in the field is likely to be lower than the control efficiency achieved at a bench test site under controlled conditions, but we believe that these units should have no problem meeting 95 percent control continuously and 98 percent control on average when designed and properly operated to meet 98 percent control.

pressure where it would not be cost-effective to require emission control requirements. Existing state regulations that apply to storage vessels in the oil and natural gas industry apply to all storage vessels in a tank battery, or include an applicability threshold based on (1) capacity, (2) the vapor pressure of liquids contained in a storage vessel of a specified capacity, and (3) the PTE of an individual storage vessel. Based on information gathered under the 2012 NSPS,³⁵ throughput and capacity of a storage vessel is not always the best indicator of a storage vessel's emissions, and we believe that the PTE of an individual storage vessel is preferable to use as an applicability threshold for storage vessels.

Based on our analyses conducted in support of the 2012 NSPS, 6 tpy was determined to be the applicability threshold for requiring 95 percent control of VOC emissions from new storage vessels (estimated to cost, on average, approximately \$3,400 per ton of VOC reduced). Our analyses conducted for our RACT recommendation also found 6 tpy to be the applicability threshold for requiring 95 percent control of VOC emissions from existing storage vessels (estimated to cost, on average, between \$4,400 and \$5,000 per ton of VOC reduced). Based on these analyses, we recommend that the 95 percent VOC emission control of storage vessels only apply to storage vessels that have a PTE greater than or equal to 6 tpy of VOC emissions. The VOC cost of control per ton of VOC reduced would be less if a combustion device or VRU is used to control VOC emissions from multiple storage vessels because the cost for the additional storage vessels would only include storage vessel retrofit costs, and the overall VOC emission reductions would increase.

We recommend an alternative RACT level of control for storage vessels that have a PTE VOC at or greater than 6 tpy that have actual emissions less than that on a continuing basis. For these storage vessels, if it can be demonstrated that the storage vessel has actual emissions less than 4 tpy for 12 consecutive months, we recommend that they be allowed to maintain and show continued compliance that their emissions are below 4 tpy in lieu of requiring 95 percent control. This alternative recommendation acknowledges that there are storage vessels that have a PTE greater than or equal to 6 tpy whose actual emissions have declined over time, usually because of declining production. This alternative RACT recommendation is informed by the 2012 NSPS, where we concluded that, based on “the cost-effectiveness, the secondary environmental impacts

³⁵ 77 FR 49490, August 16, 2012.

and the energy impacts...BSER for reducing VOC emissions from storage vessel affected facilities is not represented by continued control when their sustained (i.e., for 12 consecutive months) uncontrolled emission rates fall below 4 tpy.”³⁶

In summary, we recommend the following as RACT for storage vessels in the oil and natural gas industry:

- (1) RACT for Condensate Storage Vessels: Reduce emissions by 95 percent continuously from condensate storage vessels with a PTE $\geq$ 6 tpy of VOC; or demonstrate (based on 12 consecutive months of uncontrolled actual emissions) and maintain uncontrolled actual VOC emissions from storage vessels with a PTE greater than or equal to 6 tpy at less than 4 tpy.³⁷
- (2) RACT for Crude Oil Storage Vessels: Reduce emissions by 95 percent continuously from crude oil storage vessels with a PTE $\geq$ 6 tpy of VOC; or demonstrate (based on 12 consecutive months of uncontrolled actual emissions) and maintain uncontrolled actual VOC emissions from storage vessels with a PTE greater than or equal to 6 tpy at less than 4 tpy.³⁸

4.5 Factors to Consider in Developing Storage Vessel Compliance Procedures

4.5.1 Compliance Recommendations When Using a Control Device

Improper design or operation of the storage vessel and its control system can result in occurrences where peak flow overwhelms the storage vessel and its capture systems, resulting in emissions that do not reach the control device, effectively reducing the control efficiency. We believe that it is essential that operators employ properly designed, sized, and operated storage vessels to achieve effective emission control. We believe that such efforts on the part of owners and operators can result in more effective control of VOC emissions from storage vessels.

In order to ensure that VOC emissions are reduced by at least 95 percent (the recommended RACT level of control) from a storage vessel when using a control device or other

³⁶ Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards Final Amendments. Federal Register Notice. (78 FR 58429, September 23, 2013).

³⁷ We recommend that, prior to allowing the use of the uncontrolled 4 tpy actual VOC emissions rate for compliance purposes, air agencies require sources demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy for 12 consecutive months. After such demonstration, we recommend that air agencies require that sources demonstrate continued compliance with the uncontrolled actual VOC emission rate each month.

³⁸ See footnote 37.

control measure (such as routing to a process), the storage vessel should be equipped with a cover that is connected through a closed vent system that captures and routes emissions to the control device (or process). We recommend cover, closed vent system and control device design and compliance measures to ensure that control measures meet the RACT level of control. Recommended cover and closed vent system design and operation measures are specified in sections 4.5.1.1 and 4.5.1.2. Recommended control device operation and monitoring provisions for specified controls to ensure compliance are presented in sections 4.5.1.3 and 4.5.1.4. The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part.

4.5.1.1 *Recommendations for Cover Design*

The cover and all openings on the cover (e.g., access hatches, sampling ports, pressure relief valves, and gauge wells) should form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel. Each cover opening should be secured in a closed, sealed position (gasket lid or cap) whenever material is in the unit except when it is necessary to open as follows:

- (1) To add material to or remove material from the unit (including openings necessary to equalize or balance the internal pressure of the unit following changes in the level of material in the unit);
- (2) To inspect or sample the material in the unit;
- (3) To inspect, maintain, repair, or replace equipment located in the unit; or
- (4) To vent liquids, gases or fumes from the unit through a closed vent system designed and operated in accordance with specified closed vent system requirements (see section 4.5.1.2) or to a process.

It is recommended that air agencies require the storage vessel thief hatch be equipped, maintained and operated with a weight, or other mechanism, to ensure that the lid remains properly seated. It is recommended that air agencies require the gasket material for the hatch be selected based on composition of the fluid in the storage vessel and weather conditions.

It is also recommended that air agencies require monthly olfactory, visual and auditory inspections of covers for defects that could result in air emissions. Any detected defects should be required to be repaired as soon as practicable.

4.5.1.2 *Recommendations for Closed Vent Systems*

The closed vent system should be designed and operated with no detectable emissions (which can be monitored by monthly olfactory, visual and auditory inspections). It is recommended that air agencies require that any detected defects be repaired as soon as practicable.

With the exception of low leg drains, high point bleeds, analyzer vent, open-ended valves and safety devices, if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process, it is recommended that air agencies require owners and operators either:

(1) Install, calibrate, maintain and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere; or

(2) Secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

4.5.1.3 *Recommendations When “Routing to a Process” or to a VRU*

Routing to a process would entail routing emissions via a closed vent system to any enclosed portion of a process unit where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product and/or recovered. Vapor recovery units and flow lines that “route emissions to a process” would be considered part of the process and would not be considered control devices that are subject to standards, but the recommended cover and closed vent system design, operation and monitoring requirements specified in sections 4.5.1.1 and 4.5.1.2 would apply.

4.5.1.4 *Recommendations for Control Device Operation and Monitoring*

If a control device is used to comply with the recommended 95 percent VOC emission reduction RACT level of control, it is recommended that air agencies require that the device

operate at all times when gases, vapors, and fumes are vented from the storage vessel subject to VOC emission requirements through the closed vent system to the control device.

For control devices used to meet the recommended RACT, it is recommended that air agencies require owners and operators follow the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

If an owner or operator complies with the recommended RACT by using a combustion device, it is recommended that air agencies require initial and periodic performance testing (no later than 60 months after the initial performance test) to demonstrate initial and continued compliance with the recommended RACT level of control. Additionally, for each combustion device used to comply with the recommended continuous 95 percent VOC emission reduction, it is recommended that air agencies require owners and operators conduct the following control device compliance assurance measures: (1) Monthly visual inspections or monitoring to confirm that the pilot is lit when vapors are routed to it. (2) Monthly inspections to monitor for visible emissions from the combustion device using section 11 of EPA Method 22 of appendix A of part 60. It is recommended that the observation period be 15 minutes and that devices be operated with no visible emissions, except for periods not to exceed a total of one minute during any 15-minute period. (3) Monthly olfactory, visual and auditory inspections associated with the combustion device to ensure system integrity.

4.5.2 Compliance Recommendations When Complying with the 4 tpy VOC Emissions Alternative Limitation

If the alternative RACT recommendation to determine and maintain the uncontrolled actual VOC emissions from a storage vessel that has a PTE to emit greater than or equal to 6 tpy at less than 4 tpy without considering control is used, it is recommended that air agencies first require that a source demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, it is recommended that air agencies require that the source determine the uncontrolled actual VOC emission rate each month using a generally accepted model or calculation methodology. It is also recommended that such calculations be based on the average throughput for the month. If the monthly emissions determination indicates that VOC emissions from a storage vessel subject to VOC emission control requirements increases to 4 tpy or greater and the increase is not

associated with fracturing or refracturing of a well feeding the storage vessel, it is recommended that air agencies require that the source comply with the 95 percent VOC emission reduction RACT level of control recommendation or that emissions be routed to a VRU.

5.0 COMPRESSORS

Compressors are mechanical devices that increase the pressure of natural gas and allow the natural gas to be transported from the production site, through the supply chain, and to the consumer. The types of compressors that are used by the oil and natural gas industry as prime movers are reciprocating and centrifugal compressors. This chapter discusses the sources of VOC emissions from these compressors. This chapter also provides control techniques used to reduce VOC emissions from these compressors, along with costs and emission reductions. Finally, this chapter provides a discussion of our recommended RACT and the associated VOC emission reductions and costs for both reciprocating and centrifugal compressors.

5.1 Applicability

For the purposes of this CTG, the emissions and emission reductions discussed herein would apply to centrifugal and reciprocating compressors in the oil and natural gas industry located between the wellhead and point of custody transfer to the natural gas transmission and storage segment. As noted in section 3.2 of this document, we did not evaluate RACT for compressors located at a well site, or an adjacent well site and servicing more than one well site.

5.2 Process Description and Emission Sources

5.2.1 Process Description

5.2.1.1 *Reciprocating Compressors*

In a reciprocating compressor, natural gas enters the suction manifold, and then flows into a compression cylinder where it is compressed by a piston driven in a reciprocating motion by the crankshaft powered by an internal combustion engine. Emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. The compressor rod packing system consists of a series of flexible rings that create a seal around the piston rod to prevent gas from escaping between the rod and the inboard cylinder head. However, over time, during operation of the compressor, the rings become worn and the packaging system needs to be

replaced to prevent excessive leaking from the compression cylinder. See Figure 5-1 for a depiction of a typical rod compressor packing system configuration.³⁹

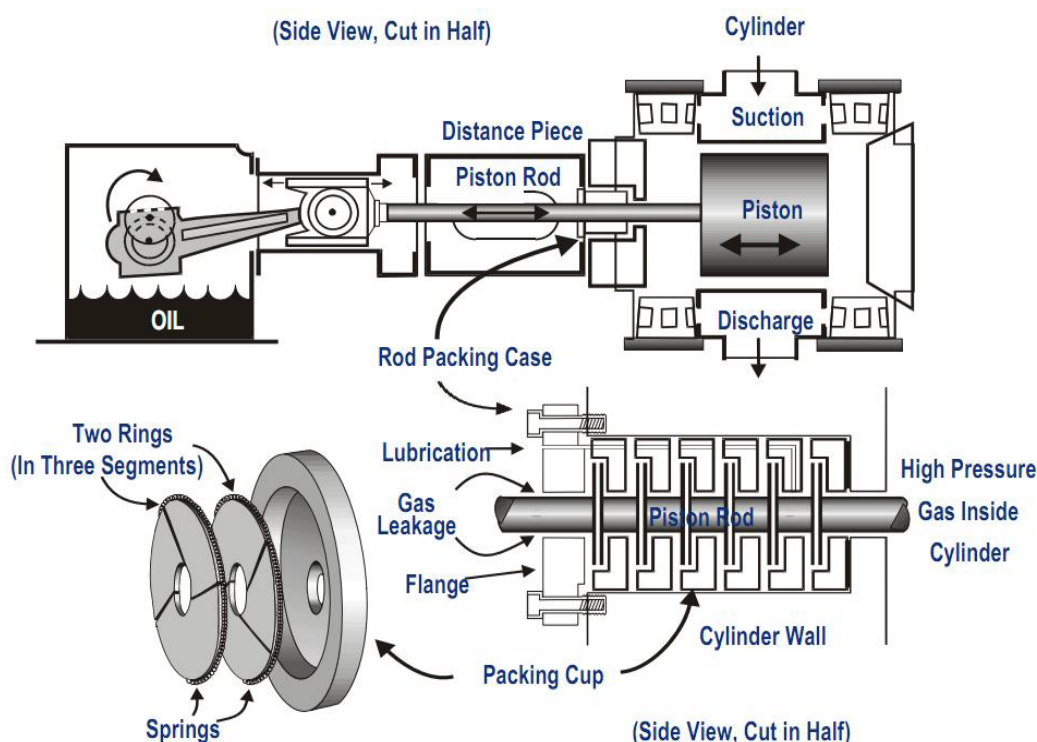


Figure 5-1. Typical Reciprocating Compressor Rod Packing System Diagram

5.2.1.2 Centrifugal Compressors

Centrifugal compressors use a rotating disk or impeller to increase the velocity of the natural gas where it is directed to a divergent duct section that converts the velocity energy to pressure energy. These compressors are primarily used for continuous, stationary transport of natural gas in the processing and transmission systems. Many centrifugal compressors use wet (meaning oil) seals around the rotating shaft to prevent natural gas from escaping where the compressor shaft exits the compressor casing. The wet seals use oil which is circulated at high pressure to form a barrier against compressed natural gas leakage. The circulated oil entrains and

³⁹ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR Program. 2006.

adsorbs some compressed natural gas that may be released to the atmosphere during the seal oil recirculation process. Figure 5-2 illustrates the wet seal compressor configuration.⁴⁰

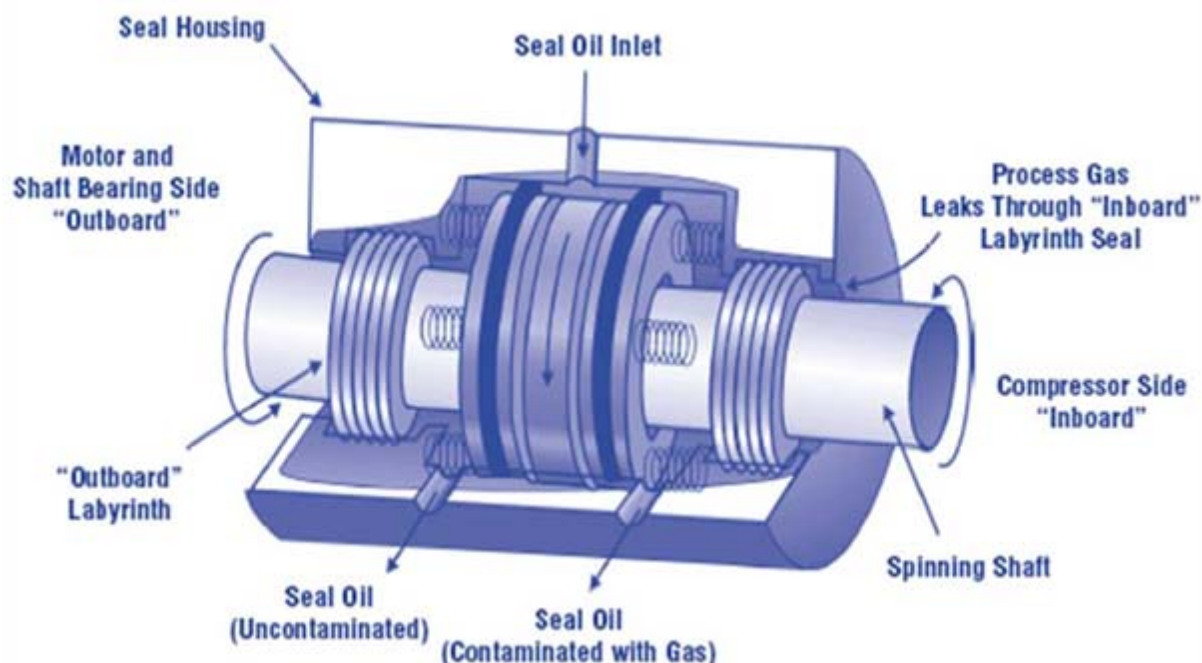


Figure 5-2. Typical Centrifugal Compressor Wet Seal

Alternatively, dry seals can be used in place of wet seals in centrifugal compressors. Dry seals prevent leakage by using the opposing force created by hydrodynamic grooves and springs (see Figure 5-3). The hydrodynamic grooves are etched into the surface of the rotating ring affixed to the compressor shaft. When the compressor is not rotating, the stationary ring in the seal housing is pressed against the rotating ring by springs. When the compressor shaft rotates at high speed, compressed natural gas has only one pathway to leak down the shaft, and that is between the rotating and stationary rings. This natural gas is pumped between the grooves in the rotating and stationary rings. The opposing force of high-pressure natural gas pumped between the rings and springs trying to push the rings together creates a very thin gap between the rings through which little natural gas can leak. While the compressor is operating, the rings are not in

⁴⁰ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Replacing Wet Seals with Dry Seals in Centrifugal Compressors*. Natural Gas STAR Program. October 2006.

contact with each other and, therefore, do not wear or need lubrication. O-rings seal the stationary rings in the seal case.⁴¹

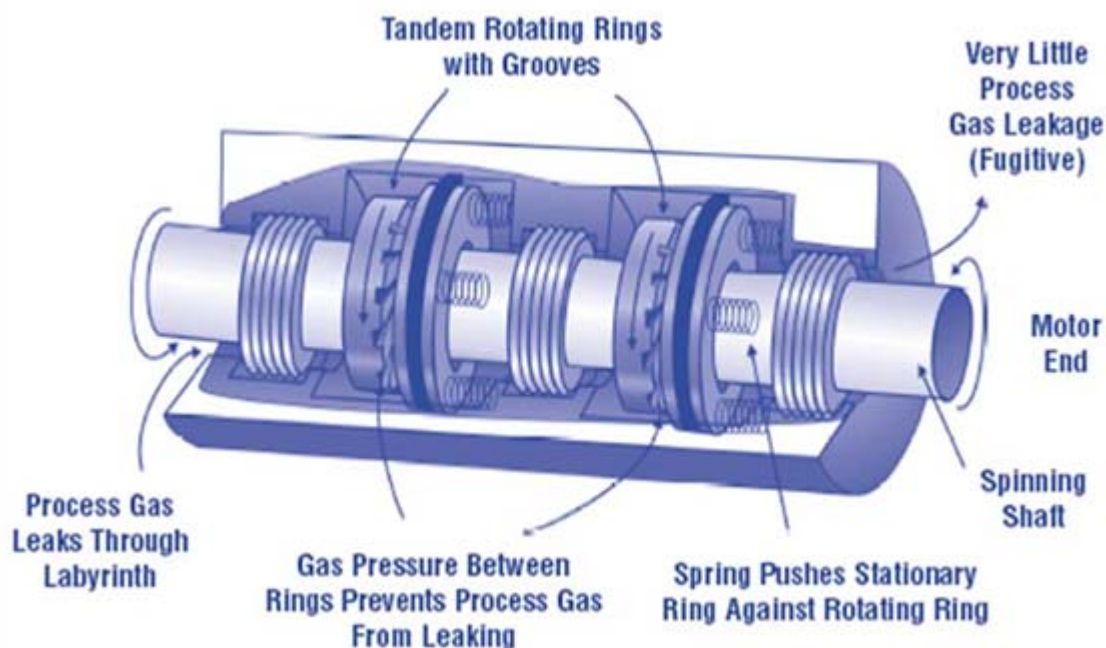


Figure 5-3. Typical Centrifugal Compressor Tandem Dry Seal

Natural gas emissions from wet seal centrifugal compressors have been found to be higher than dry seal compressors primarily due to the off-gassing of the entrained natural gas from the oil. This natural gas is not suitable for sale and is either released to the atmosphere, flared, or routed back to a process. In addition to lower natural gas leakage (and therefore lower emissions), dry seals have been found to have lower operation and maintenance costs than wet seal compressors because they are a mechanically simpler design, require less power to operate, and are more reliable. For the same reasons we explained in the 2012 NSPS and the 2015 NSPS proposal, we are not recommending RACT for dry seal compressors and instead include the use of a dry seal in place of a wet seal system as an available control option for reducing VOC emissions from wet seal centrifugal compressors (discussed in section 5.3.1.2 of this chapter). During the rulemakings for the 2012 NSPS and 2016 NSPS, we found that the dry seal system and the option of routing to a process both had at least a 95 percent control efficiency.

⁴¹ Ibid.

5.2.2 Emissions Data

5.2.2.1 Summary of Major Studies and Emissions

Several studies have been conducted that provide leak estimates from reciprocating and centrifugal compressors. Table 5-1 lists these studies, along with the type of information contained in the study. In addition to these sources, we evaluated the peer reviewer and public comments received on the EPA’s white paper, “Oil and Natural Gas Sector Compressors.”⁴²

Table 5-1. Major Studies Reviewed for Emissions Data⁴³

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options ^j
Inventory of Greenhouse Gas Emissions and Sinks ^a	EPA	Annual	Nationwide	X	
Greenhouse Gas Reporting Program (Annual Reporting; Current Data Available for 2011-2013) ^b	EPA	2014	Facility-Level	X	X
Methane Emissions from the Natural Gas Industry ^c	EPA/Gas Research Institute (GRI)	1996	Nationwide	X	
Natural Gas STAR Program ^{d,e}	EPA	1993-2010	Nationwide	X	X
Natural Gas Industry Methane Emission Factor Improvement Study ^f	URS Corporation, UT Austin, and EPA	2011	None	Emission Factors Only	
Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production: Summary and Analysis of API and ANGA Survey Responses ^g	API/ANGA	2012	Regional	X ^h	
Economic Analysis of Methane Emissions Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries ⁱ	ICF International (Prepared for the Environmental Defense Fund (EDF))	2014	Regional	X	X

⁴² U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Compressors. Report for Oil and Natural Gas Sector Compressors Review Panel*. Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at <http://www.epa.gov/airquality/oilandgas/2014papers/20140415compressors.pdf>.

⁴³ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.

^a U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. <https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html>.

^b U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC. November 2014.

^c U.S. Environmental Protection Agency/GRI. National Risk Management Research Laboratory. Research and Development. *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*. Prepared for the U.S. Department of Energy, Energy Information Administration. EPA-600/R-96-080h. June 1996.

^d U.S. Environmental Protection Agency. *Lessons Learned: Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR. Environmental Protection Agency. 2006.

^e U.S. Environmental Protection Agency. *Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors*. Natural Gas STAR. Environmental Protection Agency. October 2006.

^f URS Corporation/University of Texas at Austin. 2011. *Natural Gas Industry Methane Emission Factor Improvement Study, Final Report*. December 2011. http://www.utexas.edu/research/ceer/GHG/files/FReports/XA_83376101_Final_Report.pdf.

^g American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA). *Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production. Summary and Analysis of API and ANGA Survey Responses*. Final Report. September 21, 2012.

^h The API/ANGA study provided information on equipment counts that could augment nationwide emissions calculations. No source emission information was included.

ⁱ ICF International. *Economic Analysis of Methane Emissions Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries*. Prepared for the Environmental Defense Fund. March 2014.

^j An "X" in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

5.2.2.2 Representative Reciprocating and Centrifugal Compressor Emissions

The centrifugal compressor methane emission factors used for processing are based on emission factor data for wet seals and dry seals from a sampling of wet seal and dry seal centrifugal compressor data that was used to calculate emissions in the GHG Inventory.

For gathering and boosting station reciprocating compressors, the 2011 NSPS TSD emission factors were used because they are considered to be the best representative emission factors at this time. Emission factors in the Clearstone study,⁴⁴ which are expressed in thousand standard cubic feet per cylinder, were multiplied by the average number of cylinders per gathering and boosting station reciprocating compressor. The volumetric methane emission rate was converted to a mass emission rate using a density of 41.63 pounds of methane per thousand cubic feet. This conversion factor was developed assuming that methane is an ideal gas and using the ideal gas law to calculate the density. A summary of the reciprocating compressor methane

⁴⁴ Clearstone Engineering Ltd. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*. 2006.

emission factors used for this analysis is presented in Table 5-2. Once the mass methane emission rate was calculated, ratios were used to estimate VOC emissions using the methane to VOC pollutant ratios developed in the 2011 Gas Composition Memorandum. The specific ratio that was used to convert methane emissions to VOC emissions is 0.278 pounds VOC per pound of methane for the production and processing segments. Table 5-3 presents a summary of the estimated methane and VOC emissions per reciprocating and centrifugal compressor (in tpy) for the production and processing segments.

Table 5-2. Methane Emission Factors for Reciprocating and Centrifugal Compressors⁴⁵

Oil and Gas Industry Segment	Reciprocating Compressors			Centrifugal Compressors	
	Methane Emission Factor (scfh-cylinder)	Average Number of Cylinders	Pressurized Factor (Percent of Hours/Year Compressor Pressurized)	Wet Seal Methane Emission Factor (scfm)	Dry Seal Methane Emission Factor (scfm)
Gathering & Boosting Stations	25.9 ^a	3.3	79.1%	N/A ^c	N/A ^c
Processing	57 ^b	2.5	89.7%	47.7 ^d	6 ^d

^a Clearstone Engineering Ltd. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*. 2006.

^b U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks*. Table 4-14.

^c U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry: Volume 11 – Compressor Driver Exhaust*. 1996 Report does not report any centrifugal compressors in the production or gathering/boosting segments, therefore no emission factor data were published for those two segments.

^d U.S. Environmental Protection Agency. *Methodology for Estimating CH₄ and CO₂ Emissions from Petroleum Systems. Greenhouse Gas Inventory: Emission and Sinks 1990-2012*. Washington, DC. April 2014.

⁴⁵ U.S. Environmental Protection Agency/GRI. Research and Development, National Risk Management Research Laboratory. *Methane Emissions from the Natural Gas Industry*. Prepared for the U.S. Department of Energy, Energy Information Administration. EPA-600/R-96-080h. June 1996.

Table 5-3. Baseline VOC Emission Estimates for Reciprocating and Centrifugal Compressors^a

Industry Segment/Compressor Type	Baseline Emission Estimates (tpy)	
	Methane	VOC
Reciprocating Compressors		
Gathering and Boosting Stations	12.3	3.42
Processing	22	6.12
Centrifugal Compressors (Wet seals)		
Processing	210.53	19.1
Centrifugal Compressors (Dry seals)		
Processing	26	2.4

^a For centrifugal compressors, it was assumed that 75 percent of the natural gas that is compressed is pipeline quality gas and 25 percent of the natural gas is production quality.

5.3 Available Controls and Regulatory Approaches

5.3.1 Available VOC Emission Control Options

Available controls for reducing VOC emissions from reciprocating and centrifugal compressors are presented in sections 5.3.1.1 and 5.3.1.2 of this chapter.

5.3.1.1 *Reciprocating Compressors*

Potential control options for reducing emissions from reciprocating compressors include control techniques that limit the leaking of natural gas past the piston rod packing. These options include: (1) increasing or specifying the frequency of the replacement of the compressor rod packing, (2) increasing or specifying the frequency of the replacement of the piston rod, (3) specifying the refitting or realignment of the piston rod, and (4) routing of emission to a process through a closed vent system under negative pressure. In addition to these options, there are emerging control techniques where specific analyses have not yet been conducted. For example, there may be potential for reducing VOC emission by updating rod packing components made from newer materials which can help improve the life and performance of the rod packing system (economic rod packing replacement) and capturing gas from the reciprocating compressor and routing it back to the compressor engine to be used as fuel. These emerging VOC emissions control techniques are discussed briefly below, along with our

evaluation of the frequency of compressor rod packing/piston rod replacement and piston rod refitting and realignment control options.

We do not believe that combustion is a technically feasible control option because, as detailed in the 2011 NSPS TSD, routing of emissions to a control device can cause positive back pressure on the packing, which can cause safety issues due to gas backing up in the distance piece area and engine crankcase in some designs. While considering the option of routing of emissions to a process through a closed vent system under negative pressure, we determined that the negative pressure requirement not only ensures that all the emissions are conveyed to the process, it also avoids the issue of inducing back pressure on the rod packing and the resultant safety concerns. Although this option can be used in some circumstances, it cannot be applied in every installation. As a result, these options (i.e., routing of emissions to a control device, routing of emissions to a process through a closed vent system under negative pressure) were not further considered under this CTG.

Frequency of Rod Packing Replacement

For reciprocating compressors, one of the options for reducing VOC emissions is a maintenance task that would increase or specify the frequency of replacement of the rod packing in order to reduce the leakage of natural gas past the piston rod. Over time, the packing rings wear and allow more natural gas to escape around the piston rod. Regular replacement of these rings reduces VOC emissions. Therefore, this control technique is considered to be an available VOC emission control technique for reciprocating compressors.

Description

As noted previously, reciprocating compressor rod packing consists of a series of flexible rings that fit around a shaft to create a seal against leakage. As the rings wear, they allow more compressed natural gas to escape, increasing rod packing emissions. Rod packing emissions typically occur around the rings from slight movement of the rings in the cups as the rod moves, but can also occur through the “nose gasket” around the packing case, between the packing cups, and between the rings and shaft. If the fit between the rod packing rings and rod is too loose, more compressed natural gas will escape. Periodically replacing the packing rings ensures the correct fit is maintained between packing rings and the rod.⁴⁶

⁴⁶ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR Program. 2006.

Control Effectiveness

As discussed above, regular replacement of the reciprocating compressor rod packing can reduce the leaking of natural gas across the piston rod. The potential emission reductions for gathering and boosting stations and the processing segment were calculated by comparing the average rod packing emissions with the average emissions from newly installed and worn-in rod packing.

Based on industry information from the Natural Gas STAR Program, we have determined that the additional cost of shortening the replacement period more frequently than every three years or every 26,000 hours would not be justified based on the additional emission reductions that would be achieved.⁴⁷ Therefore, we analyzed emission reductions that would result from replacing worn packing with newly installed packing at a frequency of every three years or every 26,000 hours. For the baseline, we assumed that rod packing is replaced every four years. The analysis uses Equation 1 for estimating gathering and boosting station emission reductions, and Equation 2 for estimating processing segment emission reductions that would result from replacing worn packing with newly installed packing at a frequency of every 3 years or every 26,000 hours.⁴⁸

$$\text{Equation 1} \quad R_{WP}^{G\&B} = \frac{Comp_{Existing}^{G\&B} (E_{G\&B} - E_{New}) \times C \times O \times 8760}{10^6}$$

Where:

$R_{WP}^{G\&B}$ = Potential methane emission reductions from gathering and boosting stations by replacing worn packing with newly installed packing, in million cubic feet per year (MMcf/year);

$Comp_{Existing}^{G\&B}$ = Number of existing gathering and boosting station compressors;

$E_{G\&B}$ = Methane emission factor for gathering and boosting stations, in cubic feet per hour per cylinder (25.9 scfh-cylinder);

⁴⁷ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews*. 40 CFR Parts 60 and 63. Response to Public Comments on Proposed Rule. August 23, 2011 (76 FR 52738). pg. 102.

⁴⁸ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution – Background Technical Support Document for Proposed Standards*. July 2011. EPA Document Number EPA-453/R-11-002.

E_{New} = Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder⁴⁹ for this analysis;

C = Average number of cylinders for gathering and boosting stations (i.e., 3.3);

O = Percent of time during the calendar year the average gathering and boosting station is in the operating and standby pressurized modes, 79.1 percent;

8760 = Number of hours in a year;

10^6 = Number of cubic feet in a million cubic feet.

$$\text{Equation 2} \quad R_p = \frac{Comp_{Existing}^P (E_P - E_{New}) \times C \times O \times 8760}{10^6}$$

Where:

R_p = Potential methane emission reductions from processing compressors replacing worn packing to newly installed packing, in million cubic feet per year (MMcf/year);

$Comp_{Existing}^P$ = Number of existing processing compressors;

E_P = Methane emission factor for processing compressors, in cubic feet per hour per cylinder, 57 scfh-cylinder;

E_{New} = Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder⁵⁰ for this analysis;

C = Average number of cylinders for processing compressors (i.e., 2.5);

O = Percent of time during the calendar year the average processing compressor is in the operating and standby pressurized modes, 89.7 percent;

8760 = Number of hours in a year;

10^6 = Number of cubic feet in a million cubic feet.

Table 5-4 presents a summary of the potential emission reductions for reciprocating compressor rod packing replacement for gathering and boosting stations and processing segment compressors based on the percent natural gas reduction calculated from the above equations. The emissions of VOC were estimated using the methane emissions calculated

⁴⁹ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR Program. 2006.

⁵⁰ Ibid.

above and the methane-to-VOC ratio developed for each of the segments in the 2011 Gas Composition Memorandum.

Table 5-4. Estimated Annual Reciprocating Compressor Emission Reductions from Increasing the Frequency of Rod Packing Replacement

Oil and Natural Gas Segment	Individual Compressor Emission Reductions (tons/compressor-year)	
	Methane	VOC
Gathering and Boosting	6.84	1.9
Processing	17.58	4.89

Cost Impacts

Costs for the specified frequency of replacement of reciprocating compressor rod packing documented in the 2011 NSPS TSD were obtained from a Natural Gas STAR Lessons Learned document which estimated the cost to replace the packing rings to be \$1,712 per cylinder (converted from 2008 dollars to 2012 dollars). It was assumed that rod packing replacement would occur during planned shutdowns and maintenance and, therefore, no additional travel costs would be incurred for implementing the rod packing replacement program. In addition, no costs were included for monitoring because the rod packing replacement is based on the number of hours that the compressor operates or the period of time since the previous replacement. The 2011 NSPS TSD analysis assumed that, at baseline, the replacement of rod packing for reciprocating compressors occurs on average every four years based on industry information from the Natural Gas STAR Program. The cost impacts are based on the replacement frequency of the rod packing every 26,000 hours that the reciprocating compressor operates in the pressurized mode.

The 26,000 hour replacement frequency used for the cost impacts in the 2011 NSPS TSD was determined using a weighted average of the annual percentage that the reciprocating compressors are pressurized. The weighted average percentage was calculated to be 98.9 percent. This percentage was multiplied by the total number of hours in 3 years to obtain a value of 26,000 hours. Assuming an interest rate of 7 percent, the capital recovery factors (based on replacing the rod packing every 3 years or 26,000 hours) were calculated to be 0.3122 and 0.3490 for gathering and boosting stations and the processing segment, respectively. The capital

costs were calculated using the average rod packing cost of \$1,712 (converted from \$1,620 in 2008 dollars to 2012 dollars) and the average number of cylinders per compressor (assumed to be 3.3 cylinders for gathering and boosting stations and 2.5 cylinders for processing segment compressors).⁵¹ The annual costs were calculated using the capital costs and the capital recovery factors. Table 5-5 presents a summary of the capital and annual costs for gathering and boosting stations and the processing segment.

There are monetary savings associated with the amount of gas saved with reciprocating compressor rod packing replacement. Monetary savings associated with the amount of gas saved with reciprocating compressor rod packing replacement was estimated using a natural gas price of \$4.00 per Mcf.⁵² Table 5-5 presents the annual costs with savings and cost of control for reciprocating rod packing replacement for gathering and boosting stations and the processing segment.

Reciprocating compressor rod packing replacement prevents the escape of natural gas from the piston rod. In addition to reducing VOC emissions, there would be a co-benefit of reducing other emissions (such as methane) as a result of increasing the frequency of rod packing replacement.

Table 5-5. Cost of Control for Increasing the Frequency of Reciprocating Compressor Rod Packing Replacement

Oil and Gas Segment	Capital Cost (\$2012) ^a	Annual Costs per Compressor (\$/compressor-year)		VOC Cost of Control (\$/ton)	
		Without Savings	With Savings	Without Savings	With Savings
Gathering and Boosting	\$5,650	\$2,153	\$566	\$1,131	\$298
Processing	\$4,280	\$1,631	(\$2,443)	\$334	(\$500)

^a 2011 TSD 2008 dollars converted to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflator (5.69 percent).

⁵¹ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution – Background Technical Support Document for Proposed Standards*. July 2011. EPA Document Number EPA-453/R-11-002.

⁵² U.S. Energy Information Administration. *Annual U.S. Natural Gas Wellhead Price*. U.S. Energy Information Administration *Natural Gas Navigator*. Retrieved online on December 12, 2010 at <http://www.eia.doe.gov/dnav/ng/hist/n9190us3a.htm>.

Frequency of Replacement and/or Realignment/Retrofitting of the Piston Rod

Like the packing rings, piston rods on reciprocating compressors also deteriorate. Piston rods, however, wear more slowly than packing rings, having a life of about 10 years.⁵³ Rods wear “out-of-round” or taper when poorly aligned, which affects the fit of packing rings against the shaft (and therefore the tightness of the seal) and the rate of ring wear. An out-of-round shaft not only seals poorly, allowing more leakage, but also causes uneven wear on the seals, thereby shortening the life of the piston rod and the packing seal. Replacing or upgrading the rod can reduce reciprocating compressor rod packing emissions. Also, upgrading piston rods by coating them with tungsten carbide or chrome reduces wear over the life of the rod. We assume that operators will choose, at their discretion, when to replace/realign or retrofit the rod as part of regular maintenance procedures and replace the rod when appropriate when the compressor is out of service for other maintenance such as rod packing replacement. Therefore, we did not consider this option any further.

Updated Rod Packing Material

Although specific analyses have not been conducted, there may be potential for reducing VOC emissions by updating rod packing components made from newer materials, which can help improve the life and performance of the rod packing system. One option is to replace the bronze metallic rod packing rings with longer lasting carbon-impregnated Teflon rings. Compressor rods can also be coated with chrome or tungsten carbide to reduce wear and extend the life of the piston rod.⁵⁴ Although changing the rod packing material has been identified as a potential VOC emission reduction option for reciprocating compressors, there is insufficient information on its emission reduction potential and use throughout the industry.

Economic Rod Packing Replacement

Another option facilities can use that has the potential to reduce costs and emissions is for facilities to use specific financial objectives and monitoring data to determine emission levels at which it is cost-effective to replace rings and rods. Benefits of calculating and utilizing this “economic replacement threshold” include VOC emission reductions and natural gas cost savings. Using this approach, one Natural Gas STAR partner reportedly achieved savings of over

⁵³ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR Program. 2006.

⁵⁴ Ibid.

\$233,000 annually at 2006 gas prices. An economic replacement threshold approach would also result in operational benefits, including a longer life for existing equipment, improvements in operating efficiencies, and long-term savings.⁵⁵

Gas Recovery (Routing of Emissions to a Process)

Description

Another control option for reciprocating compressors includes control techniques that recover natural gas leaking past the piston rod packing. We are aware of a system that captures the natural gas that would otherwise be vented and routes it back to the compressor engine to be used as fuel.⁵⁶ The vent gases are passed through a valve train that includes a demister and then are injected into the engine intake air after the air filter. In general, the technology consists of recovering vented emissions from the rod packing under negative pressure and routing these emissions of otherwise vented gas to the air intake of a reciprocating internal combustion engine that would burn the gas as fuel to augment the normal fuel supply. The system's computerized air/fuel control system would then adjust the normal fuel supply to accommodate the increased fuel made available from the recovered emissions and thereby take advantage of the recovered emissions while avoiding an overly rich fuel mixture.

Subpart OOOO, as well as subpart OOOOa, provide a compliance option for reciprocating compressors that allows collecting emissions from the rod packing using a rod packing emissions collection system which operates under negative pressure and routing the rod packing emissions to a process through a closed vent system. Both of the above systems, if installed using a cover and closed vent system meeting the subpart OOOO and subpart OOOOa requirements, could potentially be used for this compliance option.

Control Effectiveness

One estimate obtained by the EPA states that the gas recovery system can result in the elimination of over 99 percent of VOC emissions that would otherwise occur from the venting of the emissions from the compressor rod packing.⁵⁷ The emissions that would have been vented are combusted in the compressor engine to generate power.

⁵⁵ Ibid.

⁵⁶ REM Technology Inc. and Targa Resources. *Reducing Methane and VOC Emissions*. Presentation for the 2012 Natural Gas STAR Annual Implementation Workshop.

⁵⁷ REM Technology Inc., et al. *Profitable Use of Vented Emission in Oil & Gas Production*. Prepared with support from the Climate Change and Emissions Management Corporation (CCEMC). 2013.

If the facility is able to route rod packing vents to a VRU system, it is possible to recover approximately 95-100 percent of emissions. If the gas is routed to a flare, approximately 95 percent of the VOC emissions could be reduced.

Cost Impacts

One estimate reported that the cost per engine would be approximately \$12,000 (does not include installation costs). Some costs would be mitigated by fuel gas savings, as using the captured gas to displace some of the purchased fuel would require less fuel to be purchased in order to run the compressor engine. The fuel cost saving based on a 4-throw compressor with moderate leak rate would be an estimated \$6,500 per year.⁵⁸ This technique is discussed further in the Natural Gas STAR PRO Fact Sheet titled “Install Automated Air/Fuel Ratio Controls”.⁵⁹ This document reported an average fuel gas savings of 78 Mcf/day per engine with the gas recovery system installed. Based on our review of information on this technology, we conclude that this technology has merit and would provide better emission reductions than increasing the replacement of rod packing from every 4 years to every 3 years since the emissions would be captured under negative pressure, allowing all emissions to be routed to the engine. It is our understanding that this technology may not be applicable to every compressor installation and situation.

For a VRU, assuming the proper equipment is already available at the facility, capturing the rod packing emissions would require minimal costs. The investment would only need to include the cost of piping and installation. While we have not obtained a cost estimate specifically for routing rod packing vents to a VRU, this process has been studied for dehydrators and would be similar for rod packing systems. According to the Natural Gas STAR PRO Fact Sheet titled “Pipe Glycol Dehydrator to Vapor Recovery Unit,”⁶⁰ the cost for planning and installing additional piping is approximately \$2,000. Routing to a VRU also provides additional incentive as there is a value associated with recovered gas. However, the installation of a VRU to only capture rod packing emissions may not be economically viable if an additional compressor system is required. If the VRU is already present at the facility, the incremental cost

⁵⁸ REM Technology Inc. Presentation to the U.S. Environmental Protection Agency on December 1, 2011. EPA Docket ID No. EPA-HQ-OAR-2010-0505.

⁵⁹ U.S. Environmental Protection Agency. Gas STAR PRO No. 104. *Install Automated Air/Fuel Ratio Controls*. 2011.

⁶⁰ U.S. Environmental Protection Agency. Gas STAR PRO No. 203. *Pipe Glycol Dehydrator to Vapor Recovery Unit*. 2011.

to capture the rod packing vent gas can be recovered from the value of the additional captured natural gas.

Although gas recovery has been identified as a potential VOC emission reduction option for reciprocating compressors, there is insufficient information on its availability as a reasonably available control option for reducing reciprocating compressor VOC emissions. However, we recommend that air agencies consider this technology as a compliance option when considering the RACT recommendations presented in section 5.4 of this chapter.

5.3.1.2 Centrifugal Compressors Equipped with Wet Seals

Potential control options to reduce emissions from centrifugal compressors equipped with wet seals include control techniques that limit the leaking of natural gas across the rotating shaft, and capture and destruction of the emissions by routing emissions to a process (e.g., a compressor or fuel gas system) or to a combustion device (discussed in detail in sections 4.3.1.2 of chapter 4). We evaluate below three available control options: (1) converting wet seals to dry seals, (2) routing emissions to a fuel gas system or compressor (process), and (3) routing emissions to a combustion device.

Converting Wet Seals to Dry Seals

Description

We evaluated the use of centrifugal compressor dry seals as an available VOC control option for wet seal centrifugal compressors. As noted in section 5.2 of this chapter, the VOC emission profile from the use of dry seals is considerably less than from the use of wet seals. Replacing wet seals with dry seals can, therefore, substantially reduce VOC emissions across the rotating shaft compared to wet seals, while simultaneously reducing operating costs and enhancing compressor efficiency compared to wet seals. During normal operation, dry seals leak at a rate of 6 scfm methane per compressor.⁶¹ While this is equivalent to a wet seal's leakage rate at the seal face, wet seals generate additional emissions during degassing of the circulating oil. Gas separated from the seal oil before the oil is recirculated is usually vented to the atmosphere,

⁶¹ U.S. Environmental Protection Agency. Lessons Learned Document. *Replacing Wet Seals with Dry Seals in Centrifugal Compressors*. October 2006.

bringing the total leakage rate for tandem wet seals to 47.7 scfm methane per compressor.^{62,63} It is not practical or feasible in all situations, however, to retrofit an existing wet seal compressor with a dry seal compressor. We have received information that indicates that the conversion process requires a significant period of time to complete and the compressor would need to be out of commission for the conversion period.

Control Effectiveness

The emission reductions that would occur by replacing wet seal compressors with a dry seal compressor were calculated by subtracting the dry seal emissions from the emissions from a centrifugal compressor equipped with wet seals. We used the centrifugal compressor emission factors in Table 5-2 and estimated that VOC emissions would be reduced by 16.7 tpy per compressor.

Cost Impacts

The Natural Gas STAR Program estimated the cost of retrofitting dry seals on a centrifugal compressor equipped with wet seals to be \$324,000 (\$342,439 in 2012 dollars) for a two-seal dry seal system, which includes the cost of both seals and the dry gas conditioning, monitoring, control console and installation.⁶⁴ The annual costs were calculated as the capital recovery of the capital cost assuming a 20-year equipment life and 7 percent interest, which is approximately \$32,324 per compressor. The Natural Gas STAR Program estimated that the annual operation and maintenance savings from the installation of a dry seal compressor is \$88,300 (\$93,325 in 2012 dollars) in comparison to a wet seal compressor. In addition, the installation of dry seals reduces natural gas emissions by 10,721 Mscf/yr⁶⁵ which results in an estimated natural gas savings of \$42,883 per year assuming a natural gas price of \$4/Mcf. A summary of the capital and annual costs for replacing a wet seal compressor with a dry seal compressor is presented in Table 5-6 along with the VOC cost of control. As noted above, we

⁶² U.S. Environmental Protection Agency, et al. *Methane's Role in Promoting Sustainable Development in the Oil and Natural Gas Industry*. World Gas Conference 10/2009.

⁶³ U.S. Environmental Protection Agency. *Methodology for Estimating CH₄ and CO₂ Emissions from Natural Gas Systems. Inventory of U.S. Greenhouse Gas Emission and Sinks: 1990-2012*. Washington, DC. Annex 3. Table A-129.

⁶⁴ U.S. Environmental Protection Agency. Lessons Learned Document. *Replacing Wet Seals with Dry Seals in Centrifugal Compressors*. October 2006.

⁶⁵ The natural gas savings was calculated by using the 16.7 tpy VOC reduction and dividing by the VOC/methane weight ratio of 0.278 to determine the amount of methane reduction that would be reduced (60.1 tpy). The methane emission reductions were converted to volumetric natural gas reductions assuming a natural gas density of 0.02082 tons/Mcf and an 82.9 volume percent conversion factor of methane to natural gas.

have received information that indicates that the conversion process requires a significant period of time to complete and the compressor would need to be out of commission during the conversion period. Because of this, a facility may have to provide a temporary compressor in the interim that would add additional costs to the cost estimates we present in Table 5-6.

Table 5-6. Cost of Control of Replacing a Wet Seal Compressor with a Dry Seal Compressor

Oil & Natural Gas Segment	Capital Cost (\$2012)	Annual Costs Per Compressor (\$/compressor-year)		VOC Cost of Control (\$/ton)	
		Without Savings ^a	With O&M and Natural Gas Savings ^b	Without Savings	With O&M and Natural Gas Savings
Processing	\$342,439	\$32,324	(\$103,884)	\$1,931	(\$6,205)

^a Includes only the annualized capital cost of the retrofit of the dry seal system (20 years, 7 percent interest).

^b Includes the annualized capital cost, annual operation and maintenance (O&M) savings and annual natural gas savings.

Routing Emissions to a Compressor or Fuel Gas System (Process)

Description

One option for reducing VOC emissions from the compressor wet seal fluid degassing system is to route the captured emissions back to the compressor suction or fuel system or other beneficial use (referred to collectively as routing to a process). Routing to a process would entail routing emissions via a closed vent system to any enclosed portion of a process unit (e.g., compressor or fuel gas system) where the emissions are predominantly recycled, consumed in the same manner as a material that fulfills the same function in the process, transformed by chemical reaction into materials that are not regulated materials, incorporated into a product, or recovered. Emissions that are routed to a process can result in the same or greater emission reductions as would have been achieved had the emissions been routed through a closed vent system to a combustion device. Table 5-7 presents a summary of the estimated emission reductions from routing emissions from the wet seal fluid degassing system to a process. For purposes of this analysis, we assume that routing VOC emissions from a wet seal fluid degassing

system to a process reduces VOC emissions greater than or equal to a combustion device (i.e., greater than or equal to 95 percent).

Table 5-7. Estimated Annual Centrifugal Compressor VOC Emission Reductions for Routing Wet Seal Fluid Degassing System to a Process^{66,67}

Oil & Gas Segment	Individual Compressor VOC Emission Reductions (tons/compressor-year)
Processing	≥ 18.1

Cost Impacts

The capital cost of a system to route the seal oil degassing system to a process is estimated to be \$23,252,⁶⁸ converting to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflator (Change in GDP: Implicit Price Deflator from 2008 to 2012 (5.69 percent)).⁶⁹ The estimated costs include an intermediate pressure degassing drum, new piping, gas demister/filter, and a pressure regulator for the fuel line. The annual costs were estimated to be \$2,553 assuming a 15-year equipment life at 7 percent interest.

Potential natural gas savings for this option were estimated to be 12 Mcf/yr and assumes that greater than or equal to 95 percent of the 47.7 scfm methane emissions are controlled, an annual operating factor of 43.6 percent, and the 82.9 volume percent conversion factor of methane to natural gas. Assuming a natural gas savings of \$4/Mcf, the natural gas savings equates to approximately \$47,553 per year. Table 5-8 presents a summary of the cost of control for routing emissions to a process.

⁶⁶ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.

⁶⁷ Ibid.

⁶⁸ Ibid.

⁶⁹ U.S. Bureau of Economic Analysis. *Gross Domestic Product: Implicit Price Deflator (GDPDEF)*, retrieved from FRED, Federal Reserve Bank of St. Louis. <https://research.stlouisfed.org/fred2/series/GDPDEF/> March, 26, 2015.

Table 5-8. VOC Cost of Control for Routing Wet Seal Fluid Degassing System to a Process^a

Oil and Gas Segment	Capital Cost (\$2012) ^a	Annual Costs per Compressor (\$/compressor-year)		VOC Cost of Control (\$/ton)	
		Without Savings	With Savings	Without Savings	With Savings
Processing	\$23,252	\$2,553	(\$47,553)	\$141	(\$2,621)

^a 2011 TSD 2008 dollars converted to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflator (Change in GDP: Implicit Price Deflator from 2008 to 2012 (5.69 percent)).⁷⁰

Routing Emissions to a Combustion Device

Description

Combustion devices are commonly used in the oil and natural gas industry to combust VOC emission streams. Typical combustion devices used in the oil and natural gas industry to control VOC emissions and their control efficiency are discussed in greater detail in section 4.3.1.2 of chapter 4 of this document. Similar to the analysis of storage vessels, for this analysis, we assumed that the entrained natural gas from the seal oil that is removed in the degassing process would be directed to a combustion device that achieves a 95 percent reduction of VOC. The wet seal emissions in Table 5-2 were used along with the control efficiency to calculate the emission reductions. Table 5-9 presents a summary of the estimated emission reductions from routing emissions from the wet seal to a combustion device.

Table 5-9. Estimated Annual VOC Emission Reductions for Routing Wet Seal Fluid Degassing System to a Combustion Device⁷¹

Oil & Gas Segment	Individual Compressor VOC Emission Reductions (tons/compressor-year)
Processing	18.1

⁷⁰ Ibid.

⁷¹ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.

Cost Impacts

Routing the captured gas from the centrifugal compressor wet seal degassing system to an existing combustion device or installing a new combustion device has associated capital and operating costs. The capital and annual costs of the combustion device (an enclosed flare for the analysis) were calculated using the methodology in the EPA Control Cost Manual.⁷² The heat content of the gas stream was calculated using information from the 2011 Gas Composition Memorandum. Table 5-10 presents a summary of the capital and annual costs for wet seals routed to a flare, as well as the VOC cost of control. There is no cost savings estimated for this option because the recovered natural gas is combusted.

Table 5-10. Cost of Control for Routing Wet Seal Fluid Degassing System to a Combustion Device

Industry Segment	Capital Cost (\$)		Annual Cost per Compressor (\$/compressor-year)		VOC Cost of Control New CD (\$/ton)	VOC Cost of Control Existing CD (\$/ton)
	New CD	Existing CD	New CD	Existing CD		
Processing	\$71,783	\$23,252	\$114,146	\$3,311	\$6,292	\$183

CD = Control Device

5.3.2 Existing Federal, State and Local Regulations

5.3.2.1 Federal Regulations that Specifically Require Control of VOC Emissions

Under the 2012 NSPS and 2016 NSPS, reciprocating compressors are required to limit VOC emissions by replacing the rod packing on or before 26,000 hours of operation or 36 months since the previous rod packing replacement. Alternatively, an owner or operator is allowed to route rod packing emissions to a process through a closed vent system under negative pressure. For centrifugal compressors in the processing segment, the 2012 NSPS and 2016 NSPS require that VOC emissions be reduced from each centrifugal compressor wet seal fluid degassing system by 95 percent.

⁷² U.S. Environmental Protection Agency. *OAQPS Control Cost Manual: Sixth Edition* (EPA 452/B-02-001). Research Triangle Park, NC.

5.3.2.2 *State and Local Regulations that Specifically Require Control of VOC Emissions*

States may have permitting restrictions on VOC emissions that may apply to an emissions source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met and, often, how the source must be operated. To ensure that sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

Montana requires oil and natural gas well facilities to control emissions from the time the well is completed until the source is registered or permitted. Each piece of oil or natural gas well facility equipment, with VOC vapors of 200 Btu/scf or more with a PTE greater than 15 tpy, is required to (1) capture and route emissions to a natural gas pipeline, (2) route to a smokeless combustion device equipped with an electronic ignition device or a continuous burning pilot system meeting the requirements of 40 CFR 60.18 and operating at 95 percent or greater control efficiency, or (3) route to air pollution control equipment with equal or greater control efficiency than a smokeless combustion device. This includes the control of emissions from compressor engines used for transmission of natural gas (Registration of Air Contaminant Sources, Rule 17.8.1711 Oil or Gas Well Facilities Emission Control Requirements).

Colorado (Regulation 7, XVII.B.3.b and c) requires that uncontrolled actual hydrocarbon emissions from wet seal fluid degassing systems on wet seal centrifugal compressors be controlled by at least 95 percent, unless the centrifugal compressor is subject to 40 CFR part 60, subpart OOOO. Additionally, Regulation 7 requires that rod packing on any reciprocating compressor located at a natural gas compressor station be replaced every 26,000 hours of operation or every 36 months, unless the reciprocating compressor is subject to 40 CFR part 60, subpart OOOO.

5.4 Recommended RACT Level of Control

For reciprocating compressors, there are federal and state regulations that require the periodic replacement of reciprocating compressor packing. The federal regulations (the 2012 NSPS and 2016 NSPS) require the replacement of reciprocating compressor rod packing every 3 years or on or before 26,000 hours of operation. The state regulation (Colorado) requires the

replacement of reciprocating compressor rod packing every 26,000 hours of operation or every 36 months. The 2012 NSPS and 2016 NSPS also provide the alternative of routing rod packing emissions to a process via a closed vent system under negative pressure.

As noted in section 5.3 of this chapter, the most significant volume of VOC emissions are associated with piston rod packing systems. We found that, under the best conditions, regular rod packing replacement, when carried out approximately every three years, effectively controls emissions and helps prevent excessive rod wear. The cost of control for requiring the replacement of reciprocating packing at this frequency was estimated to be \$1,132 per ton of VOC reduced without savings and \$298 per ton of VOC reduced considering savings for gathering and boosting station compressors, and about \$334 per ton of VOC reduced without savings, and an overall net savings per ton of VOC reduced for processing segment reciprocating compressors considering savings. Based on the emission reductions, costs (considering gas savings) and existing and currently implemented regulations that require the replacement of the reciprocating compressor packing every 36 months or on or before 26,000 hours of operation, we recommend this control option as RACT for reciprocating compressors in the production and processing segments (excluding compressors at the well site). We also recommend that air agencies provide operators the compliance alternative of routing rod packing emissions to a process via a closed vent system under negative pressure.

For centrifugal compressors, there are already federal, state and local regulations that require the capture and 95 percent control of emissions from wet seal fluid degassing systems from centrifugal compressors. Although dry seal systems have low VOC emissions and the option of routing to a process has at least a 95 percent control efficiency, the replacement of wet seals with dry seals and routing to a process may not be technically feasible or practical options for some centrifugal compressors. The integration of a centrifugal compressor into an operation may require a certain compressor size or design that is not available in a dry seal model, and, in the case of capture of emissions with routing to a process, there may not be downstream equipment capable of handling a low-pressure fuel source. As a result of our evaluation of the technical feasibility and practicality of existing available controls, we recommend RACT be 95 percent control of emissions from the wet seal degassing system, which can be achieved by using a closed vent system and routing emissions to a combustor or routing the emissions back to the compressor or fuel line (routing to the process). For the processing segment, we assume that

there is an existing combustion device onsite and the estimated cost of control would be about \$183 per ton of VOC reduced for facilities to route emissions to the existing combustion device, or about \$141 per ton of VOC reduced for facilities to route the captured emissions back to the compressor or fuel line.

In summary, we recommend the following as RACT for compressors:

- (1) RACT for Reciprocating Compressors Located Between the Wellhead and Point of Custody Transfer to the Natural Gas Transmission and Storage Segment (Excludes the Well Site): We recommend that each reciprocating compressor reduce VOC emissions by replacing the rod packing on or before 26,000 hours of operation or 36 months since the last rod packing replacement. We also recommend that an alternative be provided to allow routing of rod packing emissions to a process via a closed vent system under negative pressure in lieu of the specified rod packing replacement periods. We do not recommend that RACT apply to individual reciprocating compressors located at a well site, or an adjacent well site and servicing more than one well site.
- (2) RACT for Centrifugal Compressors Using Wet Seals Located Between the Wellhead and Point of Custody Transfer to the Natural Gas Transmission and Storage Segment (Excludes the Well Site): We recommend that each centrifugal compressor using wet seals reduce VOC emissions from each wet seal fluid gassing system by reducing VOC emissions by 95 percent. We do not recommend that RACT apply to individual centrifugal compressors using wet seals located at a well site, or an adjacent well site and servicing more than one well site.

5.5 Factors to Consider in Developing Compressor Compliance Procedures

5.5.1 Reciprocating Compressor Compliance Recommendations

In order to ensure and demonstrate compliance with the recommended RACT for reciprocating compressors, we recommend that air agencies require facilities to maintain a record of the date of the most recent reciprocating compressor rod packing replacement, monitor and keep records of the number of hours of operation and/or track the number of months since the last rod packing replacement for each reciprocating compressor (to meet the requirement that the packing is changed out on or before the total number of hours of operation reaches 26,000 hours

or the number of months since the most recent rod packing replacement reaches 36 months) and maintain records of instances where the reciprocating compressor was not operated in compliance with RACT. This may require the installation of an operating hours meter on the engine to track the number of hours of operation. We also recommend that air agencies require annual reports of the cumulative hours of operation or number of months since packing replacement for each reciprocating compressor and instances when there were deviations where the reciprocating compressor was not operated in compliance with the recommended RACT.

For applications in which operators choose to opt for the alternative of routing of rod packing emissions to a process via a closed vent system under negative pressure, it is recommended that air agencies require facilities to maintain records of the date of installation of a rod packing emissions collection system and closed vent system and maintain records of instances of deviations in cases where the reciprocating compressor was not operated in compliance with requirements. We also recommend that air agencies require annual reports for each reciprocating compressor complying with this option indicating when there were deviations where the reciprocating compressor was not operated in compliance with the recommended RACT. Recommended cover and closed vent system design and operation measures are specified in sections 5.5.3 and 5.5.4.

The appendix to this document presents example model rule language that incorporates compliance elements recommended in this section that air agencies may choose to use in whole or in part.

5.5.2 Centrifugal Compressor Equipped with a Wet Seal Recommendations

In order to ensure that VOC emissions are reduced by at least 95 percent (the recommended RACT level of control) from a centrifugal compressor equipped with a wet seal when using a control device or other control measure (such as routing to a process), the centrifugal compressor should be equipped with a cover that is connected through a closed vent system that routes emissions to the control device (or process) that meets the RACT level of control. Recommended cover and closed vent system design and operation measures are specified in sections 5.5.3 and 5.5.4. Recommended control device operation and monitoring provisions for specified controls to ensure compliance are presented in section 5.5.5.

The appendix of this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part.

5.5.3 Recommendations for Cover Design

The cover and all openings on the cover should form a continuous impermeable barrier over the entire surface area of the liquid in the wet seal fluid degassing system (for centrifugal compressors), and of the rod packing emissions collection system (for reciprocating compressors). Each cover opening should be secured in a closed, sealed position (e.g., covered by a gasketed lid or cap) except during those times when it is necessary to use an opening as follows:

- (1) To inspect, maintain, repair, or replace equipment; or
- (2) To vent gases or fumes from the unit, through a closed vent system designed and operated in accordance with closed vent system requirements (see section 5.5.4), to a control device or to a process.

It is recommended that air agencies require olfactory, visual and auditory inspections of covers for defects that could result in air emissions on a monthly basis. We recommend air agencies require that any detected defects be repaired as soon as practicable.

5.5.4 Recommendations for Closed Vent Systems

The closed vent system should be designed and operated with no detectable emissions (using a 500 ppm detection level, as measured using Method 21 of appendix A-7 of Part 60, and ongoing monthly olfactory, visual and auditory inspections). It is recommended that air agencies require that any detected defects be repaired as soon as practicable.

With the exception of low leg drains, high point bleeds, analyzer vent, open-ended valves and safety devices, if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process, air agencies should require that owners or operators either:

- (1) Install, calibrate, maintain and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings and either sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open

such that the stream is being, or could be, diverted away from the control device or process to the atmosphere; or

- (2) Secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

5.5.5 Recommendations for Control Device Operation and Monitoring

If a control device is used to comply with the recommended 95 percent VOC emission reduction RACT level of control, we advise that the device be required to operate at all times when gases, vapors, and fumes are vented from the wet seal fluid degassing system through the closed vent system to the control device. The following paragraphs present select emission control options and suggested operation and monitoring requirements, as appropriate to ensure compliance with the recommended RACT level of control.

Enclosed Combustion Devices

If an enclosed combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) is used to meet the 95 percent VOC emission reduction RACT level of control, it should be designed to reduce the mass content of VOC emissions by 95 percent or greater and be: (1) maintained in a leak free condition, (2) installed and operated with a continuous burning pilot flame, and (3) operated with no visible emissions.

It is recommended that the visible emissions test (using section 11 of EPA Method 22, 40 CFR part 60, appendix A-7) be performed at least once every calendar month. If a combustion device fails the visible emissions test, sources should be required to follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. It is recommended that all inspection, repair and maintenance activities for each unit be recorded in a maintenance and repair log that can be made available for inspection. Following return to operation from maintenance or repair activity, each device should be required to pass a Method 22, 40 CFR part 60, appendix A-7 visual emissions test.

It is recommended that air agencies require that sources meeting the 95 percent VOC emission reduction RACT level of control by routing emissions to a combustion device conduct performance tests and/or design analyses that demonstrate that the combustion device being used meets the required 95 percent VOC emission reduction RACT level of control (see section F of

the appendix to this document for performance testing procedures for control devices that we recommend be used to demonstrate performance requirements).

Routing to a Process

Routing to a process would entail routing emissions via a closed vent system to any enclosed portion of a process unit where the emissions are predominantly recycled, consumed in the same manner as a material that fulfills the same function in the process, transformed by chemical reaction into materials that are not regulated materials, incorporated into a product, or recovered. Vapor recovery units and flow lines that “route emissions to a process” would be considered part of the process and would not be considered control devices that are subject to standards, but the recommended cover and closed vent system design, operation and monitoring requirements specified in sections 5.5.3 and 5.5.4 would apply.

6.0 PNEUMATIC CONTROLLERS

The oil and natural gas industry uses a variety of process control devices to operate valves that regulate pressure, flow, temperature and liquid levels. Most instrumentation and control equipment falls into one of three categories: (1) pneumatic, (2) electrical, or (3) mechanical. Of these, only pneumatic devices are direct sources of air emissions. Pneumatic controllers are pneumatic devices used throughout the oil and natural gas industry as part of the instrumentation to control the position of valves and may be actuated using pressurized natural gas (natural gas-driven) or may be actuated by another means such as a pressurized gas other than natural gas, solar, or electric. This chapter describes pneumatic controllers that are used in the oil and natural gas industry, including their function and associated emissions. This chapter also presents control techniques used to reduce VOC emissions from these pneumatic controllers, along with costs and emission reductions. Finally, this chapter discusses our recommended RACT and the associated VOC emission reductions and costs for pneumatic controllers.

6.1 Applicability

For the purposes of this CTG, a pneumatic controller is an automated instrument used to maintain a process condition such as liquid level, pressure, pressure differential and temperature. The emissions and emission controls discussed herein would apply to natural gas-driven pneumatic controllers in the oil and natural gas industry located from the wellhead to a natural gas processing plant (including the natural gas processing plant) or from the wellhead to the point of custody transfer to an oil pipeline.

6.2 Process Description and Emission Sources

6.2.1 Process Description⁷³

Natural gas-driven pneumatic controllers come in a variety of designs for a variety of uses. For the purposes of this CTG, they are characterized primarily by their emission characteristics:

- (1) *Continuous bleed pneumatic controllers* are used to modulate flow, liquid level, or pressure, and gas is vented continuously at a rate that may vary over time. Continuous bleed controllers are further subdivided into two types based on their bleed rate:
 - a. *Low-bleed*, having a bleed rate of less than or equal to 6 standard cubic feet per hour (scfh).
 - b. *High-bleed*, having a bleed rate of greater than 6 scfh.
- (2) *Intermittent bleed or snap-acting pneumatic controllers* release gas only when they open or close a valve or as they throttle the gas flow.
- (3) *Zero-bleed pneumatic controllers* do not bleed natural gas to the atmosphere. These natural gas-driven pneumatic controllers are self-contained devices that release gas to a downstream pipeline instead of to the atmosphere.

Pneumatic controllers often make use of available high-pressure natural gas to operate or control a valve. The supply gas pressure is modulated by a process condition, and then flows to the valve controller where the signal is compared with the process set point to adjust gas pressure in the valve actuator. In these natural gas-driven pneumatic controllers, natural gas may be released intermittently with every actuation of the valve. In other designs, natural gas may be released continuously from the valve control pilot. The rate at which the continuous release occurs is referred to as the bleed rate. Bleed rates are dependent on the design and operating characteristics of the device. Similar designs will have similar steady state rates when operated under similar conditions. It is our understanding that self-contained devices that release natural gas to a downstream pipeline instead of to the atmosphere have no emissions. “Closed loop” systems are applicable only in instances with very low pressure⁷⁴ and may not be suitable to

⁷³ U.S. Environmental Protection Agency. *Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

⁷⁴ Memorandum to Bruce Moore, U.S. Environmental Protection Agency, from Denise Grubert, EC/R Incorporated. *Meeting Minutes from EPA Meeting with the American Petroleum Institute (API)*. October 2010.

replace many applications of continuous or intermittent bleed pneumatic devices. Therefore, this CTG does not address these self-contained devices further.

Intermittent controllers are devices that only emit gas during actuation and do not have a continuous bleed rate. The actual amount of emissions from an intermittent controller is dependent on the amount of natural gas vented per actuation and how often it is actuated. Bleed devices also vent an additional volume of gas during actuation, in addition to the controller's bleed stream. Since actuation emissions serve the controller's functional purpose and can be highly variable, the emissions characterized for high-bleed and low-bleed devices in this analysis (as described in section 6.2.2) account for only the continuous flow of emissions (i.e., the bleed rate) and do not include emissions directly resulting from actuation. Intermittent controllers are assumed to have zero bleed emissions. For most applications (but not all), intermittent controllers serve functionally different purposes than bleed devices. Therefore, because the total emissions are dependent on the application in which they are used, we do not consider their use to be a technically practical control option for all continuous bleed controllers.

As previously indicated, not all pneumatic controllers are natural gas driven. At sites with a continuous and reliable source of electricity, controllers can be actuated by an instrument air system that uses compressed air instead of natural gas. These sites may also use mechanical or electrically powered pneumatic controllers. In some instances, solar-powered controllers may be feasible. Because these devices are not natural gas driven, they do not directly release natural gas or VOC. However, electrically powered systems have energy impacts, with associated secondary impacts related to generation of the electrical power required to drive the instrument air compressor system. To our knowledge, natural gas processing plants are the only facilities in the oil and natural gas industry that are likely to have electrical service sufficient to power an instrument air system, and most existing natural gas processing plants use instrument air instead of natural gas-driven devices.⁷⁵

⁷⁵ U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices*. EPA-600/R/-96-080k. June 1996.

6.2.2 Emissions Data

6.2.2.1 Summary of Major Studies and Emissions

In the evaluation of the emissions from pneumatic controllers and the potential options available to reduce VOC emissions, numerous studies were consulted. Table 6-1 lists these references with an indication of the type of relevant information contained in each reference. In addition to these sources, we evaluated the peer reviewer and public comments received on the EPA’s white paper, “Oil and Natural Gas Sector Pneumatic Devices.”⁷⁶

Table 6-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options ¹
Greenhouse Gas Reporting Program (Annual Reporting; Current Data Available for 2011-2013) ^a	EPA	2014	Facility-Level	X	X
Inventory of Greenhouse Gas Emissions and Sinks ^b	EPA	Annual	Nationwide/ Regional	X	
Methane Emissions from the Natural Gas Industry ^c	EPA/GRI	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry ^d	EPA/GRI	1996	Nationwide	X	
Methane Emissions from the U.S. Oil Industry ^e	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States ^f	WRAP	2005	Regional	X	
Natural Gas STAR Program ^g	EPA	2000 – 2010	Voluntary	X	X
Measurements of Methane Emissions from Natural Gas Production Sites in the United States ^h	Multiple Affiliations, Academic and Private	2013	Nationwide	X	

⁷⁶ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Pneumatic Devices. Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel*. Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at <http://www.epa.gov/airquality/oilandgas/2014papers/20140415pneumatic.pdf>.

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options ^l
Determining Bleed Rates for Pneumatic Devices in British Columbia ⁱ	The Prasino Group	2013	British Columbia	X	
Air Pollutant Emissions from the Development, Production, and Processing of Marcellus Shale Natural Gas ^j	Carnegie Mellon University	2014	Regional (Marcellus Shale)	X	
Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries ^k	ICF International	2014	Nationwide	X	X

^a U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC.

^b U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. <https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html>.

^c U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 2: Technical Report*. EPA-600/R-96-080b. June 1996; U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 3: General Methodology*. EPA-600/R-96-080c. June 1996; U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 5: Activity Factors*. EPA-600/R-96-080e. June 1996; and U.S. Environmental Protection Agency. *Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices*. EPA-600/R-96-080k. June 1996.

^d U.S. Environmental Protection Agency/GRI. *Methane Emissions from the U.S. Petroleum Industry. Draft Report*. June 14, 1996.

^e ICF Consulting. *Estimates of Methane Emissions from the U.S. Oil Industry*. Prepared for the U.S. Environmental Protection Agency. 1999.

^f ENVIRON International Corporation. *Oil and Gas Emission Inventories for the Western States*. Prepared for Western Governors Association. December 27, 2005.

^g U.S. Environmental Protection Agency. *Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR. Washington, DC. October 2006.

^h Memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. *Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking*. July 2011.

ⁱ U.S. Environmental Protection Agency. *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas Star. Washington, DC. 2006.

^j U.S. Environmental Protection Agency. Pro Fact Sheet No. 301. *Convert Pneumatics to Mechanical Controls*. Office of Air and Radiation: Natural Gas Star. Washington, DC. September 2004.

^k Canadian Environmental Technology Advancement Corporation (CETAC)-WEST. *Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Pneumatic Instruments*. Prepared for the Canadian Association of Petroleum Producers. May 2008.

¹ An “X” in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

6.2.2.2 *Representative Pneumatic Controller Device Emissions*

For purposes of this CTG, continuous bleed pneumatic controllers are classified into two types based on their emissions rates: (1) high-bleed controllers, and (2) low-bleed controllers. A controller is considered to be high-bleed when the continuous bleed emissions are in excess of 6 scfh, while low-bleed devices bleed at a rate less than or equal to 6 scfh.⁷⁷

In support of the development of the 2012 NSPS and 2016 NSPS, and this CTG, we consulted information in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic devices, subpart W of the GHGRP, the GHG Inventory, as well as pneumatic controller vendor information used during the development of the 2012 NSPS.⁷⁸ The data obtained from vendors included emission rates, costs, and any other pertinent information for each pneumatic controller model (or model family). All pneumatic controllers that a vendor offered were itemized and inquiries were made into the specifications of each device and whether it was applicable to oil and natural gas operations. High-bleed and low-bleed devices were differentiated using the 6 scfh threshold.

Although, by definition, a low-bleed device can emit up to 6 scfh, through vendor research, a typical low-bleed device available currently on the market emits lower than the maximum rate allocated for the device type. Specifically, low-bleed devices on the market today have bleed rates from 0.2 scfh up to 5 scfh. Similarly, the available bleed rates for a high-bleed device vary significantly from venting as low as 7 scfh to as high as 100 scfh.^{79,80} While the vendor data provided useful information on specific makes and models, it did not yield sufficient information about the prevalence of each model type in the population of devices in the oil and

⁷⁷ The classification of high-bleed and low-bleed devices originated from a report by Pacific Gas & Electric (PG&E) and the Gas Research Institute (GRI) in 1990 titled “Unaccounted for Gas Project Summary Volume.” This classification was adopted for the October 1993 Report to Congress titled “Opportunities to Reduce Anthropogenic Methane Emissions in the United States”. As described on page 2-16 of the report, “devices with emissions or ‘bleed rates’ of 0.1 to 0.5 cubic feet per minute are considered to be ‘high-bleed’ types (PG&E 1990).” This range of bleed rates is equivalent to 6 to 30 cubic feet per hour.

⁷⁸ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution – Background Technical Support Document for Proposed Standards*. July 2011. EPA Document Number EPA-453/R-11-002.

⁷⁹ U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC. November 2010.

⁸⁰ All rates are listed at an assumed supply gas pressure of 20 psig.

natural industry, which is an important factor in developing a representative emission factor. Therefore, in support of this CTG, we have determined that the best available emission estimates for pneumatic controllers in the production segment are from the GHGRP. For the natural gas processing segment, we determined that the quantified representative methane emissions from a continuous bleed pneumatic controller based on natural gas emission rates presented in Volume 12 of the EPA/GRI report used in the 2012 NSPS TSD is the best available emissions information.⁸¹

The basic approach used for this analysis of emissions from pneumatic controllers was to first approximate the natural gas emissions from an average high-bleed and low-bleed pneumatic controller in the production and processing segments and then estimate methane and VOC emissions using a representative gas composition from the 2011 Gas Composition Memorandum. A bleed rate of 1.39 scfh was used for a low-bleed controller, and a bleed rate of 37.3 scfh was used for a high-bleed controller. The specific gas composition ratio used for the production and processing segments was 0.278 pounds VOC per pound methane. Table 6-2 summarizes the estimated bleed emissions for a representative pneumatic controller by industry segment (for production and processing segments) and device type.

Table 6-2. Average Emission Rates for High-Bleed and Low-Bleed Pneumatic Controllers in the Oil and Natural Gas Industry^a

Industry Segment	High-Bleed (tpy)		Low-Bleed (tpy)	
	Methane	VOC	Methane	VOC
Oil and Natural Gas Production ^{b,c}	5.3	1.47	0.2	0.06
Natural Gas Processing ^d	1.00	0.28	1.0	0.28

^a The conversion factor used in this analysis is 1 Mcf of methane is equal to 0.0208 tons methane.

^b Natural gas production methane emissions are derived from the GHGRP (subpart W).

^c Oil production methane emissions are derived from the GHGRP (subpart W). It is assumed only continuous bleed devices are used in oil production.

^d Natural gas processing segment methane emissions are derived from Volume 12 of the 1996 EPA/GRI report. Emissions from devices in the processing segment were determined based on data available for snap-acting and continuous bleed devices. Further distinction between high-

⁸¹ GRI/EPA Research and Development. Methane Emissions from the Natural Gas Industry; Volume 12: Pneumatic Devices. (1996) EPA-600/R-96-0801. Table 4-11, page 56.

and low-bleed could not be determined based on available data. For the natural gas processing segment, it is assumed that existing natural gas plants have already replaced pneumatic controllers with other types of controls (i.e., an instrument air system) and any high-bleed devices that remain are safety related.

For the natural gas processing segment, this analysis assumes that existing natural gas plants have already replaced pneumatic controllers with other types of controls (i.e., an instrument air system) and any high-bleed devices that remain are safety related.

6.3 Available Controls and Regulatory Approaches

6.3.1 Available VOC Emission Control Options

Although pneumatic controllers have relatively small emissions individually, due to the large population of these devices, the cumulative VOC emissions for the industry are significant. We are not aware of any add-on controls that are or can be used to reduce VOC emissions from gas-driven pneumatic controllers. The following sections provide a summary of options for reducing VOC emissions from pneumatic controllers including: (1) replacing high-bleed controllers with low-bleed controllers or zero-bleed controllers; (2) driving controllers with instrument air rather than natural gas, using non-gas-driven controllers; and (3) enhanced maintenance.

Sections 6.3.1.1 and 6.3.1.2 discuss the control of VOC emissions by replacing a high-bleed device with a low-bleed device, and driving controllers with instrument air rather than natural gas, including the estimated costs of these options. Given applicability, efficiency and the expected costs, other options (i.e., mechanical controls and enhanced maintenance) are only briefly discussed in sections 6.3.1.3 and 6.3.1.4.

6.3.1.1 *Install a Low-Bleed Device in Place of a High-Bleed Device*

Description

As discussed previously, low-bleed controllers generally provide the same operational function as a high-bleed controller, but have lower continuous bleed emissions.

Control Effectiveness

We estimate on average that 1.41 tons of VOC will be reduced annually per device in the production segment from installing a low-bleed device in place of a high-bleed device. There are certain situations in which replacing and retrofitting devices are not feasible, such as instances where a minimal response time is needed, cases where large valves require a high-bleed rate to

actuate, or a safety isolation valve is involved. Based on criteria provided by the Natural Gas STAR Program, we assumed about 80 percent of high-bleed devices can be replaced with low-bleed devices throughout the production segment.

Applicability of low-bleed controllers may depend on the function carried out by the controller. Low-bleed pneumatic controllers may not be applicable for replacement of high-bleed devices because a process condition may require a fast or precise control response to minimize deviation from the desired set point. A slower acting low-bleed controller could potentially result in damage to equipment and/or become a safety issue because it may not be able to respond as quickly as a high-bleed controller. An example of this is a compressor where pneumatic controllers may monitor the suction and discharge pressure and actuate a recycle when one or the other is out of the specified target range. Other scenarios for fast and precise control include transient (non-steady state) situations where a gas flow rate may fluctuate widely or unpredictably. This situation requires a responsive high-bleed device to ensure that the gas flow can be controlled in all situations. Temperature and level controllers are typically present in control situations that are not prone to fluctuate as widely or where the fluctuation can be readily and safely accommodated by the equipment. Therefore, such processes can typically accommodate control from a low-bleed device, which is slower acting and less precise.

Cost Impacts

Costs were based on vendor research as a result of updating and expanding upon the information given in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic controllers.⁸² As Table 6-3 indicates, the average cost for a low-bleed pneumatic controller is \$2,698, while the average cost for a high-bleed pneumatic controller is \$2,471.⁸³ In order to analyze cost impacts, the average cost to install a new low-bleed pneumatic controller was annualized for a 15-year period using a 7 percent interest rate. This equates to an annualized cost of around \$271 per low-bleed device for the production segment.

⁸² U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

⁸³ Costs are estimated in 2012 U.S. dollars.

Table 6-3. Cost Projections for Representative Pneumatic Controllers^a

Device	Minimum Cost (\$2012)	Maximum Cost (\$2012)	Average Cost (\$2012)
High-Bleed Controller	\$387	\$7,398	\$2,471
Low-Bleed Controller	\$554	\$9,356	\$2,698

^a 2011 NSPS TSD 2008 dollars converted to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflator (5.69 percent). During the development of the 2012 NSPS, major pneumatic controller vendors were surveyed for costs, emission rates and any other pertinent information.

Monetary savings associated with retaining natural gas that would have been emitted was estimated based on a natural gas value of \$4.00 per Mcf.⁸⁴ The use of a low-bleed pneumatic controller is estimated to reduce methane emissions by 5.1 tpy (245 Mcf/yr) (using the conversion factor of 0.0208 tons methane per 1 Mcf) over the use of a high-bleed pneumatic controller. Assuming natural gas in the production segment is 82.8 percent methane by volume, this equals 296 Mcf natural gas recovered per year. Therefore, the value of recovered natural gas from one pneumatic controller in the production segment is approximately \$1,184. Table 6-4 presents the estimated cost of control per ton of VOC reduced for replacing a high-bleed pneumatic controller with a new low-bleed pneumatic controller in the production segment of the oil and natural gas industry.

Table 6-4. VOC Cost of Control for Replacing an Existing High-Bleed Pneumatic Controller with a New Low-Bleed Pneumatic Controller

Segment	Average Capital Cost per Unit (\$2012) ^{a,c}	Total Annual Costs per Unit (\$2012/yr) ^{b,c}		VOC Cost of Control (\$2012/ton) ^c	
		Without Savings	With Savings	Without Savings	With Savings
Oil and Natural Gas Production	\$2,698	\$296	(\$886)	\$209	(\$625)

^a Average capital cost of a low-bleed device as summarized in Table 6-3.

^b Annualized cost assume a 7 percent interest rate over a 15-year equipment lifetime.

^c Cost data from the 2011 TSD converted to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflator (5.69 percent).

⁸⁴ U.S. Energy Information Administration. *Annual U.S. Natural Gas Wellhead Price*. U.S. Energy Information Administration. *Natural Gas Navigator*. Retrieved online on 12 Dec 2010 at <http://www.eia.doe.gov/dnav/ng/hist/n9190us3a.htm>.

6.3.1.2 *Instrument Air Systems*

Description

The major components of an instrument air conversion project include the compressor, power source, dehydrator and volume tank. The following is a description of each component as described in the Natural Gas STAR document, “Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air”:⁸⁵

- (1) Compressors used for instrument air delivery are available in various types and sizes, from centrifugal (rotary screw) compressors to reciprocating piston (positive displacement) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system, and the typical bleed rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank. For reliability, a full spare compressor is normally installed. A minimum amount of electrical service is required to power the compressors.
- (2) A critical component of the instrument air control system is the power source required to operate the compressor. Since high-pressure natural gas is abundant and readily available, natural gas pneumatic systems can run uninterrupted on a 24-hour, 7-day per week schedule. The reliability of an instrument air system, however, depends on the reliability of the compressor and electric power supply. Most large natural gas plants have either an existing electric power supply or have their own power generation system. For smaller facilities and in remote locations, however, a reliable source of electric power can be difficult to ensure. In some instances, solar-powered, battery-operated air compressors can be cost-effective for remote locations, and reduce both VOC emissions and energy consumption. Small natural gas-driven fuel cells are also being developed.
- (3) Dehydrators, or air dryers, are also an integral part of the instrument air compressor system. Water vapor present in atmospheric air condenses when the air is pressurized and cooled, and can cause a number of problems to these systems, including corrosion of the instrument parts and blockage of instrument air piping and controller orifices.

⁸⁵ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. 2006.

- (4) The volume tank holds enough air to allow the pneumatic control system to have an uninterrupted supply of high-pressure air without having to run the air compressor continuously. The volume tank allows a large withdrawal of compressed air for a short time, such as for a motor starter, pneumatic pump, or pneumatic tools without affecting the process control functions.

Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic controller. The use of instrument air eliminates natural gas emissions from natural gas-driven pneumatic controllers. All other parts of a natural gas pneumatic system will operate the same way with instrument air as they do with natural gas. The conversion of natural gas pneumatic controllers to instrument air systems is applicable to all natural gas facilities with electrical service available. Figure 6-1 illustrates a diagram of a natural gas pneumatic control system. Figure 6-2 illustrates a diagram of a compressed instrument air control system.⁸⁶

Control Effectiveness

The use of instrument air eliminates natural gas emissions from the pneumatic controllers; however, the system is only applicable in locations with access to a sufficient and consistent supply of electrical power. Instrument air systems are also usually installed at facilities where there is access to high Btu gas, a high concentration of pneumatic control valves and the presence of an operator who can ensure the system is properly functioning.⁸⁷

For natural gas processing plants, we believe that instrument air systems are typically used to power pneumatic controllers and that any natural gas-driven pneumatic controllers in use are required for safety and functional reasons. The use of an instrument air system would reduce VOC emissions from a natural gas-driven pneumatic controller by 100 percent.

Cost Impacts

Instrument air conversion requires additional equipment to properly compress and control the pressurized air. The size of the compressor depends on the number of control loops present at a location. A control loop consists of one pneumatic controller and one control valve. The volume of compressed air supply for the pneumatic system is equivalent to the volume of gas

⁸⁶ Ibid.

⁸⁷ Ibid.

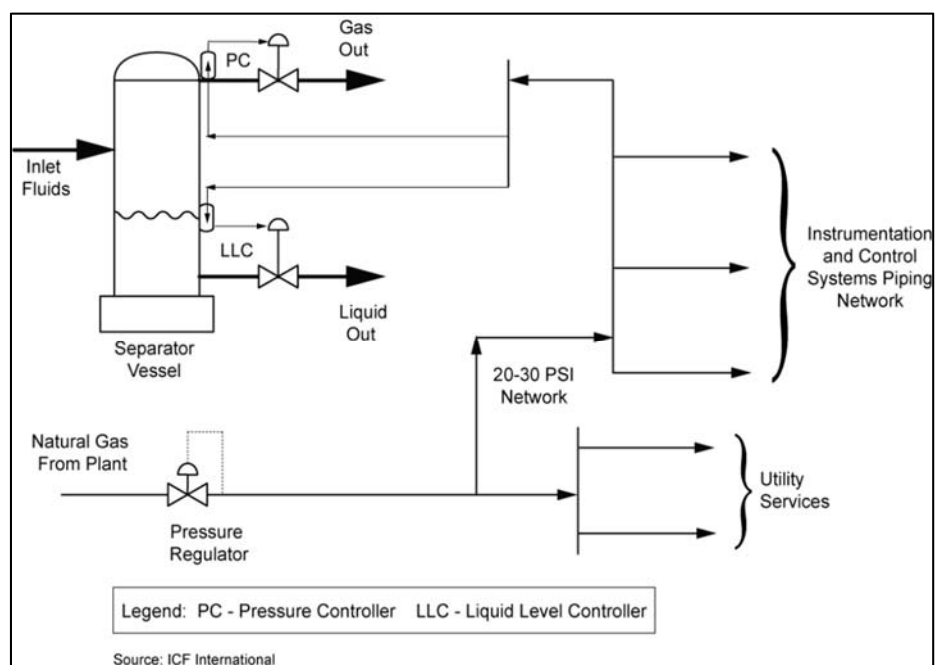


Figure 6-1. Natural Gas Pneumatic Control System

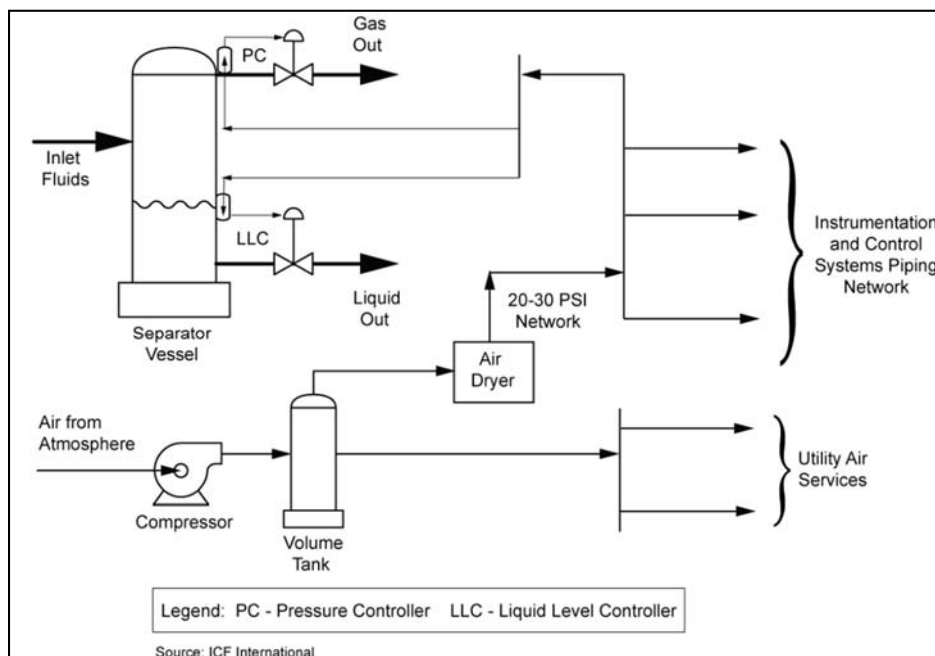


Figure 6-2. Compressed Instrument Air Control System

used to run the existing instrumentation, adjusted for air losses during the drying process. The current volume of gas usage can be determined by direct metering if a meter is installed. Otherwise, an alternative rule of thumb for sizing instrument air systems is one cubic foot per minute (cfm) of instrument air for each control loop. As the system is powered by electric compressors, the system requires a constant source of electrical power and a backup system to operate the controllers in the event of interruption of the electrical supply. Table 6-5 outlines three different sized instrument air systems including the compressor power requirements, the flow rate provided from the compressor, and the associated number of control loops.

Table 6-5. Compressor Power Requirements and Costs for Representative Instrument Air Systems^a

Compressor Power Requirements ^b			Flow Rate (cfm)	Control Loops (Loops/Compressor)	Power Costs (\$/yr)
Size of Unit	Hp	kW			
Small	10	13.3	30	15	\$7,758
Medium	30	40	125	63	\$23,332
Large	75	100	350	175	\$58,329

^a Based on rules of thumb stated in the Natural Gas STAR document, *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air*. Natural Gas STAR Program. Washington, DC. 2006.

^b Power is based on the operation of two compressors operating in parallel (each assumed to be operating at full capacity 50 percent of the year).

The primary costs associated with conversion to instrument air systems are the initial capital expenditures for installing compressors and the related equipment and operating costs for electrical energy to power the compressor motor. This equipment includes a compressor, a power source, a dehydrator, gas supply piping, control instruments, valve actuators and a storage vessel. The total cost, including installation and labor, of three representative sizes of compressors were evaluated based on assumptions found in the Natural Gas STAR document, “Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air” and are summarized in Table 6-6.⁸⁸

⁸⁸ Ibid.

Table 6-6. Estimated Capital and Annual Costs of Representative Instrument Air Systems (\$2012)

Instrument Air System Size	Compressor	Tank	Air Dryer	Total Capital Cost^a	Annualized Capital Cost^b	Labor Cost	Total Annual Cost^c	Annualized Cost of Instrument Air System
Small	\$3,987	\$797	\$2,391	\$17,938	\$2,554	\$1,410	\$9,168	\$11,722
Medium	\$19,928	\$2,391	\$7,173	\$77,716	\$11,065	\$4,580	\$27,912	\$38,977
Large	\$35,071	\$4,783	\$15,941	\$143,476	\$20,428	\$6,340	\$64,669	\$85,097

^a Total Capital Cost includes the cost for two compressors, two tanks, an air dryer and installation. Installation costs are assumed to be equal to 1.5 times the cost of capital. Equipment costs were derived from the 2012 NSPS TSD.

^b These costs have been converted to 2012 dollars (from 2008 dollars) using the Federal Reserve Economic Data GDP Price Deflator (Change in GDP: Implicit Price Deflator from 2008 to 2012 (5.69 percent)).⁸⁹

^c The annualized cost was estimated using a 7 percent interest rate and 10-year equipment life. Annual cost includes the cost of electrical power, as listed in Table 6-5, and labor.

⁸⁹ U.S. Bureau of Economic Analysis. *Gross Domestic Product: Implicit Price Deflator (GDPDEF)*, retrieved from FRED, Federal Reserve Bank of St. Louis. <https://research.stlouisfed.org/fred2/series/GDPDEF/> March, 26, 2015.

For new natural gas processing plants, the cost-effectiveness of the three representative instrument air system sizes was evaluated in the 2015 NSPS Proposal TSD based on the emissions mitigated from the number of control loops the system can provide and not on a per device basis. This approach was chosen because we assume new processing plants will need to provide instrumentation for multiple control loops and size the instrument air system accordingly. Table 6-7 summarizes the natural gas processing segment cost of control per ton of VOC reduced for three sizes of representative instrument air systems. For existing natural gas processing plants, it is our understanding that these plants have already upgraded to instrument air unless the function has a specific need for a high-bleed pneumatic controller, which would most likely be safety related. The cost of converting the pneumatic controllers to instrument air includes the capital cost of \$2,000 for the ductwork and annual cost of \$285 (assuming a 10-year equipment life at 7 percent interest). The VOC cost of control for converting pneumatic controllers to instrument air for processing plants that already have instrument air ranges from \$6 to \$68 per ton of VOC removed, depending on the size of the instrument air system.

For natural gas processing, the cost of control of the three representative instrument air systems was evaluated based on the emissions mitigated from the number of control loops the system can provide and not on a per controller basis. This approach was chosen because we assume new processing plants will need to provide instrumentation for multiple control loops and size the instrument air system accordingly. We also assume that existing processing plants have already upgraded to instrument air unless the function has a specific need for a high-bleed pneumatic controller, which would most likely be safety related. Table 6-7 summarizes the natural gas processing segment cost of control per ton of VOC reduced for three sizes of representative instrument air systems.

Table 6-7. Cost of Control of Representative Instrument Air Systems in the Natural Gas Processing Segment (\$2012)

System Size	Number of Control Loops	VOC Annual Emission Reduction (tpy) ^a	Value of Product Recovered (\$2012/year) ^b	Annualized Cost of System		VOC Cost of Control (\$2012/ton)	
				Without Savings	With Savings	Without Savings	With Savings
Small	15	4.18	\$3,485	\$11,722	\$8,236	\$2,804	\$1,970
Medium	63	17.5	\$14,592	\$38,977	\$24,385	\$2,227	\$1,393
Large	175	48.7	\$40,606	\$85,097	\$44,490	\$1,747	\$914

^a Based on the emissions mitigated from the entire system, which includes multiple control loops.

^b Value of recovered product assumes natural gas processing is 82.9 percent methane by volume. A natural gas price of \$4 per Mcf was assumed.

6.3.1.3 *Electrically Powered Systems in Place of Bleed Devices*

Description

Mechanical controls have been widely used in the oil and natural gas industry. They operate using a combination of levers, hand wheels, springs and flow channels with the most common mechanical control device being a liquid-level float to the drain valve position with mechanical linkages.⁹⁰ Another device that is increasing in use is electrically powered controls. Small electrical motors (including solar powered) have been used to operate valves and have no VOC emissions. Solar-powered control systems are driven by solar-power cells that actuate mechanical devices using electric power. As such, solar cells require some type of backup power or storage to ensure reliability.

Control Effectiveness⁹¹

Application of mechanical controls is limited because the control must be located in close proximity to the process measurement. Mechanical systems may have difficulty handling larger flow fluctuations. Electrically powered valves are only reliable with a constant supply of electricity. These controllers can achieve a 100 percent reduction in VOC emissions where applicable.

Cost Impacts

Depending on supply of power, mechanical and solar-power system costs can range from below \$1,000 to \$10,000 for an entire system.⁹²

⁹⁰ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

⁹¹ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

⁹² U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

6.3.1.4 *Enhanced Maintenance of Natural Gas-Driven Pneumatic Controllers*

Manufacturers of pneumatic controllers indicate that emissions in the field can be higher than the reported gas consumption due to operating conditions, age and wear of the device.⁹³

Examples of circumstances or factors that can contribute to this increase include:^{94,95}

- (1) Nozzle corrosion resulting in more flow through a larger opening;
- (2) Broken or worn diaphragms, springs (e.g., spring broken that holds the supply pilot plug on its seat), bellows, fittings (e.g., leaking tubing/tubing-fittings) and nozzles;
- (3) Corrosives in the gas leading to erosion and corrosion of control loop internals;
- (4) Improper installation;
- (5) Lack of maintenance (maintenance includes replacement of the filter used to remove debris from the supply gas and replacement of O-rings and/or seals);
- (6) Lack of calibration of the controller or adjustment of the distance between the flapper and nozzle;
- (7) Foreign material lodged in the pilot seat;
- (8) Debris/deposits on vent pilot plug. Material on the vent pilot can allow the controller to exhaust gas during the activation cycle;
- (9) Debris/deposits on the supply pilot plug. Material on the supply pilot can cause the introduction of gas while the vent is open; or
- (10) Wear in the seal seat.

The EPA prepared a white paper titled “Oil and Natural Gas Sector Pneumatic Devices,” in 2014, requesting specific comment on available emissions data for pneumatic devices. One of the comments received regarding data presented in “Measurements of Methane Emissions at Natural Gas Production Sites in the United States”⁹⁶ was that the data set reported was dominated by extreme values. The commenter noted that the highest emitting controllers are simply controllers emitting at a large rate, regardless of their service or design type. These

⁹³ Ibid.

⁹⁴ Ibid.

⁹⁵ American Petroleum Institute (API). *Pneumatic Controllers*. Webinar Prepared and Presented to the U.S. Environmental Protection Agency. March 25, 2014.

⁹⁶ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Pneumatic Devices. Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel* Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at <http://www.epa.gov/airquality/oilandgas/2014papers/20140415pneumatic.pdf>.

controllers can have high emissions because of factors, other than design, related to maintenance, malfunction, or defect.⁹⁷

Maintenance of pneumatics can correct many of these problems and can be an effective method for reducing emissions. Cleaning and tuning, in addition to repairing leaking gaskets, tubing fittings, and seals, can save 5 to 10 scfh per device. Eliminating unnecessary valve positioners can save up to 18 scfh per device.⁹⁸

6.3.2 Existing Federal, State and Local Regulations

6.3.2.1 *Federal Regulations that Specifically Require Control of VOC Emissions*

Under the 2012 NSPS and 2016 NSPS, new or modified continuous bleed natural gas-driven pneumatic controllers at natural gas processing plants are subject to a VOC emission limit of zero (equivalent to non-natural gas-driven pneumatic controllers). Continuous bleed natural gas-driven pneumatic controllers in the production segment must have a bleed rate of 6 scfh or less.

6.3.2.2 *State and Local Regulations that Specifically Require Control of VOC Emissions*

States may have permitting restrictions on VOC emissions that apply to an emissions source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met and, often, how the source must be operated. To ensure that sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

For pneumatic controllers, Colorado and Wyoming have existing control requirements similar to those required under the 2012 NSPS and 2016 NSPS. Other states have permitting and

⁹⁷ Allen, David. Comments Provided to the EPA on *Oil and Natural Gas Sector Pneumatic Devices-Peer Review Document*. University of Texas at Austin. June 2014.

⁹⁸ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

registration rules for controlling fugitive VOC emissions (which would include non-bleed emissions from pneumatic controllers).

Colorado requires that no- or low-bleed pneumatic controllers with a bleed rate of 6 scfh or less be installed for all new and existing applications (unless approved for use due to safety and/or process purposes) statewide (Regulation 7, XVIII.C.2). Where technically and economically feasible, Colorado requires no-bleed pneumatic controllers at facilities that are connected to the electric grid and using electricity to power equipment.

Wyoming requires the installation of low- or no-bleed pneumatic controllers with a bleed rate of 6 scfh or less at all new facilities. Upon modification of facilities, new pneumatic controllers must be low- or no-bleed and existing controllers must be replaced with no- or low-bleed controllers (at well site facilities only and not at natural gas processing plants).

Although some local rule requirements do not specifically require the control of VOC emissions from pneumatic controllers, local permit requirements (such as those required by the Bay Area Air Quality Management District) may require that a permit to operate applicant provide the number of high-bleed and low-bleed pneumatic devices in a permit application. Under some situations where facilities use high-bleed devices, the permitting authority might require an owner or operator to provide device-specific bleed rates and supporting documentation for each high-bleed device. In cases where high-bleed devices must be used, the permitting authority may require that the facility conduct fugitive monitoring and/or implement control requirements under conditions of their permit to operate.⁹⁹

6.4 Recommended RACT Level of Control

Sections 6.4.1 and 6.4.2 present the recommended RACT level of control for continuous bleed natural gas-driven pneumatic controllers located at natural gas processing plants and continuous bleed natural gas-driven pneumatic controllers located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline.

⁹⁹ Cheng, Jimmy. *Permit Handbook. Chapter 3.5 Natural Gas Facilities and Crude Oil Facilities*. Bay Area Air Quality Management District. September 16, 2013.

6.4.1 Continuous Bleed Natural Gas-Driven Pneumatic Controllers Located at a Natural Gas Processing Plant

Based on our evaluation of available data obtained in the development of the 2012 NSPS and 2016 NSPS, peer review comments received on the “Oil and Natural Gas Sector Pneumatic Devices” white paper, and existing regulations that control VOC emissions from pneumatic controllers, we recommend that VOC emissions from an individual continuous bleed natural gas-driven pneumatic controller located at a natural gas processing plant be controlled by RACT. As noted in section 6.3.2, both Colorado and Wyoming require either low- or no-bleed controllers (where a high-bleed controller is defined as emitting at least 6 scfh); and the 2012 NSPS and 2016 NSPS require that new and modified individual continuous bleed pneumatic controllers at natural gas processing plants have a natural gas bleed rate of 0 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 0 scfh). For existing individual continuous bleed pneumatic controllers at natural gas processing plants, our RACT recommendation is that controllers have a natural gas bleed rate of 0 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 0 scfh). Our rationale for selecting a natural gas bleed rate of 0 scfh (with functional and safety exceptions) for our recommended RACT is based on the ability of most natural gas processing plants to install and utilize an instrument air system. As discussed in section 6.3.1.2 of this chapter, by using an instrument air system, compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic controller. Therefore, the use of instrument air eliminates natural gas and VOC emissions from pneumatic controllers and supports a natural gas bleed rate of 0 scfh.

In order to meet an emission limit of 0 scfh, natural gas processing plants would likely need to use an instrument air system. The use of instrument air eliminates natural gas and VOC emissions from natural gas-driven pneumatic controllers. We believe that most natural gas processing plants already meet the recommended RACT level of control by driving controllers with instrument air or other non-gas-driven controls unless there is a specific need for a high-bleed pneumatic controller. Nonetheless, for those natural gas processing plants that do not have an installed instrument air system, the cost of control of installing three representative instrument air systems was evaluated under the 2012 NSPS and 2016 NSPS based on the emissions

mitigated from the number of control loops the system can provide (see section 6.3.1.2 of this chapter). Based on this analysis, the cost of this option was considered to be reasonable for natural gas processing plants (see Table 6-7 of section 6.3.1.2 of this chapter). The cost of control per ton of VOC reduced was estimated at \$1,700 - \$2,800 without savings and \$910 - \$2,000 with savings. For determining potential cost impacts, a major assumption made was that processing plants are constructed at locations with sufficient electrical service to power the instrument air compression systems.

In summary, we recommend the following RACT for each continuous bleed natural gas-driven pneumatic controller located at a natural gas processing plant:

RACT for Each Continuous Bleed Natural Gas-Driven Pneumatic Controller Located at a Natural Gas Processing Plant:¹⁰⁰ Each continuous bleed natural gas driven pneumatic controller located at a natural gas processing plant must have a natural gas bleed rate of 0 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 0 scfh).

6.4.2 Continuous Bleed Natural Gas-Driven Pneumatic Controllers Located from the Wellhead to the Natural Gas Processing Plant or Point of Custody Transfer to an Oil Pipeline

Based on our evaluation of available data obtained in the development of the 2012 NSPS and 2016 NSPS, peer review comments received on the “Oil and Natural Gas Sector Pneumatic Devices” white paper, and existing regulations that control VOC emissions from pneumatic controllers, we are recommending a natural gas bleed rate less than or equal to 6 scfh with limited exceptions described below as the RACT for controlling VOC emissions from continuous bleed natural gas-driven pneumatic controllers located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline. We are also recommending that no requirements apply under RACT for pneumatic controllers that have a natural gas bleed rate less than or equal to 6 scfh that are located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline.

¹⁰⁰ In the NSPS, we excluded from the NSPS affected facility status non-natural gas-driven pneumatic controllers located at natural gas processing plants. Natural gas-driven controllers exempt from the zero VOC emission standard under the functional needs exclusion would still be affected facilities and would have certain tagging, recordkeeping and reporting requirements.

As indicated in section 6.2.2 of this chapter, low-bleed pneumatic controllers can emit up to 6 scfh. Both Colorado and Wyoming conditionally require either low- or no-bleed controllers (where a high-bleed controller is defined as emitting greater than 6 scfh); and the 2012 NSPS and 2016 NSPS require that new and modified individual continuous bleed pneumatic controllers have a bleed rate of 6 scfh or less (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 6 scfh). For purposes of this CTG, and consistent with the definition of high-bleed controller used for the 2012 NSPS, 2016 NSPS, and both the Wyoming and Colorado state regulations, a high-bleed pneumatic device is defined as emitting greater than 6 scfh to the atmosphere.

Although both Wyoming and Colorado specifically require low-bleed or no-bleed pneumatic controllers in place of high-bleed controllers (where technically and economically feasible), we are recommending a RACT emission limit of 6 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 6 scfh) apply to each continuous bleed pneumatic controller. This approach allows flexibility in how a source chooses to limit VOC emissions from an applicable individual pneumatic controller and acknowledges that there may be circumstances where it is not practical to meet a 6 scfh limit. By requiring a limit be met, facilities have the option of controlling emissions by one or more options presented in section 6.3.1 of this chapter (e.g., replace a high-bleed device with a low-bleed device and implement enhanced monitoring to mitigate increased VOC emissions from poor maintenance/poor operation) depending on site-specific circumstances. We are including this flexibility in our recommended RACT to address the varied control options and applicability issues (e.g., instrument air systems require access to electrical power or a backup pneumatic controller and access to electric power or backup pneumatic controllers may not be available in remote locations) presented in section 6.3.1 of this chapter.

Although facilities would have flexibility in how they meet the recommended RACT level of control, by establishing an emission limit equal to the design bleed rate for a low-bleed device (6 scfh), we believe that most facilities would likely replace high-bleed controllers with low-bleed controllers (it is assumed about 80 percent of high-bleed devices can be replaced with

low-bleed devices).¹⁰¹ For the production segment, we estimated that, on average, 1.41 tons of VOC would be reduced annually per device in the production segment from installing a low-bleed device in place of a high-bleed device.

As presented in section 6.3.1.1 of this chapter, the cost of replacing a high-bleed device with a new low-bleed device is on the order of \$2,698 per device, and the cost of control in the production segment is estimated to be \$210 per ton of VOC emissions reduced without savings. Considering the cost savings of gas recovered from installing a low-bleed device in place of a high-bleed device, it is estimated that there would be an overall net savings.

In summary, we recommend the following RACT for each single continuous bleed natural gas-driven pneumatic controller located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline:

RACT for Each Single Continuous Bleed Natural Gas-Driven Pneumatic Controller Located from the Wellhead to the Natural Gas Processing Plant or Point of Custody Transfer to an Oil Pipeline: Each pneumatic controller, which is a single continuous bleed natural gas-driven pneumatic controller¹⁰² must have a natural gas bleed rate less than or equal to 6 scfh (unless there are functional needs including, but not limited to response time, safety and positive actuation, requiring a bleed rate greater than 6 scfh).

¹⁰¹ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

¹⁰² In the NSPS, we excluded from NSPS pneumatic controller affected facility status continuous bleed natural gas-driven pneumatic controllers with a bleed rate not greater than 6 scfh (low-bleed controllers) located in the production segment. Continuous bleed natural gas-driven controllers exempt from the 6 scfh bleed rate emission standard under the functional needs exclusion would still be affected facilities and would have certain tagging, recordkeeping and reporting requirements.

6.5 Factors to Consider in Developing Pneumatic Controller Compliance Procedures

6.5.1 Oil and Natural Gas Production (Individual Continuous Bleed Pneumatic Controller with a Natural Gas Bleed Rate Greater than 6 scfh Located from the Wellhead to the Natural Gas Processing Plant or Point of Custody Transfer to an Oil Pipeline)

To ensure that each continuous bleed natural gas-driven pneumatic controller located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline is operated with a natural gas bleed rate less than or equal to 6 scfh (the recommended RACT level of control), we recommend that regulating agencies specify operating, recordkeeping and reporting requirements to document compliance. It is recommended that air agencies require that each pneumatic controller be tagged with the month and year of installation and identification information that allows traceability to manufacturer's documentation.

It is recommended that air agencies require owners and operators of continuous bleed natural gas-driven pneumatic controllers that are subject to RACT maintain records that: (1) document the location and manufacturer's specifications of each pneumatic controller; (2) if applicable, provide a demonstration as to why the use of a pneumatic controller with a natural gas bleed rate greater than 6 scfh is required (the recommended RACT level of control); and (3) document deviations in cases where a pneumatic controller was not operated in compliance with RACT.

It is also recommended that air agencies require owners and operators to submit annual reports that include (1) if applicable, documentation that the use of a pneumatic controller with a natural gas bleed rate greater than 6 standard cubic feet per hour is required and the reasons why; and (2) the records of deviations that occurred during the reporting period.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

6.5.2 Natural Gas Processing Segment (Individual Continuous Bleed Natural Gas-Driven Pneumatic Controller Located at a Natural Gas Processing Plant)

To ensure each continuous bleed natural gas-driven pneumatic controller at natural gas processing plants is operated with a natural gas bleed rate of zero (the recommended RACT level of control), we suggest that air agencies specify operating, recordkeeping and reporting requirements to document compliance. We also suggest that air agencies require that each pneumatic controller be tagged with the month and year of installation and identification information that allows traceability to the manufacturer's documentation. It is recommended that air agencies require owners and operators of pneumatic controllers maintain records that:

- (1) document the location and manufacturer's specifications of each pneumatic controller;
- (2) document that the natural gas bleed rate is zero; and (3) document deviations in cases where a pneumatic controller was not operated in compliance with RACT.

It is also recommended that air agencies require owners and operators to submit annual reports that include the records of deviations that occurred during the reporting period.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

7.0 PNEUMATIC PUMPS

The oil and natural gas industry uses a variety of pneumatic gas-driven pumps where there is no reliable electrical power to “control processing problems and protect equipment.”¹⁰³ Pneumatic pumps are “small positive displacement, reciprocating units used throughout the oil and natural gas industry to inject precise amounts of chemicals into process streams or for freeze protection glycol circulation.”¹⁰⁴ Most chemical injection pumps fall into two main types: (1) diaphragm pumps, generally used for heat tracing; or (2) plunger/piston, generally used for chemical and methanol injection. Pneumatic pumps driven by natural gas emit natural gas, which contains VOC. Other types of pneumatic pumps may be driven by gases other than natural gas and, therefore, do not emit VOC. The focus of this CTG is natural gas-driven pneumatic pumps. This chapter provides a description of pneumatic pumps that are used in the oil and natural gas industry, including their function and associated emissions. This chapter also provides control techniques used to reduce VOC emissions from pneumatic pumps, along with costs and emission reductions. Finally, this chapter provides a discussion of our recommended RACT for pneumatic pumps and the associated VOC emission reductions and costs.

7.1 Applicability

For the purposes of this CTG, a pneumatic pump is a positive displacement reciprocating unit used for injecting precise amounts of chemicals into a process stream or for glycol circulation. The pneumatic pump may use natural gas or another gas to drive the pump. The emissions and emission control options discussed herein would apply to natural gas-driven chemical/methanol and diaphragm pumps located at natural gas processing plants and well sites.

¹⁰³ U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 13: Chemical Injection Pumps*. EPA-600/R-96-080b. June 1996.

¹⁰⁴ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

7.2 Process Description and Emission Sources

7.2.1 Process Description

As noted above, pneumatic pumps are “positive displacement, reciprocating units used for injecting precise amounts of chemicals into a process stream or for glycol circulation.”¹⁰⁵ Pneumatic pumps often make use of gas pressure where electricity is not readily available.¹⁰⁶ In the production segment, the supply gas is mostly produced natural gas, whereas in the processing segment, the supply gas may be compressed air. For natural gas-driven pneumatic pumps, characteristics that affect VOC emissions include the frequency of operation, the size of the unit, the supply gas pressure, and the inlet natural gas composition.¹⁰⁷

Pneumatic pumps are generally used for one of three purposes: glycol circulation in dehydrators, hot oil circulation for heat tracing/freeze protection, or chemical injection. Glycol dehydrator pumps may recover energy from the high-pressure rich glycol/gas mixture leaving the absorber and use that energy to pump the low-pressure lean glycol back into the absorber.¹⁰⁸ Diaphragm pumps are commonly used to circulate hot glycol or other heat-transfer fluids in tubing covered with insulation to prevent freezing in pipelines, vessels, and tanks. Chemical injection pumps (i.e., piston/plunger pumps or small diaphragm pumps) inject small amounts of chemicals, such as methanol, to prevent hydrate formation or corrosion inhibitors into process streams to regulate operations of a plant and protect the equipment.

Pneumatic pumps have two major components, a driver side and a motive side, which operate in the same manner but with different reciprocating mechanisms. Pressurized gas provides energy to the driver side of the pump, which operates a piston or flexible diaphragm to draw fluid into the pump. The motive side of the pump delivers the energy to the fluid being moved in order to discharge the fluid from the pump. The natural gas leaving the exhaust port of

¹⁰⁵ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

¹⁰⁶ Ibid.

¹⁰⁷ Ibid.

¹⁰⁸ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Pneumatic Devices. Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel*. Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at <http://www.epa.gov/airquality/oilandgas/2014papers/20140415pneumatic.pdf>.

the pump is either directly discharged into the atmosphere or is recovered and used as a fuel gas or stripping gas.¹⁰⁹

Chemical injection pumps are positive displacement, reciprocating units designed to inject precise amounts of chemical into a process stream. Positive displacement pumps work by allowing a fluid to flow into an enclosed cavity from a low-pressure source, trapping the fluid, and then forcing it out into a high-pressure receiver by decreasing the volume of the cavity. A complete reciprocating stroke includes two movements, referred to as an upward motion or suction stroke, and a downward motion or power stroke. During the suction stroke, the chemical is lifted through the suction check valve into the fluid cylinder. The suction check valve is forced open by the suction lift produced by the plunger and the head of the liquid being pumped. Simultaneously, the discharge check valve remains closed, thus allowing the chemical to remain in the fluid chamber. During the power stroke, the plunger assembly is forced downwards, immediately shutting off the suction check valve. Simultaneously, the chemical is displaced, forcing open the discharge check valve and allowing the fluid to be discharged.¹¹⁰

Typical chemicals injected in an oil or natural gas field are biocides, demulsifiers, clarifiers, corrosion inhibitors, scale inhibitors, hydrate inhibitors, paraffin dewaxers, surfactants, oxygen scavengers, and H₂S scavengers. These chemicals are normally injected at the wellhead and into gathering lines or at production separation facilities. Because the injection rates are typically small, the pumps are also small. They are often attached to barrels containing the chemical being injected.¹¹¹

Diaphragm pumps are positive displacement pumps, meaning they use contracting and expanding cavities to move fluids. Diaphragm pumps work by flexing the diaphragm out of the displacement chamber. When the diaphragm moves out, the volume of the pump chamber increases and causes the pressure within the chamber to decrease and draw in fluid. The inward stroke has the opposite effect, decreasing the volume and increasing the pressure of the chamber to move out fluid.¹¹²

¹⁰⁹ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

¹¹⁰ Ibid.

¹¹¹ Ibid.

¹¹² GlobalSpec. *Diaphragm Pumps Information*. Available online - http://www.globalspec.com/learnmore/flow_transfer_control/pumps/diaphragm_pumps.

Not all pneumatic pumps are natural gas driven. At sites without electrical service sufficient or reliable enough to power an instrument air compressor control system, mechanical or electrically powered pneumatic pumps may be used. Where reliable electrical service is available, sources of power other than pressurized natural gas, such as compressed instrument air may be used. Because these devices are not natural gas driven, they do not directly release natural gas or VOC emissions. Instrument air systems are feasible only at oil and natural gas industry locations where the devices can be driven by compressed instrument air systems and have electrical service sufficient and reliable enough to power a compressor. This analysis assumes that natural gas processing plants are likely to have electrical service sufficient to power an instrument air system, and that most existing gas processing plants use instrument air instead of natural gas-driven pumps.¹¹³ The application of electrical controls is discussed further in section 7.3 of this chapter.

7.2.2 Emissions Data

7.2.2.1 Summary of Major Studies and Emissions

In the evaluation of the emissions from pneumatic pumps and the potential options available to reduce these emissions, numerous studies were consulted. Table 7-1 lists these references with an indication of the type of relevant information contained in each reference. In addition to these sources, we evaluated the peer reviewer and public comments received on the EPA's white paper, "Oil and Natural Gas Sector Pneumatic Devices."¹¹⁴

¹¹³ U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices*. EPA-600/R-96-080k. June 1996.

¹¹⁴ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Pneumatic Devices. Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel*. Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at <http://www.epa.gov/airquality/oilandgas/2014papers/20140415pneumatic.pdf>.

Table 7-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options ^g
Greenhouse Gas Reporting Program ^a	EPA	2014	Nationwide	X	
Inventory of Greenhouse Gas Emissions and Sinks ^b	EPA	Annual	Nationwide/ Regional	X	
Methane Emissions from the Natural Gas Industry ^{c,d}	EPA/GRI	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry ^e	EPA	1999	Nationwide	X	
Natural Gas STAR Program ^f	EPA	2012	Study Specific	X	X

^a U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC. November 2014.

^b U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. <https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html>.

^c U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 2: Technical Report*. EPA-600/R-96-080b. June 1996; U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 3: General Methodology*. EPA-600/R-96-080c. June 1996.

^d U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 5: Activity Factors*. EPA-600/R-96-080e. June 1996; and U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices*. EPA-600/R-96-080k. June 1996.

^e U.S. Environmental Protection Agency. *Methane Emissions from the U.S. Petroleum Industry. Final Report*. Prepared for the U.S. Environmental Protection Agency by Radian International LLC. EPA-600/R-99-010. February 1999.

^f U.S. Environmental Protection Agency. *Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR. Washington, DC. October 2006.

^g An “X” in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

7.2.2.2 Representative Pneumatic Pump Emissions

For this analysis, we consulted information in the appendices of Natural Gas STAR lessons learned documents on pneumatic pumps,^{115,116} the GHGRP, the GHG Inventory, and

¹¹⁵ U.S. Environmental Protection Agency. *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas STAR. Washington, DC. October 2006.

¹¹⁶ U.S. Environmental Protection Agency. Pro Fact Sheet No. 301. *Convert Pneumatics to Mechanical Controls*. Office of Air and Radiation: Natural Gas STAR. Washington, DC. September 2004.

U.S. EPA/GRI Report.¹¹⁷ The GHGRP and GHG Inventory use emission factors from the U.S. EPA/GRI Report. Similarly, we determined that the best available emission factors for pneumatic pumps are presented in the U.S. EPA/GRI Report.

The basic approach used for this analysis was to first approximate methane emissions from the average pneumatic pump in the production and processing segments and then estimate VOC and HAP emissions using the gas composition factors from the 2011 Gas Composition Memorandum. The specific gas composition ratio used for this analysis was 0.278 lbs VOC per pound methane in the production and processing segment. Table 7-2 summarizes the estimated average emission factors for a representative pneumatic pump for the production and processing segments for both methane and VOC.

Table 7-2. Average Emission Estimates per Pneumatic Device

Segment/Pump Type	Emission Factor Methane (scf/day) ^a	Emission Factor Methane (Mcf/yr) ^b	Emission Factor Methane (tpy) ^c	Emission Factor VOC (tpy) ^d
Production				
Diaphragm	446	163	3.46	0.96
Piston	48.9	18	0.38	0.11
Processing				
Small Diaphragm	446	163	3.46	0.96
Medium Diaphragm	446	163	3.46	0.96
Large Diaphragm	446	163	3.46	0.96
Small Piston	48.9	18	0.38	0.11
Medium Piston	48.9	18	0.38	0.11
Large Piston	48.9	18	0.38	0.11

^a Data Source: EPA/GRI. *Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps*. June 1996 (EPA-600/R -96-080m), Sections 5.1 – Diaphragm Pumps and 5.2 – Piston Pumps.

^b Assumes 365 days/yr operation in natural gas production and processing.

^c Assumes density of methane is 19.26 g/scf.

^d Assumes 0.278 VOC content per pound of methane.

¹¹⁷ Gas Research Institute (GRI)/U.S. Environmental Protection Agency. *Research and Development, Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps*. June 1996 (EPA-600/R -96-080m).

7.3 Available Controls and Regulatory Approaches

7.3.1 Available VOC Emission Control Options

Natural gas-driven pneumatic pumps emit VOC emissions as part of their normal operation. Depending on the type of pump and the constraints of the location, companies can utilize a variety of technologies that have been developed over the years. In situations where the replacement of natural gas-driven pumps with electric, solar and instrument air pumps is not feasible, emissions can be captured and routed to a VRU or to a combustion device.

Sections 7.3.1.1 and 7.3.1.2 discuss the control of VOC emissions by replacing natural gas-driven pumps with solar pumps and electric pumps. Section 7.3.1.3 discusses the use of an instrument air system to drive the pneumatic pump in order to eliminate VOC emissions. Lastly, section 7.3.1.4 discusses reducing VOC emissions by routing emissions from the pump to a combustion device, and section 7.3.1.5 discusses capturing VOC emissions using a VRU.

7.3.1.1 *Solar Pumps*

Description

Solar pumps provide the same functionality as natural gas-driven pumps and can be utilized at remote sites where electricity is not available. However, peer review comments received on the EPA's white paper "Oil and Natural Gas Sector Pneumatic Devices" noted that they predominantly operated solar-powered pneumatic pumps for chemical injection and the pumps failed as early as after two to three cloudy days due to insufficient battery charge.¹¹⁸ When solar pumps are properly charged, a solar-charged DC pump can handle a range of throughputs up to 100 gallons per day with maximum injection pressure around 3,000 psig and have no VOC emissions. Converting natural gas-driven chemical pumps can reduce methane emissions by an estimated 3.46 tpy per diaphragm pump and 0.38 tpy per piston pump for all segments of the oil and natural gas industry.¹¹⁹ Based on the gas composition for natural gas in the production segment, we estimate that replacement of a pneumatic pump with a solar-powered pump will reduce VOC emissions by 0.96 tpy per diaphragm pump and 0.11 tpy for a piston pump.

¹¹⁸ Reese, Carrie, Environmental Compliance Manager. Comments on the Oil and Natural Gas Sector Pneumatic Devices. Pioneer Natural Resources.

¹¹⁹ U.S. Environmental Protection Agency. PRO Fact Sheet No. 202. *Convert Natural Gas-Driven Chemical Pumps*.

Control Effectiveness

Replacing a natural gas-driven pump with a solar pump can result in 100 percent reduction in VOC emissions and is feasible in regions where there is sufficient sunlight to power the pump, and backup power is not required. Although, as stated above, solar-powered pumps are capable of pumping up to 100 gallons per day, they are typically used for low volume applications to inject methanol or corrosion inhibitors into a well with typical volumes ranging from 6 to 8 gallons per day. In addition to the low volume pumps, large volume pumps used to replace natural gas-assisted circulation pumps for glycol dehydrators can also be converted to solar.

Cost Impacts

The primary costs associated with conversion to solar pumps are the initial capital expenditures. Solar pumps generally have low maintenance costs, which are typically lower than natural gas-driven pump maintenance costs. The cost being attributed to the replacement of pneumatic pumps with solar-powered pumps includes the capital cost of the pump and its associated operating costs. The operating costs are estimated to be 10 percent of the capital cost. Based on the Natural Gas STAR document, “PRO Fact Sheet: Convert Natural Gas-Driven Chemical Pumps,”¹²⁰ the capital (purchase) cost for a solar-powered electric pump is approximately \$2,000 with solar panels having a lifespan of 15 years and electric motors lasting 5 years. The total capital cost, including installation and labor is \$2,227 (2012 dollars). We estimate there would be no additional annual operating costs for solar pumps above and beyond that of ordinary field personnel duties. Annualized over the life of the pump at a 7 percent discount rate, the annualized cost of replacing a pneumatic pump with a solar pump is \$317. In addition, the use of solar pumps will have savings realized from the natural gas not released. We estimate that each diaphragm pump replaced will save 197 Mcf per year of natural gas from being emitted and each piston pump will have a natural gas savings of 22 Mcf per year. The value of the natural gas saved based on \$4.00 per Mcf would be \$786 per year per diaphragm pump and \$87 per year per piston pump.

¹²⁰ U.S. Environmental Protection Agency. PRO Fact Sheet No. 202. *Convert Natural Gas-Driven Chemical Pumps*.

7.3.1.2 *Electric Pumps*

Description

Electric pumps provide the same functionality as natural gas-driven pumps, and are only restricted by the use of reliable power. Electric pumps have no VOC emissions, and converting a natural gas-driven pneumatic pump to an electric pump can reduce VOC emissions by an estimated 0.96 tpy per diaphragm pump and 0.11 tpy per piston pump.

Control Effectiveness

Replacing a natural gas-driven pump with an electric pump can result in 100 percent reduction in VOC emissions. However, use of electric pumps requires a sufficient and reliable source of electricity. These pumps are, therefore, more common at natural gas processing plants or large dehydration facilities that have access to reliable electric power.

Cost Impacts

The primary costs associated with converting natural gas-driven pumps to electric pumps are the initial capital expenditures, installation and ongoing operation and maintenance. Based on the Natural Gas STAR document, “PRO Fact Sheet: Convert Natural Gas-Driven Chemical Pumps,”¹²¹ the cost of an electric pump to replace a diaphragm pump is \$4,647 and to replace a piston pump is \$1,819 in 2012 dollars depending on the horsepower of the unit.¹²² The annual operating costs for an electric pump are estimated to be \$293. Based on these costs annualized over the life expectancy of the pump at a 7 percent discount rate, the annualized cost for an electric pump to replace a diaphragm pump is \$954, and \$552 to replace a piston pump. In addition, the use of electric pumps will have savings realized from the natural gas not released. We estimate that each diaphragm pump replaced will save 197 Mcf per year of natural gas from being emitted and each piston pump will have a natural gas savings of 22 Mcf per year. The value of the natural gas saved based on \$4.00 per Mcf would be \$786 per year per diaphragm pump and \$87 per year per piston pump.

¹²¹ Ibid.

¹²² U.S. Environmental Protection Agency. *Lessons Learned. Replacing Gas-Assisted Glycol Pumps with Electric Pumps*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. 2006. October 2006.

7.3.1.3 *Instrument Air System*

Description

Instrument air systems require a compressor, power source, dehydrator, and volume tank. The same pneumatic pumps can be used for natural gas and compressed air, without altering any of the parts of the pneumatic pump, but instrument air eliminates the emissions of natural gas. All facilities that have access to an adequate and reliable source of electricity can install an instrument air system. The following, taken from the Natural Gas STAR document, “PRO Fact Sheet: Convert Gas Pneumatic Controls to Instrument Air,”¹²³ describes the major components of an instrument air system:

- (1) Compressors used for instrument air delivery are available in various types and sizes, from rotary screw (centrifugal) compressors to positive displacement (reciprocating piston) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system, and the typical emission rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank. For reliability, a full spare compressor is normally installed.
- (2) A critical component of the instrument air control system is the power source required to operate the compressor. Because high-pressure natural gas is abundant and readily available, natural gas-driven pneumatic systems can run uninterrupted on a 24-hour, 7-day per week schedule. The reliability of an instrument air system, however, depends on the reliability of the compressor and electric power supply. Most large natural gas plants have either an existing electric power supply or have their own power generation system. For smaller facilities and remote locations, however, a reliable source of electric power can be difficult to ensure. In some instances, solar-powered, battery-operated air compressors can be feasible for remote locations, which would both reduce VOC emissions and energy consumption. Small natural gas-powered fuel cells are also being developed.

¹²³ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

- (3) Dehydrators, or air dryers, are an integral part of the instrument air compressor system. Water vapor present in atmospheric air condenses when the air is pressurized and cooled, and can cause a number of problems to these systems, including corrosion of the instrument parts and blockage of instrument air piping and controller orifices.
- (4) The volume tank holds enough air to allow the pneumatic control system to have an uninterrupted supply of high-pressure air without having to run the air compressor continuously. The volume tank allows a large withdrawal of compressed air for a short time, such as for a motor starter, pneumatic pump, or pneumatic tools, without affecting the process control functions.

Control Effectiveness

Instrument air eliminates all emissions from natural gas-driven pneumatic pumps, but can only be utilized in locations with sufficient and reliable electrical power. Furthermore, instrument air systems are more economical and, therefore, more common at facilities with a high concentration of pneumatic devices and where an operator can ensure the system is properly functioning.¹²⁴ Because all emissions can be avoided by converting natural gas-driven chemical pumps to instrument air, methane emissions can be reduced by an estimated 3.46 tpy per diaphragm pump and 0.38 tpy per piston pump. Based on the gas composition for natural gas in the production segment, we estimate that converting a natural gas-driven pneumatic pump to instrument air will reduce VOC emissions by 0.96 tpy per diaphragm pump and 0.11 tpy per piston pump.

Cost Impacts

As stated previously, instrument air conversions require a compressor with a capacity based on the number of control loops at the location. The compressor size is equivalent to the volume of gas used by the control loops after adjusting for gas losses during drying, plus any utility air necessary at the facility. This volume can either be calculated via a meter or utilizing a rule of thumb of one cubic foot per minute (cfm) of instrument air per control loop.¹²⁵

The costs associated with instrument air systems are primarily capital costs for the compressor(s), air dryer and the volume tank, but also include operational costs for electricity to

¹²⁴ Ibid.

¹²⁵ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

drive the compressor motor. Other components of the instrument air system, including piping, control instruments and valve actuators, would already be in place for a gas system. We assume that existing processing plants have an instrument air system in place, including backup systems, and that the cost of increasing air load on the system would be confined to the incremental cost associated with upgrading or replacing the compressor and connecting the pumps to the system. The size of the compressor required would depend on the additional air load required for the instrument air system to handle the pneumatic pumps. Table 7-3 summarizes cost estimates to replace various size compressors in an existing instrument air system.

Table 7-3. Cost of Compressor Replacement for Existing Instrument Air System (\$2012)

Compressor Size	Total Capital Cost ^a	Annualized Cost ^b	Total O&M Cost ^c	Annual Cost ^d
Small	\$5,999	\$854	\$9,197	\$10,051
Medium	\$29,989	\$4,270	\$28,002	\$32,271
Large	\$52,779	\$7,515	\$64,880	\$72,394

^a 2016 NSPS TSD.

^b Annualized capital cost using a 7 percent interest rate and an equipment life of 10 years.

^c The total O&M includes both the annual labor cost and the annual power cost.

^d The total annual cost includes the annualized capital cost and the total O&M cost.

7.3.1.4 Route Emissions to an Existing or New Combustion Device

Description

Typical combustion devices used in the oil and natural gas industry to control VOC emissions and their control efficiency are discussed in greater detail in section 4.3.1.2 of chapter 4 of this document. It is assumed that most processing plants and large dehydration facilities have at least one existing combustion device onsite.

Control Effectiveness

Routing emissions from a natural gas-driven pump to an existing combustion device, or a newly installed combustion device does not reduce the volume of natural gas discharged from the pump, but rather combusts the gas. Based on the gas composition for natural gas in the production segment, we estimated that routing emissions to a combustion device would reduce VOC emissions by an estimated 0.91 tpy per diaphragm pump and 0.1 tpy per piston pump.

Cost Impacts

Routing natural gas to an existing combustion device or installing a new combustion device have associated capital and operating costs. Based on costs for a combustion device provided in the 2015 NSPS TSD, the capital cost for installing a new combustion device to control emissions is estimated to cost \$34,250 and the annual operating cost is \$17,001 in 2012 dollars. Based on the life expectancy for a combustion device, we estimate the annualized cost of installing a new combustion device to be approximately \$21,877, using a 7 percent discount rate. The capital cost for routing emissions to an existing control device to control emissions is estimated to be \$5,433 with an annualized cost of \$774, using a 7 percent discount rate. Because the natural gas captured is combusted there is no gas savings associated with the use of a combustion device to reduce VOC emissions. Table 7-4 presents the estimated VOC cost of control for routing natural gas-driven pump emissions to an existing combustion device. Table 7-5 presents the cost of control for routing natural gas-driven pump emissions to a new combustion device.

Table 7-4. VOC Cost of Control for Routing Natural Gas-Driven Pump Emissions to an Existing Combustion Device

Pump Type/ Segment	VOC Emission Reductions (tpy/pump)	Annualized Cost (\$2012)	VOC Cost of Control (\$2012/ton)
<i>Diaphragm Pumps</i>			
Production	0.91	\$774	\$847
Processing	0.91	\$774	\$847
<i>Piston Pumps</i>			
Production	0.10	\$774	\$7,709
Processing	0.10	\$774	\$7,709

Table 7-5. VOC Cost of Control for Routing Natural Gas-Driven Pump Emissions to a New Combustion Device

Pump Type/ Segment	VOC Emission Reductions (tpy/pump)	Annualized Cost (\$2012)	VOC Cost of Control (\$2012/ton)
<i>Diaphragm Pumps</i>			
Production	0.91	\$21,877	\$23,944
Processing	0.91	\$21,877	\$23,944
<i>Piston Pumps</i>			
Production	0.10	\$21,877	\$218,017
Processing	0.10	\$21,877	\$218,017

7.3.1.5 *Route Emissions to a Vapor Recovery Unit (VRU)*

Description

Vapor recovery units capture low-pressure vapor streams, increase the pressure by means of a compressor, and then route the vapor stream to a process or other useful purpose. These systems typically include a backup compressor system to allow for shutdowns and repairs. Vapor recovery units are more economical for facilities with multiple natural gas emission sources that can be routed to the VRU. Some of these other emission sources can include tanks, dehydrators, and compressors and as a result, VRUs are more common at natural gas processing plants. Vapor recovery units are discussed in greater detail in section 4.3.1.1 of chapter 4 of this document.

Control Effectiveness

Use of a vapor recovery technology has the potential to reduce the VOC emissions from natural gas-driven pumps by 100 percent if all vapor is recovered. We recognize that VRUs may not continuously meet this efficiency in practice. Therefore, we estimate that routing emissions from a natural gas-driven pump to an existing or newly installed VRU can reduce the VOC emitted by approximately 95 percent (accounting for any reduced efficiency that may occur) while, at the same time, capturing the natural gas for beneficial use. We estimate that methane emission reductions for routing gas to a VRU to be 3.29 tpy for a diaphragm pump and 0.36 tpy for a piston pump. Based on the gas composition for natural gas in the production segment, we

estimate that routing emissions to a VRU can reduce VOC emissions by 0.91 tpy per diaphragm pump and 0.1 tpy per piston pump.

Cost Impacts

Based on costs for a VRU provided in the 2015 NSPS TSD, we estimate the capital cost of installing a VRU to be \$104,111 and the annual operation and maintenance cost to be \$9,932 in 2012 dollars. The total annualized cost of a new VRU is estimated to be \$24,755 based on a 7 percent discount rate.

If a VRU is already onsite, then the additional costs for routing emissions from a pump are small, as the majority of costs are piping. We estimated the cost of routing emissions to an existing VRU to be \$5,433 in 2012 dollars. The annualized cost of routing natural gas emissions to an existing VRU is estimated to be \$774 based on a 7 percent discount rate. In addition, there is potential for beneficial use of natural gas recovered through the VRU. We estimated the annual natural gas recovered to be 187 Mcf per year per diaphragm pump and 21 Mcf per year per piston pump. The resulting natural gas savings is estimated to be \$749 per diaphragm pump and \$84 per piston pump, per year based on a value of \$4.00 per Mcf of natural gas recovered. Table 7-6 presents the estimated VOC cost of control for routing natural gas-driven pump emissions to an existing VRU. Table 7-7 presents the estimated VOC cost of control for routing gas-driven pump emissions to a new VRU.

Table 7-6. VOC Cost of Control for Routing Natural Gas-Driven Pump Emissions to an Existing VRU

Pump Type/ Segment	VOC Emission Reductions (tpy/pump)	Annualized Cost (\$2012)	VOC Cost of Control (\$2012/ton)	
			Without savings	With savings
Diaphragm Pumps				
Production	0.91	\$774	\$847	\$27
Processing	0.91	\$774	\$847	\$27
Piston Pumps				
Production	0.10	\$774	\$7,709	\$6,876
Processing	0.10	\$774	\$7,709	\$6,876

Table 7-7. VOC Cost of Control for Routing Natural Gas-Driven Pump Emissions to a New VRU

Pump Type/ Segment	VOC Emission Reductions (tpy/pump)	Annualized Cost (\$2012)	VOC Cost of Control (\$2012/ton)	
			Without savings	With savings
Diaphragm Pumps				
Production	0.91	\$24,755	\$27,094	\$26,275
Processing	0.91	\$24,755	\$27,094	\$26,275
Piston Pumps				
Production	0.10	\$24,755	\$246,697	\$245,864
Processing	0.10	\$24,755	\$246,697	\$245,864

7.3.2 Existing Federal, State and Local Regulations

7.3.2.1 *Federal Regulations that Specifically Require Control of VOC Emissions*

The EPA has finalized federal requirements for natural gas-driven pneumatic pumps under subpart OOOOa. Under subpart OOOOa, each natural gas-driven diaphragm pump located at a natural gas processing plant must have zero natural gas emissions, and each natural gas-driven diaphragm pump located at a well site must capture and route emissions to a control device or process if there is an existing control device or process available onsite. Subpart OOOOa requires that VOC and methane emissions be reduced by 95 percent or greater unless the existing control device or process is not capable of reducing emissions by 95 percent or greater, unless (1) there is no control device onsite, (2) it is technically infeasible, or (3) the control device cannot achieve 95 percent control. Subpart OOOOa also includes an exemption from control requirements where a diaphragm pump operates for any period of time each calendar day for less than a total of 90 days per calendar year.

7.3.2.2 *State and Local Regulations that Specifically Require Control of VOC Emissions*

States may have permitting restrictions on VOC emissions that may apply to an emission source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met and, often, how the source may be operated. To ensure that

sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

At least one state (Wyoming) requires emissions associated with the discharge streams from all natural gas-operated pneumatic pumps be controlled by at least 98 percent or routed into a closed-loop system (e.g., sales line, collection line, fuel supply line). Several states also have registration rules for controlling fugitive VOC emissions (which may include fugitive emissions from pneumatic pumps).

7.4 Recommended RACT Level of Control

We evaluated available data obtained in the development of the 2016 NSPS final rule, comments received on the draft CTG and 2015 NSPS proposed rule, and peer review comments received on the EPA’s white paper “Oil and Natural Gas Sector Pneumatic Devices.” Based on our evaluation of these data and information, we recommend that VOC emissions from pneumatic pumps be controlled.

Our recommended RACT for an existing individual natural gas-driven diaphragm pump located at the well site is to capture and route VOC emissions to a control device or process where there is an existing control device or process available onsite. Our rationale for this recommendation is that, although the production segment includes both well sites and gathering and boosting stations, we currently only have reliable information for pumps located at well sites. We have determined that the cost of control for routing VOC emissions to an existing onsite control device or process would be reasonable. As presented in Tables 7-4 and 7-6 in sections 7.3.1.4 and 7.3.1.5 of this chapter, the VOC cost of control when an existing combustion device or VRU is available onsite was estimated to be \$847 per ton of VOC reduced for diaphragm pumps, without gas savings, and \$27 per ton of VOC reduced for diaphragm pumps if a VRU is used and gas savings are considered. We do not consider requiring control where there is not an existing control device or process onsite to be reasonably available technology, and the cost per ton of VOC reduced was estimated at greater than \$20,000 for diaphragm pumps. While we are not recommending that the owner or operator be required to install a control device to control pneumatic pump emissions if one is not already available, we note that control devices will likely be installed onsite for other purposes under RACT or other regulations and will be available to control emissions from pneumatic pumps to a 95 percent control level.

For purposes of our recommended RACT, a natural gas-driven diaphragm pump is a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump for purposes of our recommended RACT. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

We do not recommend RACT apply to an existing individual natural gas-driven piston pump because currently available information (including information received on the draft CTG and 2015 NSPS proposal) indicates that piston pumps are low emitting because of their small size, design and usage patterns. We determined piston pumps have emission rates between 2.2 to 2.5 scf/hr based on a joint report from the EPA and the Gas Research Institute on methane emissions from the natural gas industry. This approach is consistent with the manner in which we addressed low-bleed pneumatic controllers. After considering the low emission rates of low-bleed pneumatic controllers, we do not recommend RACT apply to these sources. Similarly, based upon the information that we have on the low emission rates of piston pumps, we are not recommending RACT apply to these sources because VOC emissions are low and would not be reasonable to control in the same manner that we recommend for diaphragm pumps. As presented in Tables 7-4 and 7-6 in sections 7.3.1.4 and 7.3.1.5 of this chapter, the VOC cost of control when an existing combustion device or VRU is available onsite was estimated to be \$7,709 per ton of VOC reduced for piston pumps, without gas savings, and \$6,876 per ton of VOC reduced for piston pumps if a VRU is used and gas savings are considered. Requiring control where there is not an existing control device or process onsite was estimated to cost more than \$200,000 per ton of VOC reduced for piston pumps.

For existing natural gas-driven diaphragm pumps at well sites, we recommend that air agencies require VOC emissions be controlled by 95 percent. Our rationale for recommending this level of emission reduction is supported by the control level achievable on a continuing basis by control devices and processes already located onsite or later installed onsite to control other emissions under RACT or other regulations. We expect that newly-installed control devices will achieve emission reductions because owners or operators are installing them to meet control requirements for other sources. In the unlikely circumstance where a control device that can achieve a 95 percent reduction is not available onsite, we recommend that owners and operators

still be required to control VOC emissions to the level achievable by the control device. We recommend that owners and operators in those instances be required to maintain documentation of the percent control the onsite control device is designed to achieve. We make this additional recommendation because it will achieve emission reductions with regard to pneumatic pumps even in the unlikely circumstance that the only available control device cannot achieve a 95 percent reduction.

We also recommend that air agencies allow for an exemption based on technical infeasibility. We recommend a technical infeasibility exemption be allowed based on information we received from industry that indicates that there may be circumstances where there is insufficient gas pressure or control device capacity, making it technically infeasible to capture and route pneumatic pump emissions to a control device or process.

We recommend that, at well sites, if a diaphragm pump operates for any period of time each calendar day for less than a total of 90 days per calendar year, the pump not be subject to the recommended control requirements. We make this recommendation to account for those intermittently used pumps/portable pumps where VOC emissions would be lower than assumed in our analysis (i.e., our analysis assumes that diaphragm pumps are operated 40 percent of the time evenly throughout the year) and not reasonable to control.

Our recommended RACT for existing diaphragm pumps located at natural gas processing plants is that they have zero VOC emissions (or 100 percent control) (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring an emission rate greater than zero). Our rationale for selecting a VOC emission rate of zero (with functional and safety exceptions) for our recommended RACT is based on the ability of most natural gas processing plants to install and utilize an instrument air system. As discussed in section 7.3.1.3 of this chapter, by using an instrument air system, compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic system. Therefore, the use of instrument air eliminates VOC emissions from each gas-driven diaphragm pump and supports a VOC emission rate of zero.

In summary, we recommend the following RACT for pneumatic pumps in the oil and natural gas industry:

- (1) Each Diaphragm Pump Located at a Natural Gas Processing Plant: Require zero VOC emissions (or 100 percent control). This can be achieved by use of an instrument air system in place of natural gas-driven pump.
- (2) Each Diaphragm Pump Located at a Well Site: Require that VOC emissions be captured and routed to an existing control device or process that is located onsite, unless it is technically infeasible to route emissions to the existing control device or process. Require 95 percent control of VOC emissions, unless the existing control device or process cannot achieve 95 percent control. If the existing control device cannot achieve a 95 percent control, still require the emissions to be routed to the existing onsite control device to control emissions to the extent achievable and maintain documentation of the percent control the onsite control device is designed to achieve. If there is no existing control device at the location of the pump, submit a certification that there is no device. If a control device is subsequently added to the site where the pump is located, then the VOC emissions from the pump must be captured and routed to the newly installed control device.

Although sources have a choice on how they meet the RACT level of control, the technologies that will likely be used to meet the RACT level of control for each natural gas-driven diaphragm pump at a well site are either capturing and routing the VOC emissions to an onsite existing combustion device (or a subsequently installed combustion device) or capturing and routing the VOC emissions to a process using an onsite existing VRU (or a subsequently installed VRU).

Similarly, the technology that will likely be used to meet the RACT level of control for each diaphragm pump located at a natural gas processing plant is the use of an existing instrument air system assumed to already exist onsite at natural gas processing plants.

7.5 Factors to Consider in Developing Pneumatic Pump Compliance Procedures

7.5.1 Oil and Natural Gas Production Segment Recommendations

We recommend that air agencies require owners and operators of diaphragm pumps located at well sites that meet RACT by capturing emissions and routing to a control device be connected through a closed vent system and that the closed vent system be designed with no

detectable emissions (using a 500 ppm detection level, as measured using Method 21 of appendix A-7 of part 60, and ongoing monthly, olfactory and auditory inspections). We recommend that you require that owners and operators conduct an assessment and certify that the closed vent system is of sufficient design and capacity to ensure that emissions are routed to the control device. We recommend air agencies require that any detected defects be repaired as soon as practicable.

With the exception of low leg drains, high point bleeds, analyzer vent, open-ended valves and safety devices, if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process, air agencies should require that owners or operators either:

- (1) Install, calibrate, maintain and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings and either sounds an alarm or initiates notification via remote alarm to the nearest field office when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere; or
- (2) Secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

Secondly, we recommend that air agencies require owners and operators of diaphragm pumps at well sites provide certifications for when (1) there is no existing control device or process onsite, or (2) capturing and routing to an existing control device or process is not technically feasible.

Lastly, we recommend that air agencies require owners and operators of diaphragm pumps at well sites maintain records documenting where (1) intermittently-used/portable diaphragm pumps operate for any period of time each calendar day for less than a total of 90 calendar days per year, (2) an onsite control device or process is designed to achieve less than 95 percent reduction, and (3) a diaphragm pump is routed to a control device or a process and the control device or process is subsequently removed.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

7.5.2 Natural Gas Processing Segment Recommendations

We recommend that air agencies require owners and operators of diaphragm pumps located at natural gas processing plants maintain records documenting (1) the location and manufacturer's specifications of each pneumatic pump, (2) that the natural gas bleed rate is zero, and (3) deviations in cases where a pneumatic pump was not operated in compliance with RACT. We also recommend that air agencies require owners and operators submit annual reports that include records of deviations that occurred during the reporting period.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

8.0 EQUIPMENT LEAKS FROM NATURAL GAS PROCESSING PLANTS

This chapter presents the causes for equipment leaks from natural gas processing plants, and provides emission estimates for “model” facilities in the processing segment of the oil and natural gas industry. Methods that are designed to reduce equipment leak emissions are presented, along with our recommended RACT, and the associated VOC emission reductions and cost impacts for equipment leaks from natural gas processing plants.

This CTG and the recommended RACT included in this CTG replaces the following: *Guideline Series. Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants*. December 1983. EPA-450/3-83-007.

8.1 Applicability

For purposes of this CTG, the emissions and emission controls discussed herein would apply to the group of all equipment (except compressors and sampling connection systems) within a process unit located at a natural gas processing plant in VOC service or in wet gas service, and any device or system that is used to control VOC emissions (e.g., a closed vent system). For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, the piece of equipment must contain or contact the field gas before the extraction step at a natural gas processing plant. Equipment is defined as each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service.

8.2 Process Description and Emission Sources

8.2.1 Process Description

Natural gas processing involves the removal of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. The types of process equipment used to separate the liquids are separators, glycol dehydrators, and amine treaters. In

addition, centrifugal and/or reciprocating compressors are used to pressurize and move the natural gas from the processing facility to the transmission stations.

There are several potential sources of equipment leak emissions at natural gas processing plants. Equipment such as pumps, pressure relief devices, valves, flanges, and other connectors are potential sources that can leak due to seal failure. Other sources, such as open-ended lines and valves may leak for reasons other than faulty seals, such as an improperly installed cap on an open-ended line. In addition, corrosion of welded connections, flanges, and valves may also be a cause of equipment leak emissions. The following subsections describe potential equipment leak sources and the magnitude of the VOC emissions from natural gas processing plants.

Due to the large number of valves, pumps, and other equipment within natural gas processing plants, VOC emissions from leaking equipment can be significant (chapter 2.2 of the 1983 CTG¹²⁶ presents a description of these equipment components and is not repeated here).

8.2.2 Equipment Leak Emission Data and Emission Factors

8.2.2.1 Summary of Major Studies and Emission Factors

The 2012 NSPS TSD evaluated emissions data from equipment leaks collected from chemical manufacturing and petroleum production to assist in the development of control strategies for reducing VOC emissions from these sources.^{127,128,129} Table 8-1 presents a list of the studies consulted along with an indication of the type of information contained in the study. In addition to these sources, we evaluated the peer reviewer and public comments received on the EPA's white paper, "Oil and Natural Gas Sector Leaks."¹³⁰

¹²⁶ U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC, 27711. *Guideline Series. Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants*. December 1983. EPA-450/3-83-007.

¹²⁷ Memorandum from David Randall, RTI and Karen Schaffner, RTI to Randy McDonald, U.S. Environmental Protection Agency. *Control Options and Impacts for Equipment Leaks: Chemical Manufacturing Area Source Standards*. September 2, 2008.

¹²⁸ Memorandum from Kristen Parrish, RTI and David Randall, RTI to Karen Rackley, U.S. Environmental Protection Agency. *Final Impacts for Regulatory Options for Equipment Leaks of VOC on SOGMI*. October 30, 2007.

¹²⁹ Memorandum from Kristen Parrish, RTI, David Randall, RTI, and Jeff Coburn, RTI to Karen Rackley, U.S. Environmental Protection Agency. *Final Impacts for Regulatory Options for Equipment Leaks of VOC in Petroleum Refineries*. October 30, 2007.

¹³⁰ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Leaks. Report for Oil and Natural Gas Sector Leaks Review Panel*. Office of Air Quality Planning and Standards (OAQPS). April 2014.

Table 8-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options^r
Protocol for Equipment Leak Emission Estimates ^a	EPA	1995	None	X	X
Methane Emissions from the Natural Gas Industry: Equipment Leaks ^b	EPA/GRI	1996	Nationwide	X	X
Greenhouse Gas Reporting Program ^c	EPA	2014	Nationwide	X	X
Inventory of Greenhouse Gas Emissions and Sinks ^d	EPA	Annual	Nationwide	X	
Methane Emissions from the Natural Gas Industry ^{e,f,g,h}	EPA/GRI	1996	Nationwide	X	X
Methane Emissions from the U.S. Petroleum Industry ⁱ	EPA	1996	Nationwide	X	
Methane Emissions from the U.S. Petroleum Industry ^j	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States ^k	Western Regional Air Partnership	2005	Regional	X	X
Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories ^l	Central States Regional Air Partnership	2008	Regional	X	X
Oil and Gas Producing Industry in Your State ^m	Independent Petroleum Association of America	2009	Nationwide		
Emissions from Natural Gas Production in the Barnett Shale and Opportunities for Cost-effective Improvements ⁿ	Environmental Defense Fund	2009	Regional	X	X
Emissions from oil and Natural Gas Production Facilities ^o	Texas Commission for Environmental Quality	2007	Regional	X	X
Petroleum and Natural Gas Statistical Data ^p	U.S. Energy Information Administration	2007-2009	Nationwide		

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options ^r
Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations ^q	EPA	1999		X	X

^a U.S. Environmental Protection Agency, *Protocol for Equipment Leak Emission Estimates*. Office of Air Quality Planning and Standards. Research Triangle Park, NC. November 1995. EPA-453/R-95-017. Available at <http://www.epa.gov/ttn/chief/efdocs/equiplks.pdf>.

^b Gas Research Institute (GRI)/U.S. Environmental Protection Agency. *Research and Development, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*. June 1996 (EPA-600/R-96-080h).

^c U.S. Environmental Protection Agency. Greenhouse Gas Reporting Program. (Annual Reporting; Current Data Available for 2011-2013). 2014.

^d U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. <https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html>.

^e U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 2: Technical Report*. EPA-600/R-96-080b. June 1996.

^f U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 3: General Methodology*. EPA-600/R-96-080c. June 1996.

^g U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 5: Activity Factors*. EPA-600/R-96-080e. June 1996.

^h U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 6: Vented and Combustion Source Summary Emissions*. EPA-600/R-96-080f. June 1996.

ⁱ U.S. Environmental Protection Agency/GRI. *Methane Emissions from the U.S. Petroleum Industry, Draft Report*. June 14, 1996.

^j ICF Consulting. *Estimates of Methane Emissions from the U.S. Oil Industry*. Prepared for the U.S. Environmental Protection Agency. 1999.

^k ENVIRON International Corporation. *Oil and Gas Emission Inventories for the Western States*. Prepared for Western Governors' Association. December 27, 2005.

^l ENVIRON International Corporation. *Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories Prepared for Central States Regional Air Partnership*. November 2008.

^m Independent Petroleum Association of America. *Oil and Gas Producing Industry in Your State*.

ⁿ Armendariz, Al. *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements*. Prepared for Environmental Defense Fund. January 2009.

^o Eastern Research Group, Inc. *Emissions from Oil and Gas Production Facilities*. Prepared for the Texas Commission on Environmental Quality. August 31, 2007.

^p U.S. Energy Information Administration. *Annual U.S. Natural Gas Wellhead Price*. U.S. Energy Information Administration. Natural Gas Navigator. Retrieved online on 12 Dec 2010 at <http://www.eia.doe.gov/dnav/ng/hist/n9190us3a.htm>.

^q Eastern Research Group, Inc. *Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operation*. Prepared for the U.S. Environmental Protection Agency. September 1999.

^r An "X" in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

8.2.2.2 *Natural Gas Processing Model Plant*

Natural gas processing plants can consist of a variety of combinations of process equipment and components. In order to conduct analyses to be used in evaluating potential options to reduce emissions from leaking equipment, the 2011 NSPS TSD and the 2012 NSPS TSD used a model plant approach.

Information related to equipment counts were obtained from a natural gas industry report.¹³¹ This document provided average equipment counts for gas production and gas processing segments. These average counts were used to develop a model plant. These equipment counts are consistent with those contained in the EPA's analysis to estimate methane emissions conducted in support of the GHGRP. The natural gas processing model plant is discussed in the following section. A summary of the model plant production equipment counts for a gas processing facility is provided in Table 8-2.

Table 8-2. Equipment Counts for Natural Gas Processing Model Plant

Equipment	Equipment Count (non-compressor equipment)
Valves	1,392
Connectors	4,392
Open-Ended Lines (OEL)	134
Pressure Relief Valve (PRV)	29

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-13, June 1996. (EPA-600/R-96-080h)

8.2.2.3 *Natural Gas Processing Model Plant Emissions*

Overview of Approach

The EPA gathered equipment leak data and cost information for the development of the proposed National Uniform Emission Standards for Equipment Leaks rule (58 FR 17898, March 26, 2012). These Uniform Standards data were used to estimate baseline emissions for a natural

¹³¹ U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*. Table 4-13, June 1996. (EPA-600/R-96-080h).

gas processing model plant for the 2012 NSPS STSD and provide the baseline and controlled emission options for processing plants presented in this CTG.^{132,133}

The baseline emissions were defined as being equivalent to a 40 CFR part 60, subpart VV (subpart VV) leak detection and repair (LDAR) program, which represents the same set of requirements that apply to natural gas processing plants under 40 CFR part 60, subpart KKK (subpart KKK). The 2012 NSPS requires the implementation of 40 CFR part 60, subpart VVa (subpart VVa) and currently applies to natural gas processing plants constructed or modified after August 23, 2011. It is assumed that natural gas processing plants constructed, reconstructed or modified on or before August 23, 2011 currently still comply with subpart KKK, which is similar to the control level of subpart VV. We evaluated requiring a similar subpart VVa level of control to these plants as was required under the 2012 NSPS. We used leak frequency data (refers to the estimated percentage of equipment that will be found leaking at a given leak definition) to calculate emission estimates, in addition to several other sources of information (including the Protocol for Equipment Leak Emissions Estimates and industry data).¹³⁴ Table 8-3 provides a summary of the equipment leak frequency data used for the natural gas processing model plant. Emission factors are the estimated leak rates for an equipment type at a given leak definition and are normally given in kg/hr/piece of equipment. Table 8-4 provides a summary of the VOC equipment leak emission factors representing the subpart VVa level of control that was used for the natural gas processing model plant.

¹³² Memorandum from Cindy Hancy, RTI International to Jodi Howard, EPA/OAQPS. *Analysis of Emission Reduction Techniques for Equipment Leaks*. December 21, 2011.

¹³³ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.

¹³⁴ U.S. Environmental Protection Agency. *Protocol for Equipment Leak Emission Estimates*. November 1995. EPA-453/R-95-017.

Table 8-3. Summary of Equipment Leak Frequency for Natural Gas

LDAR Program ^a	Valves	Connectors
Baseline	1.18/1.18	NA
Valves	5.95/1.91	NA
Connectors	NA	1.70/0.81

NA = Not Applicable; no equipment leak frequency percent data were available.

Data Source: Memorandum from Cindy Hancy, RTI International to Jodi Howard, EPA/OAQPS, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011, Table 5.

^a The leak frequencies provided in the tables are presented as initial leak frequency and subsequent leak frequency under the subpart VVa level of control.

Table 8-4. Summary of VOC Equipment Leak Emission Factors for the Natural Gas Processing Model Plant

Component	Uncontrolled (kg/comp-hr)	Baseline (kg/comp-hr) ^a	Subpart VVa Control Level (kg/comp-hr) ^b
Valves	3.71E-04	2.24E-04	8.85E-05
Connectors	1.04E-04	1.04E-04	3.95E-05
OEL	2.30E-03	7.34E-05	NA
PRV	1.60E-01	9.80E-02	NA

NA = Not Applicable

Data Source: Memorandum from Cindy Hancy, RTI International to Jodi Howard, EPA/OAQPS, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011, Table 7.

^a The baseline option is assumed to be equivalent to a subpart VV LDAR program.

^b Assumed to be equivalent to a subpart VVa LDAR program.

8.3 Available Controls and Regulatory Approaches

8.3.1 Available VOC Emission Control Options

The EPA has determined that leaking equipment, such as valves, pumps, and connectors are a significant source of VOC emissions from natural gas processing plants. The following subsections describe the techniques used to reduce emissions from these sources.

8.3.1.1 Leak Detection and Repair Program

The most commonly employed control technique for equipment leaks is the implementation of an LDAR program. Emission reductions from implementing an LDAR program can potentially reduce product losses, increase safety for workers and operators,

decrease exposure of hazardous chemicals to the surrounding community, and reduce emissions fees. An effective LDAR program will target leaking equipment by establishing leak definitions and require work practices to mitigate the leaks, such as monitoring frequencies for specific types of equipment (i.e., valves, pumps, and connectors). Other elements of an effective LDAR program include:

- (1) Identifying Equipment,
- (2) Monitoring Equipment,
- (3) Repairing Equipment,
- (4) Recordkeeping, and
- (5) Reporting.

The primary sources of equipment leak emissions from natural gas processing plants are valves and connectors because these are the most prevalent equipment and can number in the thousands (see Table 8-2). The major cause of emissions from valves and connectors is a seal or gasket failure due to normal wear or improper maintenance. A leak is detected whenever the measured concentration exceeds the threshold standard (i.e., leak definition) for the applicable regulation. Leak definitions vary by regulation, equipment type, and service (e.g., light liquid, heavy liquid, gas/vapor). Most NSPS regulations that were promulgated prior to 2007 have a valve leak definition of 10,000 ppm, while many National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations use a 500 ppm leak definition for valves or 1,000-ppm leak definition for other equipment such as pumps. In addition, some regulations define a leak based on visual inspections and observations (such as fluids dripping, spraying, misting, or clouding from or around equipment), sound (such as hissing), and smell.

For many NSPS and NESHAP regulations with leak detection provisions, the primary method for monitoring to detect leaking equipment is EPA Reference Method 21 (40 CFR part 60, appendix A-7). Method 21 is a procedure used to detect VOC leaks from equipment using a toxic vapor analyzer (TVA) or organic vapor analyzer (OVA).

A second method for monitoring to detect leaking components is optical gas imaging (OGI) using an infrared (IR) camera. The IR camera may be passive or active. The operator uses the passive IR cameras to scan an area to produce images of equipment leaks from a number of sources. Active IR cameras point or aim an IR beam at a potential source to indicate the presence of gaseous emissions (equipment leaks). An equipment leak is any emissions that are visualized

by an OGI instrument. The optical imaging camera can be very efficient in monitoring multiple pieces of equipment in a short amount of time. However, the optical imaging camera cannot quantify the amount or concentration of the equipment leak.

Acoustic leak detectors measure the decibel readings of high frequency vibrations from the noise of leaking fluids from equipment leaks using a stethoscope-type device. The decibel reading, along with the type of fluid, density, system pressure, and component type can be correlated into leak rate by using algorithms developed by the instrument manufacturer. The acoustic detector does not decrease the monitoring time because components are monitored separately, like the OVA or TVA monitoring. The accuracy of the measurements using the acoustic detector can also be questioned due to the number of variables used to determine the equipment leak emissions.

In addition, other monitoring tools, such as soap solution and electronic screening devices, can be used to find equipment leaks from certain types of equipment. Other factors that can improve the efficiency of an LDAR program include training programs for equipment monitoring personnel and tracking systems that address the cost efficiency of alternative equipment (e.g., competing brands of valves in a specific application).

Subpart VVa LDAR Program

One LDAR option to control VOC emissions from natural gas processing plant equipment leaks is the implementation of the subpart VVa LDAR program. This program is similar to the subpart VV monitoring program (requirements are cross-referenced in subpart KKK), but finds more leaks due to the lower leak definition, increased monitoring frequency, and the addition of connectors to the components being monitored, thereby achieving better emission reductions.

Description

The subpart VVa LDAR program requires the monitoring of pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines, valves, and connectors. These components are monitored with an OVA or TVA to determine if a component is leaking and measures the concentration of the organics if the component is leaking. Connectors and valves have a leak definition of 500 ppm. Valves are monitored monthly, connectors are monitored annually, and open-ended lines and pressure relief valves must be monitored within five days after a pressure release event to ensure they are operating without any detectable

emissions (e.g. at a concentration less than 500 ppm above background). Compressors are not included in this leak detection and repair option and are regulated separately.

Control Effectiveness

The control effectiveness of an LDAR program is based on the frequency of monitoring, leak definition, frequency of leaks, percentage of leaks that are repaired, and the percentage of reoccurring leaks. The control effectiveness of a leak program can vary from 45 to 96 percent and is dependent on the frequency of monitoring and the leak definition.¹³⁵ Descriptions of the frequency of monitoring and leak definition are described further below.

Monitoring Frequency. The monitoring frequency is the number of times each piece of equipment is checked for leaks over a given period of time. With more frequent monitoring, leaks are found and repaired sooner, thus providing higher control effectiveness.

Leak Definition. The leak definition describes the local VOC concentration at the surface of an equipment source where indications of VOC emissions are present. The leak definition is an instrument meter reading, in parts per million based on a reference compound. Decreasing the leak definition generally increases the number of leaks found during a monitoring period, which generally increases the number of leaks that are repaired.

The 2012 NSPS STSD calculated incremental emission reductions from the baseline requirements (assuming that an LDAR program equivalent to the subpart VV/subpart KKK LDAR program is currently implemented at natural gas processing plants), and the leak frequency and emission factors from a supporting document for the Equipment Leak Uniform Standards were used to calculate the emission reductions and costs. The natural gas processing plant component counts (see Table 8-2) were obtained from an EPA/GRI document.¹³⁶ The incremental VOC emission reductions for implementing a subpart VVa leak detection and repair program (as determined in the 2012 NSPS STSD) for the natural gas processing model plant was calculated to be 13 percent.

¹³⁵ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.

¹³⁶ GRI/EPA Research and Development. *Methane Emissions from the Natural Gas Industry; Volume 8: Equipment Leaks*. June 1996. EPA-600/R-96-080h.

Cost Impacts

Table 8-5 presents a summary of the incremental capital and annual costs and the cost of control (estimated in the 2012 NSPS STSD) from baseline (subpart VV) to implementing subpart VVa for the gas processing model plant. The costs obtained from the 2012 NSPS TSD have been converted to 2012 dollars from 2008 dollars using the Federal Reserve Economic Data GDP Price Deflator (Change in GDP: Implicit Price Deflator from 2008 to 2012 (5.69 percent)).¹³⁷

Table 8-5. Summary of the Gas Processing Model Plant VOC Cost of Control for the Subpart VVa Option

Annual VOC Emission Reductions (tpy)	Capital Cost (\$2012)	Annual Cost (\$2012/year)	VOC Cost of Control (\$2012/ton)	
			Without savings	With savings ^a
4.56	\$8,499	\$12,959	\$2,844	\$2,010

^a With savings calculated assuming the natural gas (82.9 percent methane) from the methane reduction has a value of \$4/Mscf. The VOC/methane ratio was assumed to be 0.278.

Table 8-6 provides a summary of the capital and annual costs and the cost of control on a component basis for the natural gas processing model plant.

Table 8-6. Summary of the Gas Processing Component VOC Cost of Control for the Subpart VVa Option

Component	Annual VOC Emission Reductions (tpy)	Capital Cost (\$2012)	Annual Cost (\$2012/year)	VOC Cost of Control (\$2012/ton)	
				Without Savings	With Savings ^a
Valves	1.82	\$5,231	\$9,280	\$5,095	\$4,261
Connectors	2.74	\$8,374	\$4,405	\$1,610	\$776

^a With savings calculated assuming the natural gas (82.9 percent methane) from the methane reduction has a value of \$4/Mscf. The VOC/methane ratio was assumed to be 0.278.

8.3.1.2 Leak Detection and Repair Program with Optical Gas Imaging

Another option to control VOC emissions is the implementation of a program that uses OGI to detect equipment leaks. The alternative work practice for equipment leaks in §60.18(g) of

¹³⁷ U.S. Bureau of Economic Analysis, Gross Domestic Product: Implicit Price Deflator (GDPDEF), retrieved from FRED, Federal Reserve Bank of St. Louis <https://research.stlouisfed.org/fred2/series/GDPDEF>. March, 26, 2015.

40 CFR part 60, subpart A allows the use of an OGI instrument to monitor equipment for leaks. This option is currently available for monitoring equipment leaks from valves, pumps, connectors and other equipment that is subject to monitoring in subpart VVa.

The alternative work practice requires periodic monitoring, based on the detection sensitivity level (grams per hour), of the affected equipment using OGI and an annual monitoring survey of the affected equipment using a Method 21. Method 21 monitoring allows the facility to determine the concentration of a leak and to then use emission factors found in the EPA's emissions leak protocol to quantify emissions from equipment leaks, because the OGI system can only provide the presence of the equipment leaks.

Modeling results, conducted in support of the alternative work practice standard, showed a work practice repeated bimonthly with a detection limit of 60 g/hr range was equivalent to existing Method 21 work practices. The model generated different detection limits for the 500 and 10,000 ppm thresholds in existing rules. Based on modeling, the alternative work practice standard reflects the mass detection limit for 500 ppm, thus, providing equivalency for both 500 and 10,000 ppm thresholds.¹³⁸ The alternative work practice option is assumed to have the same control effectiveness as the subpart VVa monitoring program.

8.3.2 Existing Federal, State and Local Regulations

8.3.2.1 *Federal Regulations that Specifically Require Control of VOC Emissions*

Federal regulations that regulate VOC emissions from equipment leaks at natural gas processing plants include 40 CFR part 60 subpart OOOOa, subpart OOOO, and subpart KKK; and the 1983 CTG document (established a recommended RACT for VOC for natural gas processing plants at a level of control equivalent to subpart KKK).

8.3.2.2 *State and Local Regulations that Specifically Require Control of VOC Emissions*

States may have permitting restrictions on VOC emissions that may apply to an emissions source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed,

¹³⁸ 73 FR 78199, December 22, 2008.

what emission limits must be met, and often how the source must be operated. To ensure that sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

We assume that all states currently regulate equipment leaks at existing natural gas processing plants at the 1983 CTG document and subpart VV level of control.

8.4 Recommended RACT Level of Control for Equipment Leaks from Equipment at Natural Gas Processing Plants

As discussed in section 8.3.2 of this chapter, existing federal, state and local regulations already require the reduction of VOC emissions using an LDAR program. The 2012 NSPS requires a 40 CFR part 60 subpart VVa LDAR monitoring program for processing plants. The 2012 NSPS reported a cost of control for natural gas processing plants to be \$2,844 per ton of VOC removed for the 40 CFR part 60 subpart VVa option.

Based on costs and existing LDAR programs that are already employed at natural gas processing plants, we recommend that RACT for natural gas processing plants be the implementation of an LDAR program equivalent to what is required under 40 CFR part 60 subpart VVa for equipment (with the exception of compressors and sampling connection systems) in VOC service. This RACT recommendation would increase the stringency from the currently implemented LDAR programs at most existing natural gas processing plants (that were built prior to 2012) in VOC service by lowering the leak definitions, increasing the monitoring frequency, and including additional equipment. The subpart VVa leak detection and repair program requires the annual monitoring of connectors using an OVA or TVA (500 ppm leak definition), monthly monitoring of valves (500 ppm leak definition) and requires open-ended lines and pressure relief devices to operate with no detectable emissions (less than 500 ppm above background). The estimated annual incremental VOC emission reductions for the recommended RACT for a natural gas processing plant was estimated to be 4.56 tpy (see Table 8-5 of this chapter). The annual VOC emission reductions assume a baseline level of control equivalent to the 40 CFR part 60, subpart VV LDAR program. Table 8-5 presents the gas processing model plant VOC cost of control for the recommended RACT. The costs assume a baseline level of control equivalent to the 40 CFR part 60, subpart VV LDAR program. The

recommended RACT VOC cost of control is estimated to be \$2,844 per ton of VOC reduced without savings and \$2,010 with savings.

In summary, we recommend the following RACT for equipment leaks at natural gas processing plants:

RACT for Equipment Leaks at Natural Gas Processing Plants: We recommend the implementation of an LDAR program equivalent to what is required under 40 CFR part 60 subpart VVa for equipment (with the exception of compressors and sampling connection systems) in VOC service.

8.5 Factors to Consider in Developing Equipment Leak Compliance Procedures

Existing natural gas processing plants that would be subject to the recommended RACT are already subject to an LDAR program and the basic elements of the LDAR program for the facility are in place. However, the LDAR program would need to be modified to increase the stringency from the currently implemented LDAR program by requiring annual monitoring of connectors using an OVA or TVA (500 ppm leak definition), and lowering the leak definition for valves (500 ppm). As with the currently implemented LDAR program, to ensure that equipment in VOC service that leak at natural gas processing plants are properly monitored and repaired under the LDAR RACT recommendations, we suggest that air agencies specify monitoring frequency, equipment repair, and recordkeeping and reporting requirements to document compliance.

Monitoring frequencies vary according to the applicable regulation, but are typically weekly, monthly, quarterly and yearly. The monitoring frequency depends on the equipment type and periodic leak rate for the equipment. For each piece of equipment that is found to be leaking, the first attempt at repair should be made within a reasonable period of time, such as no later than five calendar days after each leak is detected. First attempts at repair include, but are not limited to, the following best practices, where practicable and appropriate:

- (1) Tightening of bonnet bolts,
- (2) Replacement of bonnet bolts,
- (3) Tightening of packing gland nuts, and
- (4) Injection of lubricant into lubricated packing.

Once the equipment is repaired, it should be re-monitored over the next several days to ensure the leak has been successfully repaired. Another method that can be used to repair equipment is to replace the leaking equipment with a “leakless” equipment or other technologies.

When implementing an LDAR program, we recommend that air agencies consider including recordkeeping requirements that require owner/operators of subject facilities to maintain a list of identification numbers for all equipment subject to an equipment leak regulation. A list of equipment that is designated as “unsafe to monitor” should also be maintained with an explanation/review of conditions for the designation. Detailed schematics, equipment design specifications (including dates and descriptions of any changes), and piping and instrumentation diagrams should also be maintained with the results of performance testing and leak detection monitoring.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

9.0 FUGITIVE EMISSIONS FROM WELL SITES AND GATHERING AND BOOSTING STATIONS

Fugitive emissions from components in the oil and natural gas industry are a source of VOC emissions. This chapter discusses the sources of fugitive emissions, and provides VOC emission estimates for well sites and gathering and boosting stations in the production segment (located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or point of custody transfer to an oil pipeline). This chapter also presents a description of programs that are designed to reduce fugitive emissions, along with costs, and emission reductions. Finally, this chapter provides a discussion of our recommended RACT and the estimated VOC emission reductions and costs for fugitive emissions from well sites and gathering and boosting stations in the production segment.

9.1 Applicability

For purposes of this CTG, the emissions and programs to control emissions discussed herein would apply to the collection of fugitive emissions components at well sites with an average production of greater than 15 barrel equivalents per well per day (15 barrel equivalents)¹³⁹ and the collection of fugitive emissions components at gathering and boosting stations in the production segment.

For the purposes of this CTG, fugitive emission reduction recommendations would not apply to well sites that only contain wellheads.

Fugitive emissions, for the purposes of applicability of this CTG, means those emissions from a stationary source that could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening. Equipment leak emissions at natural gas processing plants are covered under chapter 8 of this document.

¹³⁹ Natural gas production converted to barrel equivalents uses the conversion of 0.178 barrels of crude oil to 1000 cubic feet of natural gas. Based upon conversion factor used for the no longer in service U.S. EIA Financial Reporting System for Major Energy Producers.

9.2 Fugitive Emissions Description and Data

9.2.1 Fugitive Emissions Description

There are several potential sources of fugitive emissions throughout the oil and natural gas industry. Fugitive emissions occur when connection points are not fitted properly or when seals and gaskets start to deteriorate. Changes in pressure, temperature, or mechanical stresses can also cause components or equipment to emit fugitive emissions. Poor maintenance or operating practices, such as improperly reseated PRVs or thief hatches on controlled storage vessels that are left open after sampling, are also potential sources of fugitive emissions. Potential sources of fugitive emissions include agitator seals, connectors, pump diaphragms, flanges, instruments, meters, open-ended lines (OELs), pressure relief devices such as PRVs, pump seals, valves, or improperly controlled liquid storage tanks. These fugitive emissions do not include devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pneumatic pumps, insofar as the natural gas and associated VOC emissions discharged from the device's vent is not considered a fugitive emission.

For the purposes of our RACT analysis for fugitive emissions from components and equipment, we differentiated between the definition of "equipment" for purposes of controlling equipment leaks for oil and natural gas processing plants in subpart OOOO¹⁴⁰ and the definition we use for the purposes of addressing fugitive emissions from oil and natural gas well sites and gathering and boosting stations. For purposes of our RACT analysis, "fugitive emissions component(s)" are the focus of our analysis for fugitive emissions from oil and natural gas well sites and gathering and boosting stations. The definition for "fugitive emissions component" is as follows:

Fugitive emissions component means any component that has the potential to emit fugitive emissions of VOC at a well site or gathering and boosting station, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not already subject to equipment and fugitive emissions monitoring, thief hatches or other openings on a controlled storage vessel, compressors, instruments and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions

¹⁴⁰ The Oil and Natural Gas Sector NSPS (40 CFR 60, subpart OOOO) specifically defines "equipment" relative to standards for equipment leaks of VOC from onshore natural gas processing plants. As used in this chapter, the term "equipment" is used in a broader context and is not meant to be limited by the manner in which the term is currently used in subpart OOOO.

components, insofar as the natural gas and associated VOC emissions discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

9.2.2. Emission Data and Emission Factors

9.2.2.1 Summary of Major Studies and Emission Factors

In April of 2014, we published a white paper¹⁴¹ which summarized our current understanding of VOC fugitive emissions at onshore oil and natural gas production, processing and transmission and storage facilities (referred to herein as the “equipment leaks white paper”). The equipment leaks white paper also outlined our understanding of the available mitigation techniques (practices and equipment) available to reduce these emissions along with the cost and emission reduction potential of these practices and technologies.

The equipment leaks white paper provided a summary of fugitive emission studies at oil and natural gas well sites and gathering and boosting stations in the production segment. Throughout the development of this CTG, the EPA evaluated a variety of emissions data and emission reduction options for fugitive emissions. Many of the studies in the equipment leaks white paper were consulted. Table 9-1 presents a list of the studies consulted along with an indication of the type of information contained in each study.

Table 9-1. Major Studies Reviewed for Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options ^m
Protocol for Equipment Leak Emission Estimates ^a	EPA	1995	None	X	X
Methane Emissions from the Natural Gas Industry: Equipment Leaks ^b	EPA/GRI	1996	Nationwide	X	X
Greenhouse Gas Reporting Program ^c	EPA	2013	Facility	X	
Inventory of Greenhouse Gas Emissions and Sinks ^d	EPA	Annual	Regional	X	
Measurements of Methane Emissions at Natural Gas	Multiple Affiliations,	2013	Nationwide	X	X

¹⁴¹ U.S. EPA. *Oil and Natural Gas Sector Leaks*, OAQPS. Research Triangle Park, NC. April 2014. Available at <http://www.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf>.

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options ^m
Production Sites in the United States ^c	Academic and Private				
City of Fort Worth Natural Gas Air Quality Study, Final Report ^f	City of Fort Worth	2011	Fort Worth, TX	X	X
Measurements of Well Pad Emissions in Greeley, CO ^g	ARCADIS/Sage Environmental Consulting/ EPA	2012	Colorado	X	X
Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras ^h	Carbon Limits	2013	Canada and the U.S.	X	X
Mobile Measurement Studies in Colorado, Texas, and Wyoming ⁱ	EPA	2012 and 2014	Colorado, Texas, and Wyoming	X	X
Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries ^j	ICF International	2014	Nationwide	X	X
Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants ^k	Clearstone Engineering, Ltd.	2002	4 gas processing plants	X	X
Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites ^l	Clearstone Engineering, Ltd.	2006	5 gas processing plants, 12 well sites	X	X

^a U.S. Environmental Protection Agency. *Protocol for Equipment Leak Emission Estimates*. Office of Air Quality Planning and Standards. Research Triangle Park, NC. November 1995. EPA-453/R-95-017. Available at <http://www.epa.gov/ttn/chief/efdocs/equiplks.pdf>.

^b U.S. Environmental Protection Agency/GRI. Research and Development, *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*. June 1996 (EPA-600/R-96-080h).

^c U.S. Environmental Protection Agency. Greenhouse Gas Reporting Program. (Annual Reporting; Current Data Available for 2011-2013). 2014.

^d U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. <https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html>.

^e Allen, David, T., et al. *Measurements of methane emissions at natural gas production sites in the United States*. Proceedings of the National Academy of Sciences (PNAS) 500 Fifth Street, NW NAS 340 Washington, DC 20001 USA. October 29, 2013. 6 pgs.

^f ERG and Sage Environmental Consulting, LP. *City of Fort Worth Natural Gas Air Quality Study, Final Report*. Prepared for the City of Fort Worth, Texas. July 13, 2011. Available at <http://fortworthtexas.gov/gaswells/default.aspx?id=87074>.

^g Modrak, Mark T., et al. *Understanding Direct Emissions Measurement Approaches for Upstream Oil and Gas Production Operations*. Air and Waste Management Association 105th Annual Conference and Exhibition, June 19-22, 2012 in San Antonio, Texas.

^h Carbon Limits. *Quantifying cost-effectiveness of systematic Leak Detection and Repair Programs using Infrared cameras*. December 24, 2013. Available at http://www.catf.us/resources/publications/files/CATF-Carbon_Limits_Leaks_Interim_Report.pdf.

ⁱ Thoma, Eben D., et al. *Assessment of Methane and VOC Emissions from Select Upstream Oil and Gas Production Operations Using Remote Measurements, Interim Report on Recent Studies*. Proceedings of the 105th Annual Conference of the Air and Waste Management Association, June 19-22, 2012 in San Antonio, Texas.

^j ICF International. *Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries*. ICF International (Prepared for the Environmental Defense Fund). March 2014.

^k Clearstone Engineering Ltd. *Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants*. June, 2002.

^l Clearstone Engineering Ltd. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*. March 2006.

^m An “X” in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

9.2.2.2 Model Plants

Facilities in the oil and natural gas industry consist of a variety of combinations of process equipment and components. This is particularly true in the production segment of the industry, where “surface sites” can vary from sites where only a wellhead and associated piping is located to sites where a substantial amount of separation, treatment, and compression occurs. In order to conduct analyses to be used in evaluating potential options to reduce fugitive emissions from well sites and gathering and boosting stations, a model plant approach was used. The following sections discuss the creation of these model plants.

Oil and Natural Gas Production Well Sites

Oil and natural gas production varies from one site to the next. Some production sites may include only a single wellhead that is extracting oil or natural gas from the ground, while other sites may include multiple wellheads attached to a well site. A well site is a site where the production, extraction, recovery, lifting, stabilization, separation, and/or treating of petroleum and/or natural gas (including condensate) occurs. These sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) that have associated components that may be sources of fugitive emissions

associated with these operations. A well site can serve one well on a pad or multiple wells on a pad. Therefore, the number of components with potential for fugitive emissions can vary depending on the number of wells at the site.

Model plants were developed using the average number of wells associated with a well site using data from the Drillinginfo HPDI database.¹⁴² Baseline fugitive emissions from well sites depend upon the quantity of equipment and components, which in turn is based on this estimate of wells per pad. To estimate the average number of wells co-located on the same site as a new well completion or recompletion, the EPA developed a pair of algorithms that identified new and existing wells within a given distance of a new well completion or recompletion. This distance was assumed to represent the distance that, if other wells were within the distance, the wells would likely be co-located with the well under examination on the same site. The algorithms were written in the open source R programming language.¹⁴³

The HPDI well and production data used to estimate the average number of well co-located on a well site drew upon the latitude and longitude of new well completions and recompletions as well as the coordinates of all wells producing oil or natural gas in 2012. The first algorithm estimated the distances between each new completion and recompletion and all producing wells, which also includes wells newly completed and producing in 2012 within the same county as the completed well. If the distance between the completed well and producing well was less than the assumed size of a typical well site, we assumed the two wells were co-located. This algorithm progressed county by county across the U.S. where oil and natural gas production occurred in 2012 to identify all co-located wells in the U.S. The number of new well completions and recompletions in 2012 was about 44,000, which includes oil and natural gas wells whether they were hydraulically fractured or not. Wells producing in 2012 numbered about 1.27 million. The second algorithm processed the results of the first such that a well can only appear once on a modelled well site.

Once these algorithms were complete and produced a results file, we converted the results into a “kml” file that enabled the visual inspection of the results within Google Earth. We did not visually inspect every site in the U.S. linked to a 2012 completion or recompletion as

¹⁴² Drilling Information, Inc. 2011. *DI Desktop*. 2011 Production Information Database.

¹⁴³ See the website <<http://www.r-project.org/>> for more information on R (The R Project for Statistical Computing). R is a free software environment for statistical computing and graphics.

they numbered greater than 20,000. Instead, we examined sites randomly across a range of oil and natural gas production regions. The results of this visual examination indicated the algorithms were functioning as intended.

We estimated the number of wells per site assuming sites of one, two and three acres, based upon input from petroleum industry data analysts. Table 9-2 shows the high-level results of these analyses.

Table 9-2. Estimated Average Number of Wells per Site of New Well Completion in 2012

Assumed Well Site Size	No. of Well Sites	No. of Wells at Sites	Average of Wells Per Site
One Acre	29,213	50,599	1.73
Two Acres	28,938	52,422	1.81
Three Acres	28,710	53,981	1.88

For assumed well sites of two acres, the analysis identified 28,938 independent well sites that contained 52,422 wells (including both single and multi-well sites). The total number of wells identified as being co-located with new well completions and recompletions exceeds the total number of completions and recompletions because the sites include about 8,500 existing wells producing in 2012.

However, the high level summary presented in Table 9-3 masks variation by basins and well types. Table 9-3 presents more detail along these dimensions for the assumed two-acre well site.

Table 9-3. Estimated Average Number of Wells per Two-Acre Site of New Well Completions and Recompletions in 2012, by HPDI Basin and Type of Well (Oil or Natural Gas, Hydraulically Fractured or Not)

HPDI Basin	No. Of Sites	Oil Well Completions			Natural Gas Well Completions			Total
		HF	Not HF	All	HF	Not HF	All	
Los Angeles	23	N/A	13.07	13.07	N/A	N/A	N/A	13.07
Piceance	111	2.00	1.00	1.75	6.72	11.75	10.14	9.84
Arctic Ocean	2	N/A	5.50	5.50	N/A	N/A	N/A	5.50
Green River	164	2.23	1.57	2.01	4.37	1.13	4.19	3.88
Unidentified	226	1.18	3.57	3.38	1.00	1.77	1.44	3.22
San Joaquin Basin	1,745	1.56	3.46	3.21	2.61	1.42	2.24	3.16
Arkoma Basin	374	4.00	1.33	2.00	3.06	1.00	3.01	3.00
Denver Julesburg	826	2.63	3.10	2.75	1.48	3.14	1.72	2.46
Ft. Worth Basin	1,305	2.05	1.86	1.91	3.27	1.10	2.93	2.33
Central Western Overthrust	7	1.50	N/A	1.50	2.60	N/A	2.60	2.29
Ventura Basin	1	N/A	2.00	2.00	N/A	N/A	N/A	2.00
Arctic Slope	42	N/A	2.13	2.13	N/A	1.65	1.65	1.99
Ouachita Folded Belt	181	2.01	1.90	1.99	1.50	1.00	1.43	1.97
Salina Basin	13	N/A	1.92	1.92	N/A	N/A	N/A	1.92
Palo Duro Basin	81	1.42	1.97	1.89	1.00	N/A	1.00	1.86
Uinta	548	1.16	1.33	1.32	N/A	3.33	3.33	1.83
Texas & Louisiana Gulf Coast	3,994	2.03	1.82	1.96	1.37	1.14	1.28	1.79
Central Kansas Uplift	450	N/A	1.78	1.78	N/A	1.53	1.53	1.77
Permian Basin	8,507	1.66	1.76	1.69	1.50	1.57	1.52	1.68
Sedgwick Basin	240	N/A	1.67	1.67	1.67	1.55	1.55	1.62
Las Animas Arch	25	1.00	1.64	1.61	N/A	1.50	1.50	1.60
Nemaha Anticline	38	N/A	1.55	1.55	N/A	N/A	N/A	1.55
Arkla Basin	811	1.09	1.57	1.49	1.47	1.09	1.42	1.46
Chautauqua Platform	461	1.36	1.57	1.49	1.64	1.03	1.35	1.45
Cook Inlet Basin	9	N/A	2.00	2.00	N/A	1.29	1.29	1.44
Appalachian	2,496	1.14	1.05	1.10	2.28	1.10	1.77	1.43
Williston	1,570	1.36	1.00	1.35	1.43	1.00	1.39	1.35
Cherokee Basin	271	1.17	1.29	1.29	N/A	1.69	1.69	1.35
San Juan	158	1.00	1.00	1.00	1.38	1.20	1.37	1.31
East Texas Basin	618	1.25	1.74	1.52	1.22	1.06	1.21	1.31
Forest City Basin	172	N/A	1.28	1.28	N/A	N/A	N/A	1.28
Anadarko Basin	2,663	1.17	1.77	1.37	1.09	1.29	1.13	1.27
South Oklahoma Folded Belt	167	1.17	1.36	1.30	1.11	1.11	1.11	1.24
Chadron Arch	49	N/A	1.22	1.22	N/A	N/A	N/A	1.22

HPDI Basin	No. Of Sites	Oil Well Completions			Natural Gas Well Completions			Total
		HF	Not HF	All	HF	Not HF	All	
Sacramento Basin	13	N/A	N/A	N/A	N/A	1.15	1.15	1.15
Mississippi & Alabama Gulf Coast	132	1.00	1.18	1.14	1.00	1.00	1.00	1.14
Central Montana Uplift	10	1.13	1.00	1.10	N/A	N/A	N/A	1.10
Big Horn	30	1.10	1.11	1.11	1.00	N/A	1.00	1.10
Powder River	232	1.15	1.03	1.12	1.05	1.00	1.04	1.10
Sweet Grass Arch	17	1.00	1.08	1.05	1.50	1.00	1.33	1.10
Paradox	13	1.00	1.10	1.09	1.00	N/A	1.00	1.08
Black Warrior Basin	57	1.00	1.00	1.00	1.00	1.75	1.07	1.05
Wind River	63	1.00	1.02	1.02	1.00	1.00	1.00	1.02
Wasatch Uplift	1	N/A	1.00	1.00	N/A	N/A	N/A	1.00
North Park	2	1.00	1.00	1.00	N/A	N/A	N/A	1.00
Raton	20	N/A	N/A	N/A	1.00	1.00	1.00	1.00
Grand Total	28,938	1.64	1.99	1.79	1.90	1.76	1.86	1.81

The data presented in Table 9-3 indicates that the concentration of wells at production sites varies greatly by basin. However, the analysis also indicates that most wells sites have relatively few or no co-located wells, which brings the national average of wells per new completion or recompletion site to 1.81 for the two-acre well site. While the analysis shows variation by basin, at the national level, there is relatively little variation across oil and natural gas well completion sites and whether the new wells were completed or recompleted using hydraulic fracturing. For example, oil well sites averaged 1.79 wells per site while natural gas wells averaged 1.86.

As a result of this analysis, we decided to use the two-acre well site as the assumed maximum size of a site to estimate the number of wells co-located at sites of new completions and recompletions. Also, to simplify analysis of costs and emissions at well sites, we rounded the 1.81 national average wells per site to 2.

While we are confident that the assumed two-acre well site is a reasonable size to capture most co-located wells in 2012, it is by no means a perfect assumption. First, industry and state regulatory trends indicate that well drilling will likely become increasingly concentrated on sites, potentially leading to an increase in the average number of wells per well site. However, it is not possible at this point to forecast this increasing concentration, especially with the variations by

fields described above. Also, it is possible that two acres is too small to accurately estimate the number of co-located wells for large well sites in some fields. As a result, the algorithms might result in an underestimate of the average number of wells at a site and identify more than one site when in actuality there is only one. Alternatively, the assumed two acres might overestimate the size of sites in some fields and, as a result, pull in more than one site, overestimating the number of wells on the site. We also noted that the latitude and longitude values on many wells were likely incorrect or exact duplicates of other wells. Despite these caveats, we believe that the well site analysis described here produces a reasonable estimate of national average of number of wells on new well completion and recompletion sites in 2012. Therefore, based on this analysis, the model plants for oil and natural gas well sites are based on a well site with 2 wells.

Baseline model plant emissions for natural gas and oil production well sites were calculated using the fugitive emissions equipment counts from the GHG Inventory, derived from GHGRP, EPA/GRI and 40 CFR part 98, subpart W tables, and the component oil and natural gas production emission factors from AP-42.¹⁴⁴ Annual emissions were calculated assuming 8,760 hours of operation each year. We used equipment count data from the EPA GHG Inventory to calculate the average counts of production equipment located at a well site. The types of production equipment located at a well site include: gas wellheads, separators, meters/piping, heaters, and dehydrators. The types of components that are associated with these production equipment types include: valves, connectors, open-ended lines, and pressure relief valves. Component counts for each of the equipment items were calculated using the average component counts for gas production equipment in the Eastern U.S. and the Western U.S. Fractions of components were rounded up to the nearest integer.

For natural gas well sites, the model plant was developed using the average equipment and fugitive emissions components counts for natural gas production data from the EPA/GRI report and the 2016 GHG Inventory. The average equipment count for a natural gas well was estimated by using the average equipment counts per well in the 2016 GHG Inventory (based on GHGRP data), and by weighing the average component counts per equipment for the Eastern and Western U.S. data sets for gas production equipment. This resulted in 2 separators, 3 meters/piping, 1 in-line heater, and 1 dehydrator per well. The total natural gas well site

¹⁴⁴ U.S. Environmental Protection Agency. *Protocol for Equipment Leak Emission Estimates*. Table 2-4. November 1995. EPA-453/R-95-017.

equipment counts were calculated by multiplying the average well equipment values by the average number of wells per well site (2), and rounding the product to the nearest integer. Average component counts for each of the equipment items were calculated using the average component counts for production equipment in the Eastern U.S. and the Western U.S. from the EPA/GRI study. The total number of fugitive emissions components was calculated by multiplying the rounded equipment counts by the component count per equipment and rounding to the nearest integer. Table 9-4 presents a summary of the fugitive emissions component counts for natural gas well sites.

For oil well sites, two model plants were developed in order to account for emissions variability. One oil well model plant was developed for oil wells with a gas-to-oil ration less than 300 standard cubic feet of gas per stock barrel of oil (GOR less than 300) and another model plant was developed for oil wells with a gas-to-oil ratio greater than or equal to 300 standard cubic feet of gas per stock of barrel oil (GOR greater than or equal to 300).

The equipment count for the oil well model plant with a GOR less than 300 consists of 2 oil wellheads, 1 separator, 1 header and 1 heater/treater. These equipment counts were obtained from 2016 GHG Inventory data. The component counts for these equipment types were obtained from Table W-1C of subpart W and are the weighted average component counts for onshore production equipment in the Eastern U.S. and Western U.S.

The equipment count for the oil well model plant with a GOR greater than or equal to 300 consists of 2 oil wellheads, 1 separator, 1 header and 1 heater/treater and 3 meters/piping. These equipment counts for separators, headers, and heater/treaters were obtained from the 2016 GHG Inventory data for petroleum systems, while the meter/piping counts were obtained from the 2016 GHG Inventory data for natural gas systems to reflect gas production at the sites.

The component counts for these equipment types were obtained from Table W-1C of subpart W for all but meters/piping, which were obtained from Table W-1B of subpart W. The component counts are the weighted average component counts for onshore production equipment in the Eastern U.S. and Western U.S. The total number of fugitive emissions components for oil well sites equipment (for both model plants) was calculated by multiplying the rounded equipment counts by the component count per piece of equipment and rounding to the nearest integer. Table 9-5 presents a summary of the fugitive emissions component counts for oil well site model plants.

Table 9-4. Average Fugitive Emissions Component Count for Natural Gas Well Site Model Plant

Equipment	Model Plant Equipment Counts	Average Component Count per Equipment ^a				Average Component Count per Model Plant			
		Valves	Connectors	OELs	PRVs	Valves	Connectors	OELs	PRVs
Gas Wellheads	2	9.5	37.0	0.7	0.0	19.0	74.0	1.4	0.0
Separators	2	21.6	68.5	3.7	1.2	43.2	137.0	7.4	2.4
Meters/Piping	3	12.9	47.8	0.5	0.5	38.7	143.4	1.5	1.5
In-Line Heaters	1	14.0	65.0	2.0	1.0	14.0	65.0	2.0	1.0
Dehydrators	1	24.0	90.0	2.0	2.0	24.0	90.0	2.0	2.0
Total						138.9	509.4	14.3	6.9
Rounded up Total						139	510	15	7.0

^a Data Source: EPA/GRI. *CH₄ Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

Table 9-5. Average Fugitive Emissions Component Count for Oil Well Site Model Plants

Production Equipment	Model Plant Production Equipment Counts	Average Component Count Per Unit of Production Equipment ^a					Average Component Count Per Model Plant				
		Valves	Flanges	Connectors	OELs	PRVs	Valves	Flanges	Connectors	OELs	PRVs
Oil Well Model Plant (< 300 GOR) ^a											
Oil Wellheads	2	5	10	4	0	1	10	20	8	0	2
Separators	1	6	12	10	0	0	6	12	10	0	0
Headers	1	5	10	4	0	0	5	10	4	0	0
Heater/Treaters	1	8	12	20	0	0	8	12	20	0	0
Total							29	54	42	0	2
Oil Well Model Plant (≥ 300 GOR) ^b											
Oil Wellheads	2	5	10	4	0	1	10	20	8	0	2
Separators	1	6	12	10	0	0	6	12	10	0	0
Headers	1	5	10	4	0	0	5	10	4	0	0
Heater/Treaters	1	8	12	20	0	0	8	12	20	0	0
Meters/Piping	3	12.9	0	47.8	0.5	0.5	39	0	144	2	2
Total							68	54	186	2	4

^a Oil well (<300 GOR) component counts obtained from 40 CFR Part 98, subpart W, Table W-1C.

^b Oil well (≥300 GOR) component counts obtained from 40 CFR Part 98, subpart W, Tables W-1B and W-1C.

The baseline emissions for the natural gas well site and oil well model plants were calculated using equipment counts for the natural gas well site model plant and the oil and natural gas production AP-42 total organic compound (TOC) emission factors. Annual emissions were calculated assuming 8,760 hours of operation each year. The TOC emissions were converted to VOC using VOC/TOC weight ratios in the 2011 Gas Composition Memorandum.¹⁴⁵ The fugitive VOC emissions for the natural gas well site model plant were determined to be 1.53 tpy of VOC. The fugitive emissions for the oil well site model plant with a GOR less than 300 was determined to be 0.33 tpy of VOC. The fugitive emissions for the oil well site model plant with a GOR greater than or equal to 300 was determined to be 0.73 tpy of VOC. The VOC emission estimates were used to evaluate the potential emission reductions and cost of control of a fugitive emission reduction program. Table 9-6 presents the emission factors for the natural gas and oil production segments. A summary of the equipment counts, average TOC emission factors and VOC emissions for natural gas well and oil well sites are provided in Tables 9-7 and 9-8, respectively.

Table 9-6. Oil and Natural Gas Production Operations Average TOC Emission Factors

Component Type	Component Service	TOC Emission Factor^a (kg/hr/source)
Valves	Gas	4.5E-03
Flanges	Gas	3.9E-04
Connectors	Gas	2.0E-04
OEL	Gas	2.0E-03
PRV	Gas	8.8E-03

^a Data Source: EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017)

¹⁴⁵ Memorandum to Bruce Moore from Heather Brown. *Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking*. EC/R, Incorporated. July, 2011.

Table 9-7. Estimated Fugitive VOC Emissions for Natural Gas Production Model Plant

Natural Gas Well Site Model Plant Component	Model Plant Component Count^a	Uncontrolled TOC Emission Factor^b (kg/hr/comp)	Uncontrolled VOC Emissions (tpy)^c
Valves	139	0.0045	1.166
Connectors	510	0.0002	0.190
OELs	15	0.002	0.056
PRVs	7	0.0088	0.115
Total			1.53

^a Fugitive emissions component count values for model plant are based on a 2-wellhead site and are rounded to the nearest integer.

^b TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.

^c VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from the 2011 Gas Composition Memorandum.

Table 9-8. Estimated Fugitive VOC Emissions for Oil Well Site Model Plants

Oil Well Site Model Plant Component	Model Plant Component Count^a	Uncontrolled Emission Factor^b (kg/hr/comp)	Uncontrolled VOC Emissions (tpy)^c
<i>Oil Well Model Plant (< 300 GOR)</i>			
Valves	29	0.0045	0.243
Flanges	54	0.00039	0.039
Connectors	42	0.0002	0.016
OELs	0	0.002	0
PRVs	2	0.0088	0.033
Total			0.33
<i>Oil Well Model Plant (≥ 300 GOR)</i>			
Valves	68	0.0045	0.571
Flanges	54	0.00039	0.039
Connectors	186	0.0002	0.069
OELs	2	0.002	0.007
PRVs	4	0.0088	0.066
Total			0.75

^a Fugitive emissions component count values for model plant are based on a 2-wellhead pad and are rounded to the nearest integer.

^b TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.

^c VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from the 2011 Gas Composition Memorandum.

Gathering and Boosting Stations

Gathering and boosting stations are sites that collect natural gas from well sites and direct them to the natural gas processing plants. These stations have similar equipment to well sites; however they are not directly connected to the wellheads. The EPA/GRI document does not have specific equipment counts for the gathering and boosting segment, but does include equipment counts for gathering compressors within the oil and natural gas production data. To estimate the equipment at a gathering and boosting model plant, the weighted averages of equipment counts

for the Eastern and Western U.S. data sets for onshore production equipment were calculated. The weighted averages of the data sets were determined to be 11 separators, 7 meters/piping, 5 gathering compressors, 7 in-line heaters, and 5 dehydrators. These average equipment counts were used to create the model plant for gathering and boosting stations. The components for gathering compressors were included in the model plant total counts, but the compressor seals were excluded. Compressor seals are addressed in chapter 5 of this document. Table 9-9 presents a summary of the fugitive emissions component counts for oil and gas gathering and boosting stations.

Baseline emissions were calculated using the component counts and the TOC emission factors for oil and natural gas production (See Table 9-6). Table 9-10 summarizes the baseline emissions for gathering and boosting stations. The average fugitive emissions from a gathering and boosting station were determined to be 9.8 tpy of VOC. The VOC emission estimate was used to evaluate the potential emission reductions and cost of control of a fugitive emissions reduction program.

Table 9-9. Average Component Count for the Oil and Natural Gas Production Gathering and Boosting Station Model Plant

Equipment	Model Plant Equipment Counts	Average Component Count per Equipment ^a				Average Component Count per Model Plant			
		Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves
Separators	11	22	68	4	1	242	748	44	11
Meters/Piping	7	13	48	0	0	91	336	0	0
Gathering Compressors	5	71	175	3	4	355	875	15	20
In-Line Heaters	7	14	65	2	1	98	455	14	7
Dehydrators	5	24	90	2	2	120	450	10	10
Total						906	2,864	83	48

^a Data Source: EPA/GRI. Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Tables 4-4 and 4-7, June 1996. (EPA- 600/R-96-080h).

Table 9-10. Estimated Fugitive TOC and VOC Emissions for the Oil and Natural Gas Production Gathering and Boosting Station Model Plant

Component	Model Plant Component Count ^a	Component TOC Emission Factor (kg/hr/ component) ^b	VOC Emissions (tons/yr) ^c
Valve	906	0.0045	7.6
Connectors	2,864	0.0002	1.1
OEL	83	0.002	0.3
PRV	48	0.0088	0.8
Total			9.8

^a Component counts from Table 9-9.

^b TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.

^c VOC emissions are the baseline which were calculated using 0.193 weight ratio for VOC/TOC obtained from the 2011 Gas Composition Memorandum.

9.3 Available Controls and Regulatory Approaches

9.3.1 Available VOC Emission Control Options

The EPA has determined that fugitive emissions from components are a significant source of VOC emissions from well sites and gathering and boosting stations. Based on the review of public and peer review comments on the equipment leaks white paper and the Colorado and Wyoming state rules, the EPA has identified two options for reducing fugitive VOC emissions from components: a fugitive emissions monitoring program based on the use of OGI leak detection combined with repair of fugitive emission components, and a leak monitoring program based on individual component monitoring using Method 21 for leak detection combined with repair of fugitive emission components. These options, as currently being used by industry to reduce fugitive emissions in the oil and natural gas industry, are described below.

9.3.1.1 *Fugitive Emission Detection and Repair with Optical Gas Imaging* Description

The reduction of fugitive emissions from oil and natural gas well sites and gathering and boosting stations involves the development and implementation of a fugitive emissions monitoring plan that covers the collection of fugitive emissions components at well sites or gathering and boosting stations. Under this option, monitoring is conducted using OGI, and the company develops and implements a monitoring plan that covers the collection of fugitive

emissions components at well sites or compressor stations within a company-defined area. An example monitoring plan would include inspection of the collection of all fugitive emissions components, such as connectors, open-ended lines/valves, pressure relief devices, closed vent systems, compressors, and thief hatches on controlled storage vessels. The plan would include provisions to repair or replace fugitive emissions components if evidence of fugitive emissions is discovered during the OGI survey (e.g., any visible emissions from a fugitive emissions component observed using OGI).

Control Effectiveness

Potential emission reduction percentages from the implementation of an OGI monitoring program varies from 40 to 99 percent.¹⁴⁶ The data supporting these emission reduction percentages are based on the gathering of individual OGI surveys at various oil and natural gas industry segment sites. The variation in the percent reductions from these OGI surveys generally depended on whether large fugitive emission sources were found (e.g., open thief hatches, open dump valves, etc.) during the OGI survey and assumptions made by the authors. However, the studies supporting these emission reduction percentages did not provide information on the potential emission reductions from the implementation of an annual, semiannual, quarterly, or monthly OGI monitoring and repair program. A report was found, after the publication of the white paper, from the Colorado Air Quality Control Commission,¹⁴⁷ which estimated (1) 40 percent reduction for annual OGI monitoring for well production tank batteries with uncontrolled VOC emissions of greater than 6 tpy or less than or equal to 12 tpy; (2) 60 percent reduction for quarterly OGI monitoring for well production tank batteries with uncontrolled VOC emissions of greater than 12 tpy and less than or equal to 50 tpy; and (3) 80 percent reduction for monthly OGI monitoring at well production tank batteries with uncontrolled VOC emissions greater than 50 tpy.

From the review of the studies in the white paper and the Colorado Economic Impact Analysis, we expect the emission reductions from the implementation of an OGI monitoring and repair program to vary depending on the frequency of monitoring. As noted above, Colorado

¹⁴⁶ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Leaks*, Office of Air Quality Planning and Standards. Research Triangle Park, NC. April 2014. Available at <http://www.epa.gov/airquality/oilandgas/2014papers>.

¹⁴⁷ Colorado Air Quality Control Commission, *Cost-Benefit Analysis Submitted Per § 24-4-103(2.5), C.R.S. For Proposed Revisions to Colorado Air Quality Control Commission Regulations Number 3 (5 CCR 1001-5) and Regulation Number 7 (5 CCR 1001-9)*. February 7, 2014.

estimated that monthly monitoring would achieve 80 percent at well production tank batteries with an uncontrolled VOC emission rate of greater than 50 tpy. We believe, based on our review of the studies, monthly monitoring should achieve much higher emission reductions. Based on information in the studies and EPA's engineering judgment, the potential emission reduction percentages are estimated to be 40 percent for annual monitoring, 60 percent for semiannual monitoring, and 80 percent for quarterly monitoring.

Data from the EPA Protocol document estimates monthly Method 21 monitoring to achieve 87 percent reductions at a leak definition of 10,000 ppm and 92 percent reductions at a leak definition of 500 ppm. Potential emission reductions for annual, semiannual and quarterly monitoring frequencies were calculated using the data from the EPA Protocol document.¹⁴⁸ For quarterly monitoring, the Method 21 data from the EPA Protocol document estimates a 67 percent reduction at a leak definition of 10,000 ppm and an 83 percent reduction at a leak definition of 500 ppm. Using Method 21 data from the EPA Protocol document, we estimated the percent reductions from semiannual monitoring to be 55 percent at a leak definition of 10,000 ppm and 75 percent reduction at a leak definition of 500 ppm. The potential emission reduction percentages for annual monitoring were calculated to be 42 percent at a leak definition of 10,000 ppm and 68 percent at a leak definition of 500 ppm. The OGI camera is capable of viewing leaks at a 500 ppm level, and achieves similar emission reductions as a Method 21 monitoring program. Based on this information, we believe the expected emission reductions from an OGI monitoring and repair program falls somewhere in the 500 and 10,000 ppm range found in the Method 21 monitoring programs, but closer to the 500 ppm level.

A study performed by ICF¹⁴⁹ using data from subpart W, EPA/ GRI, City of Fort Worth Natural Gas Air Quality Study, UT Study - Methane Emissions in the Natural Gas Supply Chain: Production, UT Study - Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States Pneumatic Controllers, and Jonah Energy LLC WCCA Spring Meeting Presentation determined the Year 3 fugitive emission reductions from a quarterly LDAR program to be 78 percent. The data provided in the study supports 40, 60, 80 percent emission reductions for annual, semiannual and quarterly monitoring, respectively.

¹⁴⁸ Memorandum from Bradley Nelson, EC/R to Jodi Howard, EPA/OAQPS/SPPD, *Estimation of Potential Emission Reductions with the Implementation of a Method 21 Monitoring Program*. April 25, 2016.

¹⁴⁹ ICF International. *Leak Detection and Repair Cost-Effectiveness Analysis*. Prepared for Environmental Defense Fund. December 4, 2015. Revised May 2, 2016.

On the basis of the analysis and the data described here, it was concluded that an OGI monitoring program in combination with a repair program can reduce fugitive methane and VOC emissions from these segments by 40 percent on an annual frequency, 60 percent on a semiannual frequency and 80 percent on a quarterly frequency, as well as minimize the loss of salable gas.

To be conservative, we performed a sensitivity analysis using the midpoint between the potential emission reductions that were calculated for each of the Method 21 monitoring frequencies at leak definitions of 10,000 ppm and 500 ppm, which were determined to be 55, 65, and 75 percent for annual, semiannual and quarterly monitoring, respectively. We then compared the potential emission reductions from 40, 60, 80 percent reductions with the Method 21 midpoint reduction percentages of 55, 65 and 75 and found that the annual methane and VOC emission reductions at each of the monitoring frequency intervals were comparable.¹⁵⁰

Cost Impacts

Costs (2012 dollars) for preparing an OGI emission monitoring and repair plan for a company-defined area (i.e., field or district) were estimated using hourly estimates for each of the monitoring and repair plan elements. The costs are based on the following assumptions:

- (1) Labor cost for each of the monitoring plan elements was estimated to be \$57.80 per hour.
- (2) Reading of the rule and instructions would take one person four hours to complete at a cost of \$231.
- (3) Development of a fugitive emission monitoring plan would take two and one half people a total of 60 hours to complete at a cost of \$3,468.
- (4) Initial activities planning are estimated to take two people a total of 8 hours per monitoring event. Cost for annual monitoring was estimated to be \$925, semiannual monitoring was estimated to be \$1,850, and quarterly monitoring was estimated to be \$3,699.
- (5) Notification of compliance status was estimated to take one person one hour to complete at a cost of \$58 for gathering and boosting stations. For companies that own and operate well sites, the cost of the notification of compliance was estimated to be \$58 per well site

¹⁵⁰ See Emission Reduction Comparison – Well Sites.xls, and Emission Reduction Comparison – Compressor Stations.xls in Docket Id. No. EPA-HQ-OAR-2015-0216 for more information.

for each company defined area, which is estimated to operate 22 well sites within the defined area for a total of \$1,272.

- (6) Cost of a Method 21 monitoring device of \$10,800; or cost for OGI monitoring using an outside contractor (assumed to be \$600 for a well site and \$2,300 for a gathering and boosting station for each survey).

Costs for implementing a fugitive emission monitoring plan for a company-defined area (i.e., field or district) were estimated for each of the monitoring and repair elements. The costs are based on the following assumptions:

- (1) Subsequent activities planning are estimated to take two people a total of 16 hours per monitoring event for well sites and two people a total of 24 hours for gathering and boosting stations. For well sites, this cost was divided among the total number of well sites in the company-defined area.
- (2) The cost for OGI monitoring using an outside contractor was assumed to be \$600 for a well site and \$2,300 for a gathering and boosting station for each survey.
- (3) Annual repair costs were estimated to be \$299 for well sites and \$3,436 for gathering and boosting stations per survey. These costs were estimated assuming that 1.18 percent of the components leak and 75 percent are repaired online and 25 percent are repaired offline.
- (4) Cost for resurvey of components assumes five minutes per leak at \$57.80 per hour for well sites and \$2.00 per leak for gathering and boosting stations. This is based on the assumption that a company purchases Method 21 instrumentation (estimated to be \$10,800¹⁵¹) and is able to perform the resurvey without needing contractors.
- (5) Preparation of annual reports was estimated to take one person a total of 4 hours to complete at a cost of \$231.

The initial setup cost or capital cost for well sites was calculated by summing up the costs for reading the air agency rule, development of fugitive emissions monitoring plan, initial activities planning, and notification of initial compliance status. The total capital cost of these activities was calculated to be \$16,696 per company-defined areas for annual monitoring,

¹⁵¹ Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA-HQ-OAR-2002-0037-0180.

\$17,620 per company-defined areas for semiannual monitoring and \$19,470 per company-defined areas for quarterly monitoring. Assuming that each company owns and operates 22 well sites within a company-defined area¹⁵², the capital cost per well site was estimated to be \$759 for annual monitoring, \$801 for semiannual monitoring and \$855 for quarterly monitoring. For gathering and boosting stations, the capital cost for reading the rule, development of fugitive emissions monitoring plan, initial activities planning notification of initial compliance status, and purchase of a Method 21 instrumentation device was calculated to be \$16,753 per facility. For gathering and boosting stations, the capital cost was assumed to be shared with other gathering and boosting stations within the company-defined area. These stations are estimated to be approximately 70 miles apart. Therefore, within a 210 mile radius of a central location, there would be an estimated seven gathering and boosting stations, and the capital cost for each of these stations was estimated to be \$2,393.

For well sites and gathering and boosting stations, the annual cost includes: subsequent activities planning, OGI survey by an outside contractor, cost of repair of fugitive emissions found, preparation and submittal of an annual report and the amortized capital cost over 8 years at 7 percent interest. For our analyses, we calculated the annual cost for annual, semiannual and quarterly OGI surveys. The annual cost for annual, semiannual, and quarterly OGI surveying (inclusive of contractor costs, cost of repair of fugitive emissions found, preparation and submittal of an annual report, and amortized capital cost over 8 years at 7 percent interest) was calculated for the production and processing segments. Tables 9-11 through 9-13 present summaries of the cost of control for VOC for the three OGI monitoring frequency options (i.e., annual, semiannual and quarterly).

¹⁵² The number of well sites owned and operated by companies was calculated using data from the Fort Worth study.

Table 9-11. Summary of the Model Plant VOC Cost of Control for the Annual OGI Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) ^a	Capital Cost (\$2012) ^b	Annual Cost (\$2012/year) ^c		Cost of Control (\$2012/ton)	
			Without savings	With savings ^d	Without savings	With savings ^d
Natural Gas Well Site	0.61	\$759	\$1,318	\$809	\$2,158	\$1,324
Oil Well Site (GOR < 300)	0.13	\$759	\$1,318	\$1,204	\$9,953	\$9,089
Oil Well Site (GOR ≥ 300)	0.30	\$759	\$1,318	\$1,063	\$4,380	\$3,533
Gathering and Boosting Station	3.91	\$2,393	\$7,777	\$4,518	\$1,990	\$1,156

^a Assumes 40 percent reduction with the implementation of annual IR camera monitoring.

^b The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program divided between an average of 22 well sites per company district. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between seven stations within a company-defined area.

^c Annual cost for well sites includes annual monitoring and repair cost of \$1,191 and amortization of the capital cost over 8 years at 7 percent interest. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of \$7,736 and amortization of the capital cost over 8 years at 7 percent interest.

^d Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as \$4 Mcf.

Table 9-12. Summary of the Model Plant VOC Cost of Control for the Semiannual OGI Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) ^a	Capital Cost (\$2012) ^b	Annual Cost (\$2012/year) ^c		Cost of Control (\$2012/ton)	
			Without savings	With savings ^d	Without savings	With savings ^d
Natural Gas Well Site	0.917	\$801	\$2,285	\$1,521	\$2,494	\$1,660
Oil Well Site (GOR < 300)	0.199	\$801	\$2,285	\$2,114	\$11,503	\$10,639
Oil Well Site (GOR ≥ 300)	0.451	\$801	\$2,285	\$1,903	\$5,062	\$4,215
Gathering and Boosting Station	5.86	\$2,393	\$13,534	\$8,646	\$2,309	\$1,475

^a Assumes 60 percent reduction with the implementation of semiannual IR camera monitoring.

^b The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program divided between an average of 22 well sites per company district. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between seven stations within a company-defined area.

^c Annual cost for well sites includes annual monitoring and repair cost of \$2,151 and amortization of the capital cost over 8 years at 7 percent interest. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of \$13,133 and amortization of the capital cost over 8 years at 7 percent interest.

^d Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as \$4 Mcf.

Table 9-13. Summary of the Model Plant VOC Cost of Control for the Quarterly OGI Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) ^a	Capital Cost (\$2012) ^b	Annual Cost (\$2012/year) ^c		Cost of Control (\$2012/ton)	
			Without savings	With savings ^d	Without savings	With savings ^d
Natural Gas Well Site	1.222	\$885	\$4,220	\$3,201	\$3,453	\$2,619
Oil Well Site (GOR < 300)	0.265	\$885	\$4,220	\$3,991	\$15,929	\$15,064
Oil Well Site (GOR ≥ 300)	0.602	\$885	\$4,220	\$3,710	\$7,010	\$6,163
Gathering and Boosting Station	7.81	\$2,393	\$25,049	\$18,532	\$3,205	\$2,371

^a Assumes 80 percent reduction with the implementation of quarterly IR camera monitoring.

^b The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of \$19,470 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between seven stations within a company-defined area.

^c Annual cost for well sites includes annual monitoring and repair cost of \$4,071 and amortization of the capital cost over 8 years at 7 percent interest. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of \$24,649 and amortization of the capital cost over 8 years at 7 percent interest.

^d Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as \$4 Mcf.

9.3.1.2 Fugitive Emission Detection and Correction with Method 21

Description

Another option that can be used to reduce fugitive emissions from well sites and gathering and boosting stations involves the development of a fugitive emissions monitoring plan using Method 21 to detect leaks from equipment and components. The plan would incorporate surveying of components at a specified interval and repair threshold using a Method 21 instrument, which also includes following the Method 21 requirements for monitoring, along with repair, recordkeeping and reporting requirements.

The plan would also include provisions for repair or replacement of components if evidence of fugitive emissions are discovered during the survey. The monitoring plan would include inspection of all fugitive emission components and would require repair where evidence

of fugitive emissions is discovered (as soon as practicable, but generally no later than 30 calendar days after the Method 21 survey). In addition, all repairs or replacement of components would be re-surveyed immediately after repair or replacement to ensure the fugitive emissions are below the specified repair threshold.

A facility can use a company-defined area fugitive emissions monitoring plan that covers the collection of fugitive emission components at well sites and gathering and boosting stations. By using a company-defined area, owners and operators have flexibility in developing monitoring plans and determining which company-defined area can be covered under the specifications outlined in one monitoring plan, for ease of implementation and compliance.

Control Effectiveness

Potential control efficiencies for Method 21 monitoring were estimated to be 42 to 83 percent depending on repair threshold and monitoring frequency in the 2016 NSPS. The Method 21 control options included repair thresholds of 10,000 and 500 parts per million (ppm) and annual, semiannual, and quarterly monitoring frequencies. Tables 9-14 through 9-16 present the summaries of the estimated emission reductions for annual, semiannual and quarterly Method 21 monitoring for the two repair thresholds for the well site and the gathering and boosting station model plants.

Cost Impacts

Costs (2012 dollars) for preparing and implementing a fugitive emission monitoring plan for a company-defined area (i.e., field or district) were estimated using hourly estimates for each of the plan elements. The costs are based on the following assumptions:

- (1) Labor cost for each of the monitoring plan elements was estimated to be \$57.80 per hour.
- (2) Reading of the air agency rule and instructions would take one person four hours to complete at a cost of \$231.20.
- (3) Development of a fugitive emission monitoring plan would take two and one half people a total of 60 hours to complete at a cost of \$3,468.
- (4) Initial activities planning are estimated to take two people a total of 16 hours per monitoring event. Cost for annual monitoring was estimated to be \$925, semiannual monitoring was estimated to be \$1,850, and quarterly monitoring was estimated to be \$3,699.

Table 9-14. Summary of the Model Plant VOC Cost of Control for the Annual Method 21 Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) ^a	Capital Cost (\$2012) ^b	Annual Cost (\$2012/year) ^c		Cost of Control (\$2012/ton)	
			Without savings	With savings ^d	Without savings	With savings ^d
10,000 ppm Repair Threshold						
Natural Gas Well Site	.645	\$1,418	\$2,300	\$1,762	\$3,568	\$2,734
Oil Well Site (GOR < 300)	0.14	\$1,418	\$2,300	\$2,179	\$16,459	\$15,595
Oil Well Site (GOR ≥ 300)	0.318	\$1,418	\$2,300	\$2,031	\$7,243	\$6,396
Gathering and Boosting Station	4.12	\$4,283	\$9,803	\$6,365	\$2,378	\$1,544
500 ppm Repair Threshold						
Natural Gas Well Site	1.043	\$1,418	\$2,300	1,430	\$2,204	\$1,371
Oil Well Site (GOR < 300)	0.226	\$1,418	\$2,300	\$2,104	\$10,169	\$9,305
Oil Well Site (GOR ≥ 300)	0.514	\$1,418	\$2,300	\$1,865	\$4,475	\$3,628
Gathering and Boosting Station	6.67	\$4,283	\$9,803	\$4,239	\$1,469	\$635

^a Assumes 42 percent reduction at 10,000 ppm repair threshold and 68 percent reduction at 500 ppm repair threshold with the implementation of annual Method 21 monitoring.

^b The capital cost for oil and natural gas well sites and gathering and boosting stations includes the cost of implementing the monitoring program which includes reading the rule, developing and implementing a monitoring plan (including initial activities planning), notification of initial compliance status, and purchase of a Method 21 monitoring device.

^c Annual cost for oil and natural gas well sites and gathering and boosting stations includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7 percent interest.

^d Recovery credits for oil and natural gas well sites were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as \$4 Mcf.

Table 9-15. Summary of the Model Plant VOC Cost of Control for the Semiannual Method 21 Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) ^a	Capital Cost (\$2012) ^b	Annual Cost (\$2012/year) ^c		Cost of Control (\$2012/ton)	
			Without savings	With savings ^d	Without savings	With savings ^d
10,000 ppm Repair Threshold						
Natural Gas Well Site	0.837	\$1,460	\$3,907	\$3,209	\$4,667	\$3,833
Oil Well Site (GOR < 300)	0.181	\$1,460	\$3,907	\$3,750	\$21,530	\$20,666
Oil Well Site (GOR ≥ 300)	0.412	\$1,460	\$3,907	\$3,558	\$9,475	\$8,628
Gathering and Boosting Station	5.35	\$4,415	\$17,292	\$12,828	\$3,230	\$2,396
500 ppm Repair Threshold						
Natural Gas Well Site	1.152	\$1,460	\$3,907	\$2,946	\$3,392	\$2,558
Oil Well Site (GOR < 300)	0.250	\$1,460	\$3,907	\$3,691	\$15,648	\$14,784
Oil Well Site (GOR ≥ 300)	0.567	\$1,460	\$3,907	\$3,426	\$6,887	\$6,039
Gathering and Boosting Station	7.37	\$4,415	\$17,292	\$11,150	\$2,348	\$1,514

^a Assumes 55 percent reduction at 10,000 ppm repair threshold and 75 percent reduction at 500 ppm repair threshold with the implementation of semiannual Method 21 monitoring.

^b The capital cost for oil and natural gas well sites and gathering and boosting stations includes the cost of implementing the monitoring program, which includes reading the rule, developing and implementing a monitoring plan (including initial activities planning), notification of initial compliance status, and purchase of a Method 21 monitoring device.

^c Annual cost for oil and natural gas well sites and gathering and boosting stations includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7 percent interest.

^d Recovery credits for oil and natural gas well sites were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as \$4 Mcf.

Table 9-16. Summary of the Model Plant VOC Cost of Control for the Quarterly Method 21 Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) ^a	Capital Cost (\$2012) ^b	Annual Cost (\$2012/year) ^c		Cost of Control (\$2012/ton)	
			Without savings	With savings ^d	Without savings	With savings ^d
10,000 ppm Repair Threshold						
Natural Gas Well Site	1.030	\$1,544	\$7,121	\$6,262	\$6,196	\$6,083
Oil Well Site (GOR < 300)	0.223	\$1,544	\$7,121	\$6,928	\$31,906	\$31,042
Oil Well Site (GOR ≥ 300)	0.507	\$1,544	\$7,121	\$6,691	\$14,042	\$13,195
Gathering and Boosting Station	6.58	\$4,679	\$32,271	\$26,780	4,901	\$4,067
500 ppm Repair Threshold						
Natural Gas Well Site	1.26	\$1,544	\$7,121	\$6,070	\$5,651	\$4,817
Oil Well Site (GOR < 300)	0.273	\$1,544	\$7,121	\$6,885	\$26,067	\$25,202
Oil Well Site (GOR ≥ 300)	0.621	\$1,544	\$7,121	\$6,595	\$11,472	\$10,624
Gathering and Boosting Station	8.06	\$4,679	\$32,271	\$25,550	\$4,004	\$3,170

^a Assumes 67 percent reduction at 10,000 ppm repair threshold and 83 percent reduction at 500 ppm repair threshold with the implementation of quarterly Method 21 monitoring.

^b The capital cost for oil and natural gas well sites includes the cost of implementing the monitoring program of \$32,120 divided by an average of 22 well sites per company.

^c Annual cost for oil and natural gas well sites and gathering and boosting stations includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7 percent interest.

^d Recovery credits for oil and natural gas well sites were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as \$4 Mcf.

(5) Notification of compliance status was estimated to take one person one hour to complete at a cost of \$58 for gathering and boosting stations. For companies that own and operate well sites, the cost of the notification of compliance was estimated to be \$58 per well site for each company-defined area, which is estimated to operate 22 well sites within the defined area for a total of \$1,272.

(6) Cost of a Method 21 monitoring device and data collection system was estimated at \$25,300 per company (\$10,800 for the M21 monitoring device and \$14,500 for the data collection system).

Costs for implementing a fugitive emission monitoring plan for a company-defined area for well sites and gathering and boosting stations were estimated for each of the monitoring and repair elements. The costs are based on the following assumptions:

- (1) Subsequent activities planning are estimated to take two people a total of 16 hours per monitoring event for well sites and two people a total of 24 hours for gathering and boosting stations. For well sites, this cost was divided among the total number of well sites in the company-defined area.
- (2) Method 21 monitoring was estimated to take two people a total of 16 hours to survey a well production site at a cost of \$925 per survey. For gathering and boosting stations, Method 21 monitoring was estimated to take 2 people a total of 8 hours to survey the station at a cost of \$925 per survey.
- (3) Annual repair costs for well sites were estimated to be \$299 using a repair threshold of 10,000 ppm and \$5,400 using a repair threshold of 500 ppm. These costs were estimated assuming that 1.18 percent of the components leak. The repair costs assume 75 percent are repaired online and 25 percent are repaired offline.
- (4) Annual repair costs for gathering and boosting stations were estimated to be \$3,436 using a repair threshold of 10,000 ppm and \$52,900 using a repair threshold of 500 ppm. These costs were estimated assuming that 1.18 percent of the components leak. The repair costs assume 75 percent are repaired online and 25 percent are repaired offline.
- (5) Cost for resurvey of components assumes 5 minutes per leak at \$57.80 per hour for well sites and \$2.00 per leak for gathering and boosting stations.
- (6) Preparation of annual reports was estimated to take 1 person a total of 4 hours to complete at a cost of \$231.

The initial setup cost or capital cost for oil and natural gas well sites was calculated by summing up the costs for reading the rule, development of fugitive emissions monitoring plan, initial activities planning, acquisition of a Method 21 monitoring device and data collection system and notification of initial compliance status. The total capital cost of these activities was estimated to be \$31,196 for annual monitoring, \$32,120 for semiannual monitoring, and \$33,970 for quarterly monitoring. Assuming that each company owns and operates 22 well sites within a company-defined area, the capital cost per well site was estimated to be \$1,460.

For gathering and boosting stations, the capital cost was assumed to be shared with other gathering and boosting stations within the company-defined area. These stations are estimated to be approximately 70 miles apart. Therefore, within a 210-mile radius of a central location, there would be an estimated seven gathering and boosting stations and the capital cost for these stations was estimated to be \$29,982 for annual monitoring, \$30,907 for semiannual monitoring, and \$32,756 for quarterly monitoring. Assuming that there are 7 gathering and boosting stations in a company-defined area, the capital cost per station was estimated to be \$4,283 for annual monitoring, \$4,415 for semiannual monitoring, and \$4,679 for quarterly monitoring.

For oil and natural gas well sites and gathering and boosting stations, the annual cost includes: subsequent activities planning, Method 21 survey, cost of repair of fugitive emissions found, preparation and submittal of an annual report, and the amortized capital cost over 8 years at 7 percent interest. The annual cost for annual, semiannual, and quarterly Method 21 surveying (inclusive of cost of repair of fugitive emissions found, preparation and submittal of an annual report, and amortized capital cost over 8 years at 7 percent interest) was calculated for each of the industry segments. Tables 9-14 through 9-16 present summaries of the cost of control for VOC at each of the repair thresholds (i.e., 10,000 and 500 ppm) for the three monitoring frequency options (i.e., annual, semiannual and quarterly).

9.3.2 Existing Federal, State and Local Regulations

9.3.2.1 *Federal Regulations that Specifically Require Control of VOC Emissions*

For each well site and compressor station (including gathering and boosting stations), the EPA has finalized NSPS requirements that will require the development of a fugitive emissions monitoring plan that includes semiannual monitoring for well sites and quarterly monitoring for

compressor stations by OGI and repair of leaking fugitive emission components. Method 21 can be used as an alternative to OGI at a 500 ppm repair threshold.

9.3.2.2 State and Local Regulations that Specifically Require Control of VOC Emissions

States or local air districts may have regulations or permitting restrictions on VOC emissions that may apply to an emission source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met, and often how the source must be operated. To ensure that sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements. A summary of some of the existing state regulations and permit programs that apply to the oil and natural gas industry is provided below.

Colorado Regulation 7

The State of Colorado has regulations that require leak inspections at all well sites, compressor stations upstream of the processing plant and storage vessels. For well production facilities and compressor stations, the monitoring frequency is determined by the estimated uncontrolled actual VOC emissions leak from the highest emitting tank or, if no tanks are present, the controlled actual emissions from all permanent equipment. The monitoring frequency for fugitives at well production facilities varies depending on emissions. There is a one-time inspection (0-6 tpy VOC), annual inspections (6-12 tpy VOC), quarterly inspections (12-20 tpy VOC w/o tanks, 12-50 w/ tanks), or monthly inspections (> 20 TPY VOC w/o tanks, > 50 tpy VOC w/ tanks). Monthly AVO inspections are also required for well production facilities that do one-time, annual, and quarterly monitoring. For compressor stations, the monitoring frequency is annual (0-12 tpy VOC), quarterly (12-50 tpy VOC), or monthly (> 50 tpy VOC). A leak is defined as hydrocarbon concentration greater than 500 ppm. These regulations allow OGI inspections, Method 21 or other “[d]ivision approved instrument based monitoring device or method” to detect leaks (Colorado Department of Public Health and Environment, Air Quality Control Commission, Regulation Number 7). The first attempt to repair leaks found during monitoring must be made no later than five working days after discovery, unless parts are unavailable or the equipment requires shutdown to complete repair. If

parts are unavailable, they must be ordered promptly and the repair must be made within 15 working days of receipt of the parts. If a shutdown is required, the leak must be repaired during the next scheduled shutdown.

Wyoming Chapter 8

The Wyoming Department of Environmental Quality issued regulations in June 2015 for existing (as of January 1, 2014) PAD facility (location where more than one well and/or associated production equipment are located, where some or all production equipment is shared by more than one well or where well streams from more than one well are routed through individual production trains at the same location) and single-well oil and gas production facilities or sources, and all compressor stations that are located in the Upper Green River Basin (UGRB) ozone nonattainment area¹⁵³. The rule requires operators with fugitive emissions greater than or equal to 4 tons per year of VOC to develop and implement an LDAR protocol by January 1, 2017. Operators must monitor components (flanges, connectors (other than flanges), open-ended lines, pumps, valves, and “other” components listed in Table 2-4 of the EPA’s Protocol for Equipment Leak Emissions Estimates) quarterly using a combination of Method 21, IR camera, other instrument based technologies, or AVO inspections. However, an LDAR protocol consisting of only AVO inspections does not meet the requirements of the rule. No specific repair timeframes are included in the regulation.

Utah General Approval Order

The Utah Department of Environmental Quality approved a “General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery” on June 5, 2014¹⁵⁴. This General Approval Order (GAO) requires LDAR for equipment (e.g., valve, flange or other connection, pump, compressor, pressure relief device or other vent, process drain, open-ended valve, pump seal, compressor seal, and access door seal or other seal that contains or contacts a process stream with hydrocarbons) based on annual throughput of crude oil and condensate. Annual inspections are required for sources that have a projected annual throughput of crude oil and condensate combined that is greater than or equal to 10,000 barrels or for sources that do not

¹⁵³ Wyoming regulations are available at <http://soswy.state.wy.us/Rules/RULES/9868.pdf>.

¹⁵⁴ Utah regulations are available at <http://www.deq.utah.gov/Permits/GAOs/docs/2014/6June/DAQE-AN149250001-14.pdf>.

have a crude oil or condensate storage tank onsite, and quarterly inspections are required for sources that have a projected annual throughput of crude oil and condensate combined that is greater than or equal to 25,000 barrels. For sources performing quarterly monitoring, provisions are provided for less frequent monitoring if no leaks are found during a year of monitoring. Repairs must be made within 15 days of finding a leak. A delay of repair is allowed if replacement parts are unavailable (must order parts within 5 days of detection and repair leak within 15 days after receipt of the parts) or technically infeasible to repair without a shutdown (shutdown must occur within 6 months of finding leak or operators must demonstrate emissions from shutdown would be greater than the uncontrolled leaking component).

The monitoring can be performed using Method 21, a tunable diode laser absorption spectroscopy (TDLAS) or an IR camera. A leak is defined as a reading of 500 ppm with Method 21 analyzer or TDLAS, or visible leak with IR camera.

Ohio General Permit

The Ohio EPA approved two types of general permits in May 2014 for oil and gas well site production operations (small flares and large flares) and high volume horizontal hydraulic fracturing for facilities that emit less than 1 ton per year of any toxic air contaminant (not including HAP emitting sources that are subject to MACT subpart HH)¹⁵⁵. Each permittee is required to develop and implement an LDAR program for ancillary equipment (pumps, compressors, pressure relief devices, connectors, valves, flanges, vents, covers, any bypass in a closed vent system, and each storage vessel) that requires monitoring using a forward looking infrared (FLIR) camera or Method 21. Leak definitions vary depending on component (most are 500 or 10,000 ppm). Quarterly monitoring is required for the first year and varies after that depending on performance. Repairs must be made within 30 days of finding a leak but if leaks cannot be repaired within that time frame, the general permit references the delay of repair provisions allowed under NSPS subpart VVa.

Ohio has also proposed a general permit for natural gas compressor stations that have the potential to leak greater than 10 tons per year of VOC. The general permit requirements for

¹⁵⁵ Ohio regulations available at
http://www.epa.ohio.gov/Portals/27/oil%20and%20gas/GP12.1_PTIOA20140403final.pdf
<http://epa.ohio.gov/dapc/genpermit/genpermits.aspx#127854016-available-permits>.

compressor stations are similar to the LDAR requirements for oil and gas well site production operations. No emissions data were available for this LDAR program.

Pennsylvania General Permit 5 and Exemption Category No. 38

General Permit 5 is a General Plan Approval and/or General Operating Permit for midstream natural gas gathering, compression and/or processing facilities that are minor air contamination facilities¹⁵⁶. Exemption Category No. 38 of the Air Quality Permit Exemption List applies to sources located at a well pad¹⁵⁷. The general permit requires operators to conduct leak detection and repair programs monthly using AVO methods. Equipment to be monitored include: valves, flanges, connectors, storage vessels/storage tanks, and compressor seals. In addition, the general permit requires annual monitoring at wells and quarterly monitoring for compression and processing facilities. Operators must use a FLIR camera or approved device to detect gaseous hydrocarbons leaks. All leaks at production sites, compressor stations or processing facilities must be repaired within 15 days of finding the leak.

West Virginia Class II General Permit G70-B

General Permit G70-B is for natural gas production facilities¹⁵⁸. The permit requires quarterly monitoring using AVO, Method 21 analyzers, IR cameras, or some combination. The AVO inspection shall include, but not be limited to, defects as visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. If a Method 21 analyzer is used, a leak (fugitive emissions of regulated air pollutants) is defined as no detectable emissions (less than 500 ppm). If an IR camera is used, no detectable emissions is defined as no visible leaks detected in accordance with U.S. EPA alternative IR camera work practices (40 CFR 60, subpart A). The first attempt at repair must be made within 5 calendar days of discovering the leak, and the final repair must be made within 15 calendar days of discovering the leak. No emissions data are available for this LDAR program.

¹⁵⁶ Pennsylvania regulations are available at http://www.dep.state.pa.us/dep/deputate/airwaste/aq/permits/gp/GP-5_2-25-2013.pdf.

¹⁵⁷ Pennsylvania regulations are available at <http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-96215/275-2101-003.pdf>.

¹⁵⁸ West Virginia regulations are available at <http://www.dep.wv.gov/daq/permitting/Documents/G70-B%20Final/G70-B%20General%20Permit%20Signed2.pdf>.

San Joaquin Valley Air Pollution Control District Rule 4409

The San Joaquin Valley Air Pollution Control District requires the development of an operator management plan that establishes inspection, replacement, re-inspection requirements, maintenance, repair periods and replacement retrofit requirements for components at light crude oil production facilities, natural gas production facilities and natural gas processing plants¹⁵⁹.

For manned facilities, the District requires owners and operators to audio-visually inspect for leaks daily and, for unmanned sites, the District requires owners and operators to audio-visually inspect for leaks weekly. Additionally, the District requires owners and operators to conduct inspections for leaks quarterly using Method 21. Leaks discovered are required to be repaired within two to seven days of discovery, depending on the magnitude of the leak. An extension of up to seven days is allowed if the leak is minor. Owners and operators are also allowed to apply for written approval to change the Method 21 monitoring inspection frequency from quarterly to annually if they meet specified criteria. Components at oil production facilities and gas production facilities that exclusively handle gas/vapor or liquid with a VOC content of 10 percent by weight or less are exempt from requirements.

9.4 Recommended RACT Level of Control

We evaluated available data obtained in the development of the 2016 NSPS final rule, comments received on the draft CTG and 2015 NSPS proposed rule, and peer review comments received on the EPA's equipment leaks white paper. Based on our evaluation of this data and information about existing regulations that control VOC emissions from oil and natural gas production sites, this CTG provides RACT recommendations for the collection of fugitive emission components at well sites with an average production of greater than 15 barrel equivalents per well per day, and gathering and boosting stations. At this time, this CTG does not include a RACT recommendation for well sites with an average production of less than 15 barrel equivalents per well per day. However, we encourage air agencies to consider site-specific data from these sources in their RACT analyses.

We further recommend that RACT be the implementation of a monitoring plan that includes semiannual monitoring for well sites with a GOR greater than or equal to 300 and quarterly monitoring for gathering and boosting stations using OGI or Method 21 and repair of

¹⁵⁹ San Joaquin Valley APCD regulations available at <http://www.arb.ca.gov/drdb/sju/cur.htm>.

components found to be leaking. The information currently available to EPA does not support applying the RACT recommendations related to fugitive monitoring contained in this chapter of the CTG to well sites with a GOR less than 300.

As discussed in section 9.3.2.2 of this chapter, some existing state and local regulations already require fugitive emissions monitoring of oil and natural gas production sites. The monitoring techniques listed in these requirements include the use of either Method 21 or OGI to locate fugitive emissions from equipment and components. In addition, peer review comments received on the equipment leaks white paper indicate that some companies are voluntarily monitoring their production sites using OGI to eliminate leaks from equipment. Monitoring and repair of equipment and components using OGI or Method 21 are the most viable methods for reducing fugitive emissions from equipment leaks in the production segment of the oil and natural gas industry.

Both Wyoming and Ohio require quarterly monitoring of components at production sites, and the cost of control per ton of VOC reduced is considered reasonable for OGI quarterly monitoring for natural gas well sites (about \$3,450 per ton of VOC reduced). However, based on the information currently available regarding the necessary equipment, trained personnel and the planning necessary to implement a monitoring and repair program, we are concerned about the potential compliance burden that could be associated with quarterly monitoring of the large number of existing well sites. The VOC cost of control for semiannual monitoring using OGI was estimated to be \$2,494 per ton of VOC reduced for natural gas well sites and \$5,062 per ton of VOC reduced for oil wells sites with a GOR greater than or equal to 300.

We do not estimate that there would be a compliance burden associated with quarterly fugitive OGI monitoring at gathering and boosting stations because there are fewer existing gathering and boosting stations than well sites. Moreover, the cost of control per ton of VOC reduced is reasonable for quarterly OGI monitoring. The VOC cost of control for quarterly monitoring using OGI was estimated to be about \$3,200 per ton of VOC reduced for gathering and boosting stations.

For well sites, the cost of control for a monitoring plan using Method 21 with a 10,000 ppm leak detection is generally more costly than the use of OGI where there are a large number of equipment components to be monitored. The cost for a natural gas well site was estimated to be \$4,667 per ton of VOC reduced for semiannual monitoring. The cost for an oil well site with a

GOR greater than 300 was estimated to be \$9,475 per ton of VOC reduced for semiannual monitoring. As shown in section 9.3.1 of this chapter, the cost of control for the 500 ppm repair threshold options are higher than the 10,000 ppm repair threshold option. The use of a monitoring plan using Method 21 with a 10,000 ppm leak detection may, however, be a lower cost alternative to OGI where there are fewer equipment components to be monitored. For gathering and boosting stations, the cost of control for a monitoring plan using Method 21 with a 10,000 ppm leak detection is estimated to be \$3,230 per ton of VOC reduced for semiannual monitoring and \$3,205 for quarterly monitoring. The costs for semiannual monitoring using Method 21 for natural gas well sites, and quarterly monitoring using Method 21 for gathering and boosting stations were considered reasonable (about \$4,670 for gas well sites and \$3,200 for gathering and boosting stations). Based on our analyses that indicates that a monitoring plan using Method 21 at 500 ppm would meet the same level of control as semiannual monitoring using OGI, we recommend that air agencies allow owners and operators to comply by using Method 21 at 500 ppm as an alternative to semiannual monitoring using OGI.

Based on existing state and local fugitive emission requirements, economic feasibility, and the reasonableness of costs, we recommend that RACT for the collection of fugitive emission components at well sites with a GOR greater than or equal to 300 that produce, on average, greater than 15 barrel equivalents per well per day, be the implementation of a fugitive emissions monitoring and repair plan that includes semiannual monitoring using OGI or Method 21. For these same reasons, we recommend that RACT for the collection of fugitive emission components at gathering and boosting stations be the implementation of a fugitive emissions monitoring and repair plan that includes quarterly monitoring using OGI or Method 21.

In summary, we recommend the following RACT for the collection of fugitive emission components at well sites and gathering and boosting stations in the production segment:

- (1) RACT for the Collection of Fugitive Emission Components at Well Sites With a GOR Greater than or Equal to 300, that Produce, on Average, Greater than 15 Barrel Equivalents per Well per Day: We recommend the implementation of a monitoring plan that includes semiannual monitoring using OGI and repair of components that are found to be leaking at well sites. We further recommend that air agencies allow Method 21 with a repair threshold of 500 ppm as an alternative compliance means to OGI. We also

recommend that each fugitive emissions component repaired or replaced be resurveyed to ensure there is no leak after repair or replacement by the use of either Method 21 or OGI no later than 30 days of finding fugitive emissions.

- (2) RACT for the Collection of Fugitive Emission Components at Gathering and Boosting Stations in the Production Segment (Located from the Wellhead to the Point of Custody Transfer to the Natural Gas Transmission and Storage Segment or Oil Pipeline): We recommend the implementation of a monitoring plan that includes quarterly monitoring using OGI and repair of components that are found to be leaking at gathering and boosting stations. We further recommend allowing Method 21 with a repair threshold of 500 ppm as an alternative to OGI. We also recommend that each fugitive emissions component repaired or replaced be resurveyed to ensure there is no leak after repair or replacement by the use of either Method 21 or OGI no later than 30 days of finding fugitive emissions.

9.5 Factors to Consider in Developing Fugitive Emissions RACT Procedures

To ensure that fugitive emissions are properly monitored and repaired (as necessary) under the RACT recommendations, we suggest that air agencies specify OGI/Method 21 monitoring and equipment repair recordkeeping and reporting requirements to document compliance. The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

9.5.1 Monitoring Recommendations

We recommend that air agencies require a fugitive emissions OGI/Method 21 monitoring plan that covers fugitive emission component sources that includes basic required monitoring plan elements. We recommend that air agencies require the monitoring plan be developed for a company-defined area and that it cover the collection of fugitive emissions components at well sites and gathering and boosting stations.

We suggest that the fugitive emissions monitoring plan that covers the collection of fugitive emissions components at well sites and gathering and boosting stations within each company-defined area include the following minimum elements:

- (1) Frequency for conducting surveys.
- (2) Technique for determining fugitive emissions.
- (3) Manufacturer and model number of fugitive emissions detection equipment to be used.
- (4) Procedures and timeframes for identifying and repairing fugitive emissions components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair.
- (5) Procedures and timeframes for verifying fugitive emission component repairs.
- (6) Records that will be kept and the length of time records will be kept.
- (7) If you are using OGI, you should also include the following: (i) Verification that your optical gas imaging equipment meets specification requirements (i.e., capable of imaging gases in a spectral range for the compound of highest concentration in the potential fugitive emissions, must be capable of imaging a gas that is half methane and half propane at a concentration of 10,000 ppm at a flow rate of less than or equal to 60 g/hr from a quarter inch diameter); (ii) Procedure for a daily verification check; (iii) Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained; (iv) Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold; (v) Procedures for conducting surveys; (vi) Training and experience needed prior to performing surveys; including how the operator will (a) ensure an adequate thermal background is present in order to view potential fugitive emissions, (b) deal with adverse monitoring conditions such as wind, (c) deal with interferences; and (vii) Procedures for calibration and maintenance.
- (8) Procedures for calibration and maintenance should comply with those recommended by the manufacturer of monitoring device used.
- (9) If you are using Method 21 of appendix A-7 of part 60, you should also include the following: (i) Verification that your monitoring equipment meets the requirements specified in section 6.0 of Method 21 at 40 CFR part 60, appendix A-7; and (ii) procedures for conducting surveys.

We suggest that you also require the following minimum elements in each fugitive emissions monitoring plan:

- (1) Sitemap.
- (2) A defined observation path that ensures that all fugitive emissions components are within sight of the path. The observation path must account for interferences.
- (3) If you are using Method 21, the plan should also include a list of fugitive emission components to be monitored and method for determining location of fugitive emission components to be monitored in the field (e.g., tagging, identification on a process and instrumentation diagram, etc.).
- (4) Your plan should also include the written plan developed for all of the fugitive emission components designated as difficult-to-monitor and unsafe-to-monitor.

We recommend a monitoring survey of each collection of fugitive emissions components at a well site be conducted semiannually after the initial survey and that consecutive semiannual monitoring surveys be conducted at least four months apart. We recommend a monitoring survey of each collection of fugitive emissions components at a gathering and boosting station be conducted quarterly after the initial survey and that consecutive quarterly monitoring surveys be conducted at least two months apart.

9.5.2 Repair Recommendations

We recommend that air agencies require that any identified source of fugitive emissions identified by using OGI (indicated by visual emissions) or Method 21 instrument (indicated by a concentration of 500 ppm above background) be repaired or replaced as soon as practicable, but no later than 30 calendar days after detection of the fugitive emissions. If the repair or replacement is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement must be completed during the next compressor station shutdown, well shutdown, well shut-in, after an unscheduled, planned or emergency vent blowdown or within 2 years, whichever is earlier. We also recommend that repaired or replaced fugitive emission components be required to be resurveyed as soon as practicable, but no later than 30 days after completion of the repair or replacement, to ensure that there is no leak. For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, we recommend that air agencies require that the operator resurvey the repaired fugitive emissions components using Method 21 (or alternative screening procedure based on soap bubble solution method (as specified under section 8.3.3 of Method 21)), or OGI no later than 30 days of being

repaired. A fugitive emissions component is repaired when either the Method 21 instrument indicates a concentration of less than 500 ppm above background, or an OGI instrument shows no indication of visible emissions.

Appendix

We include model rule language in this appendix for our recommended RACT for oil and natural gas industry sources. The intent of this language is to provide regulation language that states can use as a starting point in the development of their SIP. In some cases, the language may need to be revised to make it adequate for SIP approval purposes. Although we include model rule language for closed vent systems, control devices and performance tests (that apply across several model rule requirements for sources), it is acknowledged that states may have existing similar language in their programs that they may want to use in lieu of the model language provided. State implementation plans should specify enforceable test methods.

The model rule language does not specify rule compliance dates. These dates will be determined by air agencies (referred to within the model rule language as the “regulatory authority”). State and local government agencies are encouraged to search this model rule language for places where the “regulatory authority” will need to specify dates (e.g., compliance date) by searching for (“regulatory authority”) in the model rule language.

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A Storage Vessels: VOC Emission Control Requirements

A.1 Applicability

(a) The VOC emissions control requirements of section A apply to each storage vessel located in the oil and natural gas industry (excluding distribution) that has the potential for VOC emissions equal to or greater than 6 tpy. The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline established by your regulatory authority. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a federal, state, local or tribal authority. Any vapor from the storage vessel that is recovered and routed to a process through a VRU designed and operated as specified in this section is not required to be included in the determination of VOC potential to emit for purposes of determining applicability, provided you comply with the requirements in section A.1(a)(i) through (a)(iv).

(i) You meet the cover requirements specified in section A.2(c).

(ii) You meet the closed vent system requirements specified in section A.2(d).

(iii) You must maintain records that document compliance with paragraphs A.2(c) and (d).

(iv) In the event of removal of apparatus that recovers and routes vapor to a process, or operation that is inconsistent with the conditions specified in paragraphs A.2(c) and (d) of this section, you must determine the storage vessel's potential for VOC emissions according to this section within 30 days of such removal or operation.

(b) A storage vessel with a capacity greater than 100,000 gallons used to recycle water that has been passed through two stage separation is not a storage vessel.

(c) The storage vessel VOC emission control requirements specified in this section do not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb, 40 CFR part 63, subparts G, CC, HH, or WW.

A.2 What VOC Emission Control Requirements Apply to Storage Vessels?

For each storage vessel, you must comply with the VOC emission control requirements of paragraphs (a) through (e) in this section by the compliance date established by your regulatory authority. Alternative requirements for storage vessels subject to VOC emission control requirements that meet certain conditions are presented in paragraph (i) of this section. Requirements for storage vessels removed from service are presented in paragraph (j) of this section.

(a) You must reduce VOC emissions from each storage vessel by 95.0 percent, unless you meet the conditions of paragraph (i) of this section.

(b) (1) Except as required in paragraph (b)(2) of this section, if you use a control device to reduce emissions, you must equip the storage vessel with a cover that meets the requirements of paragraph (c) of this section, that is connected through a closed vent system that meets the requirements of paragraph (d) of this section and route to a control device that meets the conditions specified in paragraph (e) of this section, as applicable. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(2) If you use a floating roof to reduce emissions, you must meet the requirements of 40 CFR 60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb.

(c) *Cover requirements for storage vessels.* (1) The cover and all openings on the cover (*e.g.*, access hatches, sampling ports, pressure relief valves and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel.

(2) Each cover opening shall be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit;

(iii) To inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) To vent liquids, gases, or fumes from the unit through a closed vent system, designed and operated in accordance with the requirements of paragraph (d) of this section to a control device or to a process.

(3) Each storage vessel thief hatch shall be equipped, maintained and operated with a weight, or other mechanism, to ensure that the lid remains properly seated and sealed under normal operating conditions, including such times when working, standing/breathing, and flash emissions may be generated. You must select gasket material for the hatch based on composition of the fluid in the storage vessel and weather conditions.

(d) *Closed vent system requirements for storage vessels.* For closed vent system requirements using a control device or routing emissions to a process, you must comply with the following:

(1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the storage vessel to a control device or to a process that meets the requirements specified in paragraph (e) of this section, or to a process.

(2) You must design and operate a closed vent system with no detectable emissions, as determined using olfactory, visual and auditory inspections.

(3) You must meet the requirements specified in paragraph (d)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process.

(i) Except as provided in paragraph (d)(3)(ii) of this section, you must comply with either paragraph (d)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away for the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to section A.5(a)(9).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (d)(3)(i) of this section.

(4) You must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all emissions from the storage vessel are routed to the control device or to a process and that the control device is of sufficient design and capacity to accommodate all emissions from the storage vessel and have it certified by a qualified professional engineer in accordance with paragraphs (d)(4)(i) and (ii) of this section.

(i) You must provide the following certification, signed and dated by the qualified professional engineer: “I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted and this report was prepared pursuant to the requirements of this rule. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information.”

(ii) The assessment shall be prepared under the direction or supervision of the qualified professional engineer who signs the certification in paragraph (d)(4)(i) of this section.

(e) *Control device requirements for storage vessels.*

(1) Each control device used to meet the emission reduction standard in paragraph (a) of this section for your storage vessel must be installed according to paragraphs (e)(1)(i) through (iv) of this section, as applicable. As an alternative to paragraph (e)(1)(i) of this section, you may install a control device model tested under section F(d), which meets the criteria in section F(d)(11) and meets the continuous compliance requirements in section F(e).

(i) For each enclosed combustion device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) you must follow the requirements in paragraphs (e)(1)(i)(A) through (D) of this section.

(A) Ensure that each enclosed combustion device is maintained in a leak free condition.

(B) Install and operate a continuous burning pilot flame.

(C) Operate the enclosed combustion device with no visible emissions, except for periods not to exceed a total of one minute during any 15 minute period. A visible emissions test using section 11 of EPA Method 22, 40 CFR part 60, appendix A-7, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes. Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection. Following return to operation from maintenance or repair activity, each device must pass a Method 22, 40 CFR part 60, appendix A-7, visual observation as described in this paragraph.

(D) Each enclosed combustion control device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (1) through (4) of this section.

(1) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of section F(b).

(2) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the applicable requirements of section F(b).

(3) You must operate at a minimum temperature of 760°Celsius, provided the control device has demonstrated, during the performance test conducted under section F(b), that combustion zone temperature is an indicator of destruction efficiency.

(4) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(ii) Each vapor recovery device (*e.g.*, carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater. A carbon replacement schedule must be included in the design of the carbon adsorption system.

(iii) You must design and operate a flare in accordance with the requirements of 40 CFR 60.18(b), and you must conduct the compliance determination using Method 22, 40 CFR part 60, appendix A-7, to determine visible emissions.

(iv) You must operate each control device used to comply with paragraph (a) of this section at all times when gases, vapors, and fumes are vented from the storage vessel through the closed vent system to the control device. You may vent more than one storage vessel to a control device used to comply with this subpart.

(2) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (e)(2)(i) and (ii) of this section.

(i) Following the initial startup of the control device, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to section F(c)(2) or (3) or according to the design required in paragraph (e)(1)(ii) of this section, for the carbon adsorption system. You must maintain records identifying the schedule for replacement and records of each carbon replacement as required in section A.5(a)(10).

(ii) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (e)(2)(ii)(A) through (F) of this section.

(A) Regenerate or reactivate the spent carbon in a thermal treatment unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(B) Regenerate or reactivate the spent carbon in a unit equipped with operating organic air emission controls in accordance with an emissions standard for VOC under a subpart in 40 CFR part 60 or part 63.

(C) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(D) Burn the spent carbon in a hazardous waste boiler or industrial furnace for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(E) Burn the spent carbon in an industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(F) Burn the spent carbon in an industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

(f) You must demonstrate initial compliance with the VOC emission reduction requirements that apply to each storage vessel as required in section A.3.

(g) You must demonstrate continuous compliance with the VOC emission control requirements that apply to each storage vessel as required by section A.4.

(h) You must perform the required recordkeeping and reporting as required by section A.5.

(i) *Alternative requirements for storage vessels.* Maintain the uncontrolled actual VOC emissions from the storage vessel subject to VOC emission control requirements at less than 4 tpy without considering control. Prior to using the uncontrolled actual VOC emission rate for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual VOC emission rate each month. The uncontrolled actual VOC emissions must be calculated using a generally accepted model or calculation methodology. Monthly calculations must be based on the average throughput for the month. Monthly calculations must be separated by at least 14 days. You must comply with paragraph (i)(1) or (2) of this section.

(1) If a well feeding the storage vessel subject to VOC emission control requirements undergoes fracturing or refracturing, you must comply with paragraph (a) of this section as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel.

(2) If the monthly emissions determination required in this paragraph indicates that VOC emissions from your storage vessel subject to VOC emission control requirements increases to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel, you must comply with paragraph (a) of this section within 30 days of the monthly calculation.

(j) *Requirements for storage vessels that are removed from service or returned to service.* If you are the owner or operator of a storage vessel subject to the VOC emission control requirements that is removed from service, you must comply with paragraphs (j)(1) and (2) of

this section. A storage vessel is not an affected source under this section for the period that it is removed from service.

(1) For a storage vessel to be removed from service, you must comply with the requirements of paragraph (j)(1)(i) and (ii) of this section.

(i) You must completely empty and degas the storage vessel, such that the storage vessel no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty.

(ii) You must submit a notification in your next annual report, identifying each storage vessel removed from service during the reporting period and the date of its removal from service.

(2) If a storage vessel subject to VOC emission control requirements identified in paragraph (j)(1) of this section is returned to service during the reporting year, you must submit a notification in your next annual report identifying each storage vessel that has been returned to service and the date of its return to service.

A.3 Initial Compliance Demonstration Requirements

You must demonstrate initial compliance with the VOC emission control requirements for each storage vessel complying with section A.2 by complying with the requirements in paragraphs (a) through (h) of this section.

(a) You determine the potential VOC emission rate as specified in section A.1(a).

(b) You reduce VOC emissions from each storage vessel subject to VOC emission control requirements by 95.0 percent or greater as required in section A.2 and as demonstrated by section F.

(c) If you use a control device to reduce emissions, you must equip your storage vessel with a cover that meets the requirements of section A.2(c) that is connected through a closed vent system that meets the requirements of section A.2(d) and is routed to a control device that

meets the requirements of A.2(e). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(d) You conduct an initial performance test as required in section F within 180 days after the compliance date established by your regulatory authority.

(e) You conduct the initial cover and closed vent system inspections according to the requirements in section A.4(d) within 180 days after the compliance date established by your regulatory authority.

(f) You submit the initial annual report for your storage vessels as required in section A.5(b).

(g) You maintain the records as specified in section A.5(a).

(h) If you comply by using a floating roof, you submit a statement that you are complying with 40 CFR 60.112b(a)(1) or (2) in accordance with section A.2(b)(2) with the initial annual report specified in section A.5(b).

A.4 Continuous Compliance Demonstration Requirements

You have demonstrated continuous compliance for each storage vessel subject to the VOC emission control requirements in section A.2 by meeting the requirements in paragraphs (a) through (f) of this section.

(a) For each storage vessel subject to VOC emission reduction requirements, you must demonstrate continuous compliance according to paragraphs (b) and (c) of this section.

(b) You must reduce VOC emissions from the storage vessel by 95.0 percent or greater.

(c) For each control device used to reduce emissions, you must demonstrate continuous compliance with the performance requirements of section A.2(e) according to paragraphs (c)(1) through (4) of this section. You are exempt from the requirements of this paragraph if you install a control device model tested in accordance with sections F(d)(2) through (10), which meets the

criteria in section F(d)(11), the reporting requirements in section F(d)(12), and the continuous compliance requirements in F(e).

(1) For each combustion device you must conduct inspections at least once every calendar month according to paragraphs (c)(1)(i) through (iv) of this section. Monthly inspections must be separated by at least 14 calendar days.

(i) Conduct visual inspections to confirm that the pilot is lit when vapors are being routed to the combustion device and that the continuous burning pilot flame is operating properly.

(ii) Conduct inspections to monitor for visible emissions from the combustion device using section 11 of EPA Method 22, 40 CFR part 60, appendix A-7. The observation period shall be 15 minutes. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period.

(iii) Conduct olfactory, visual and auditory inspections of all equipment associated with the combustion device to ensure system integrity.

(iv) For any absence of pilot flame, or other indication of smoking or improper equipment operation (*e.g.*, visual, audible, or olfactory), you must ensure the equipment is returned to proper operation as soon as practicable after the event occurs. At a minimum, you must perform the procedures specified in paragraphs (c)(1)(iv)(A) and (B) of this section.

(A) You must check the air vent for obstruction. If an obstruction is observed, you must clear the obstruction as soon as practicable.

(B) You must check for liquid reaching the combustor.

(2) For each vapor recovery device, you must conduct inspections at least once every calendar month to ensure physical integrity of the control device according to the manufacturer's instructions. Monthly inspections must be separated by at least 14 calendar days.

(3) Each control device must be operated following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices

for minimizing emissions. Records of the manufacturer's written operating instructions, procedures, and maintenance schedule must be available for inspection as specified by A.5(a)(11).

(4) Conduct a periodic performance test no later than 60 months after the initial performance test as specified in section F(b)(5)(ii) and conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test.

(d) If you install a control device or route emissions to a process, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (d)(1) of this section, inspect each cover according to the procedures and schedule specified in paragraph (d)(2) of this section, and inspect each bypass device according to the procedures of paragraph (d)(3) of this section. You must also comply with the requirements of (d)(4) through (7) of this section.

(1) For each closed vent system, you must conduct an inspection at least once every calendar month as specified in paragraphs (d)(1)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in section A.5(a)(7).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(2) For each cover, you must conduct inspections at least once every calendar month as specified in paragraphs (d)(2)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in section A.5(a)(8).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or

gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (*e.g.*, fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(3) For each bypass device, except as provided for in section A.2(d)(3)(ii), you must meet the requirements of paragraphs (d)(3)(i) or (ii) of this section.

(i) You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible alarm, or initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is sounded according to section A.5(a)(9).

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections and records of each time the key is checked out, if applicable, according to section A.5(a)(9).

(4) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (d)(4)(i) through (iii) of this section, except as provided in paragraph (d)(5) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 30 calendar days after the leak is detected.

(iii) Grease or another applicable substance must be applied to deteriorating or cracked gaskets to improve the seal while awaiting repair.

(5) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(6) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (d)(6)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (d)(1) and (2) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (d)(1) or (2) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(7) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (d)(7)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (d)(1) and (2) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(e) You must submit the annual reports for your storage vessels as required in section A.5(b).

(f) You must maintain the records as specified in section A.5(a).

A.5 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements.* For each storage vessel, you must maintain the records identified in paragraphs (a)(1) through (12) of this section, as applicable, either onsite or at the nearest local field office for at least five years.

(1) If required to reduce emissions by complying with section A.2(a), the records specified in paragraphs (a)(6) through (8) of this section and sections A.4(d)(6)(ii) and A.4(d)(7)(ii), as applicable.

(2) Records of each VOC emissions determination for each storage vessel made under A.1(a) including identification of the model or calculation methodology used to calculate the VOC emission rate.

(3) Records of deviations in cases where the storage vessel was not operated in compliance with the requirements specified in sections A.2 and F, as applicable.

(4) For storage vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), records indicating the number of consecutive days that the vessel is located at a site in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment. If a storage vessel is removed from a site and, within 30 days, is either returned to or replaced by another storage vessel at the site to serve the same or similar function, then the entire period since the original storage vessel was first located at the site, including the days when the storage vessel was removed, must be added to the count towards the number of consecutive days.

(5) Records of the identification and location of each storage vessel subject to emission control requirements.

(6) Except as specified in paragraph (a)(6)(vii) of this section, you must maintain the records specified in paragraphs (a)(6)(i) through (vi) of this section for each control device tested under section F(d) which meets the criteria in section F(d)(11) and meets the continuous

compliance requirements in section F(d) (e) and used to comply with section A.2(a) for each storage vessel.

(i) Make, model and serial number of purchased device.

(ii) Date of purchase.

(iii) Copy of purchase order.

(iv) Location of the control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(v) Inlet gas flow rate.

(vi) Records of continuous compliance requirements in section F(e) as specified in paragraphs (a)(6)(vi)(A) through (E).

(A) Records that the pilot flame is present at all times of operation.

(B) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15 minute period.

(C) Records of the maintenance and repair log.

(D) Records of the visible emissions test following return to operation from a maintenance or repair activity.

(E) Records of the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(vii) As an alternative to the requirements of paragraph (a)(6)(iv) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the storage vessel and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital

photograph, the digital photograph may consist of a photograph of the storage vessel and control device with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(7) Records of each closed vent system inspection required under section A.4(d)(1)(i).

(8) A record of each cover inspection required under section A.4(d)(2)(i).

(9) If you are subject to the bypass requirements of section A.4(d)(3), a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

(10) For each carbon adsorber installed on a storage vessel, records of the schedule for carbon replacement (as determined by the design analysis requirements of section E.1(a)(2)) and records of each carbon replacement as specified in section E.1(c)(1).

(11) For each storage vessel subject to the control device requirements of section E.2(c) and (d), records of the inspections, including any corrective actions taken, the manufacturers' operating instructions, procedures and maintenance schedule as specified in section E.2(h). Records of section 11, EPA Method 22, 40 CFR part 60, appendix A-7 results, which include: company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use Figure 22-1 in EPA Method 22, 40 CFR part 60, appendix A-7. Control device manufacturer operating instructions, procedures and maintenance schedule must be available for inspection.

(12) A log of records as specified in sections A.2(e)(1)(i)(C) and F(e)(4), for all inspection, repair and maintenance activities for each control device failing the visible emissions test.

(b) *Reporting requirements.* For storage vessels, you must submit annual reports containing the information specified in paragraphs (b)(1) through (6) of this section.

(1) An identification, including the location, of each storage vessel subject to VOC emission control requirements. The location of the storage vessel shall be in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(2) Documentation of the VOC emission rate determination according to section A.1(a).

(3) Records of deviations specified in paragraph (a)(3) of this section that occurred during the reporting period.

(4) A statement that you have met the requirements specified in section A.3(b) and (c).

(5) You must identify each storage vessel that is removed from service during the reporting period as specified in section A.2(j)(1), including the date the storage vessel was removed from service.

(6) You must identify each storage vessel returned to service during the reporting period as specified in section A.2(j)(3), including the date the storage vessel was returned to service.

A.6 Definitions

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding \$25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including, but not limited to, general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.*, a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions. Completion combustion devices include pit flares.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Hydraulic fracturing means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

Hydraulic refracturing means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

Maximum average daily throughput means the earliest calculation of daily average throughput during the 30-day PTE evaluation period employing generally accepted methods.

Natural gas liquids means the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Natural gas transmission means the pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a

production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

Pressure vessel means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

Produced water means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

Qualified professional engineer means an individual who is licensed by a state as a Professional Engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge and experience to make the specific technical certifications required under this subpart. Professional engineers making these certifications must be currently licensed in at least one state in which the certifying official is located.

Removed from service means that a storage vessel subject to the VOC control requirements has been physically isolated and disconnected from the process for a purpose other than maintenance.

Returned to service means that a storage vessel subject to the VOC requirements that was removed from service has been:

(1) Reconnected to the original source of liquids or has been used to replace any storage vessel subject to the VOC requirements; or

(2) Installed in any location covered by this rule and introduced with crude oil, condensate, intermediate hydrocarbon liquids or produced water.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process that is operational where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered for beneficial use.

Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of section A.2(j)(1) until such time as such tank or other vessel has been returned to service. For the purposes of this rule, the following are not considered storage vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by section A.5(a)(4), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site.

(2) Process vessels such as surge control vessels, bottoms receivers or knockout vessels.

(3) Pressure vessels designed to operate in excess of 204.9 kilopascals (29.7 pounds per square inch) and without emissions to the atmosphere.

B Pneumatic Controllers: VOC Emission Control Requirements

B.1 Applicability

The VOC emission control requirements specified in section B.2 apply to the pneumatic controllers specified in paragraphs (a) and (b) of this section.

(a) For natural gas processing plants, each pneumatic controller, which is a single continuous bleed natural gas-driven pneumatic controller.

(b) At locations from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline, each pneumatic controller, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 standard cubic feet per hour.

B.2 What VOC Emission Control Requirements Apply to Pneumatic Controllers?

For each pneumatic controller, you must comply with requirements for VOC, as specified in either paragraph (b)(1) or (c)(1) of this section, as applicable. Pneumatic controllers meeting the conditions in paragraph (a) of this section are exempt from these requirements.

(a) The requirements of paragraph (b)(1) or (c)(1) of this section are not required if you determine that the use of a pneumatic controller with a bleed rate greater than the applicable standard is required based on functional needs including, but not limited to, response time, safety and positive actuation. However, you must tag such pneumatic controller with the date that the pneumatic controller is required to comply with the model rule (as established by your regulatory authority) and identification information that allows traceability to the records for that pneumatic controller, as required in section B.5(a)(2).

(b)(1) Each pneumatic controller subject to VOC emissions control requirements at a natural gas processing plant must have a bleed rate of zero.

(2) Each pneumatic controller subject to VOC emissions control requirements at a natural gas processing plant, as defined in section B.1(a), must be tagged with the date that the pneumatic controller is required to comply with the model rule (as established by your regulatory authority) and identification information that allows traceability to the records for that pneumatic controller as required in section B.5(a)(3).

(c)(1) Each pneumatic controller subject to VOC emissions control requirements at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline must have a bleed rate less than or equal to 6 standard cubic feet per hour.

(2) Each pneumatic controller subject to VOC emission control requirements at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline, as defined in section B.1(b), must be tagged with the date that the pneumatic controller is required to comply with the model rule (as established by your regulatory authority) that allows traceability to the records for that controller as required in section B.5(a).

(d) You must demonstrate initial compliance by the compliance date established by your regulatory authority by demonstrating compliance with the VOC emission reduction requirements that apply to pneumatic controllers as required by section B.3.

(e) You must demonstrate continuous compliance with VOC emission reduction requirements that apply to pneumatic controllers as required by section B.4.

(f) You must perform the required recordkeeping as required by B.5(a) and reporting as required by section B.5(b).

B.3 Initial Compliance Demonstration Requirements

You must demonstrate initial compliance with the VOC emission control requirements for your pneumatic controller by complying with the requirements specified in paragraphs (a) through (f) of this section by the compliance date established by your regulatory authority, as applicable.

(a) You must demonstrate initial compliance by maintaining records as specified in section B.5(a)(2) of your determination that the use of a pneumatic controller with a bleed rate greater than the applicable standard is required as specified in section B.2(a).

(b) You own or operate a pneumatic controller located at a natural gas processing plant and your pneumatic controller is a non-natural gas-driven pneumatic controller that emits zero natural gas and VOC.

(c) You own or operate a pneumatic controller located between the wellhead and a natural gas processing plant and the manufacturer's design specifications indicate that the controller emits less than or equal to 6 standard cubic feet of gas per hour.

(d) You must tag each pneumatic controller according to the requirements of section B.2(b)(2) or (c)(2).

(e) You must include the information in paragraph (a) of this section and a listing of the pneumatic controller sources specified in paragraphs (b) and (c) of this section in the initial annual report according to the requirements of section B.5(b)

(f) You must maintain the records as specified in section B.5(a) for each pneumatic controller subject to VOC emission control requirements.

B.4 Continuous Compliance Demonstration Requirements

For each pneumatic controller, you must demonstrate continuous compliance according to paragraphs (a) through (c) of this section.

(a) You must continuously operate each pneumatic controller as required in section B.2(a), (b), or (c).

(b) You must submit the annual reports as required in section B.5(b).

(c) You must maintain records as required in section B.5(a).

B.5 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements.* For each pneumatic controller, you must maintain the records identified in paragraphs (a)(1) through (4) of this section onsite or at the nearest local field office for at least five years.

(1) Records of the date, location and manufacturer specifications for each pneumatic controller.

(2) If applicable, a record of the demonstration that the use of a pneumatic controller with a natural gas bleed rate greater than the applicable standard is required and the reasons why.

(3) If the pneumatic controller is located at a natural gas processing plant, records of the documentation that the natural gas bleed rate is zero.

(4) Records of deviations in cases where the pneumatic controller was not operated in compliance with the requirements specified in section B.2.

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (3) of this section.

(1) An identification of each existing pneumatic controller, including the identification information specified in section B.2(b)(2) or (c)(2).

(2) If applicable, documentation that the use of a pneumatic controller with a natural gas bleed rate greater than the applicable standard is required and the reasons why.

(3) Records of deviations specified in paragraph (a)(4) of this section that occurred during the reporting period.

B.6 Definitions

Bleed rate means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a pneumatic controller.

Continuous bleed means a continuous flow of pneumatic supply natural gas to a pneumatic controller.

Custody transfer means the transfer of natural gas after processing and/or treatment in the producing operations or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Flow line means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.

Natural gas-driven pneumatic controller means a pneumatic controller powered by pressurized natural gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

Non-natural gas-driven pneumatic controller means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Pressure vessel means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

Underground storage vessel means a storage vessel stored below ground

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

C Compressors: VOC Emissions Control Requirements

C.1 Applicability

(a) *Centrifugal compressors.* Each centrifugal compressor, which is a single centrifugal compressor using wet seals located between the wellhead and point of custody transfer to the natural gas transmission and storage segment. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not a source subject to VOC requirements under this rule.

(b) *Reciprocating compressors.* Each reciprocating compressor located between the wellhead and point of custody transfer to the natural gas transmission and storage segment. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not a source subject to VOC requirements under this rule.

C.2 What VOC Emission Control Requirements Apply to Centrifugal Compressors?

For each centrifugal compressor, you must comply with the VOC emissions control requirements in paragraphs (a) through (g).

(a) You must reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent.

(b) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of section D.1(a)(1). The cover must be connected through a closed vent system that meets the requirements of section D.1(b) and the closed vent system must be routed to a control device that meets the conditions specified in paragraph (d) of this section. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(c) For each control device used to comply with the VOC emission reduction control requirements in paragraph (a), you must install and operate a continuous parameter monitoring

system for each control device as specified in section E.2(a) through (f), except as provided for in section E.2(b).

(d) You must operate each control device installed on your centrifugal compressor in accordance with the requirements specified in paragraphs (d)(1) and (2) of this section.

(1) You must operate each control device used to comply with this rule at all times when gases, vapors, and fumes are vented from the wet seal fluid degassing system through the closed vent system to the control device. You may vent more than one source to a single control device.

(2) For each control device monitored in accordance with the requirements of section E.2(a) through (f), you must demonstrate continuous compliance according to the requirements of section C.5(a)(2), as applicable.

(e) You must demonstrate initial compliance with the VOC emission reduction requirements that apply to each centrifugal compressor as required by section C.4(a).

(f) You must demonstrate continuous compliance with the VOC emission control requirements that apply to each centrifugal compressor as required by section C.5(a).

(g) You must perform the required recordkeeping and reporting as required by section C.6(a)(1) and (b)(1), as applicable.

C.3 What VOC Emission Control Requirements Apply to Reciprocating Compressors?

You must comply with the VOC emission control requirements in paragraphs (a) through (d) of this section for each reciprocating compressor.

(a) You must replace the reciprocating compressor rod packing according to either paragraph (a)(1) or (2) of this section or you must comply with paragraph (a)(3) of this section.

(1) On or before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning on the compliance date for your

reciprocating compressor as established by your regulatory authority, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the compliance date for a reciprocating compressor for which the rod packing has not yet been replaced.

(3) Route VOC emissions to a process by using a rod packing emissions collection system that operates under negative pressure and meets the cover requirements of section D.1(a)(2) and the closed vent system requirements of section D.1.(b).

(b) You must demonstrate initial compliance with requirements that apply to reciprocating compressor sources as required by section C.4(b).

(c) You must demonstrate continuous compliance with requirements that apply to reciprocating compressor sources as required by section C.5(b).

(d) You must perform the required recordkeeping and reporting as required by section C.6(a)(2) and (b)(2).

C.4 Initial Compliance Demonstration Requirements

You must demonstrate initial compliance with the VOC emission control requirements for each centrifugal compressor by complying with the requirements in paragraph (a) of this section, and for each reciprocating compressor by complying with the requirements in paragraph (b) of this section.

(a) *Centrifugal compressors.* You have achieved initial compliance with the VOC emission control requirements for each centrifugal compressor if you have complied with paragraphs (a)(1) through (7) of this section.

(1) You reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater as required in section C.2(a) and as demonstrated by section F.

(2) You use a control device to reduce emissions, and you equip the wet seal fluid degassing system with a cover that meets the requirements of section D.1(a) that is connected through a closed vent system that meets the requirements of section D.1(b) and is routed to a control device that meets the requirements of section E.1. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(3) You conduct an initial performance test as required in section F within 180 days after the compliance date established by your regulatory authority.

(4) You conduct the initial cover and closed vent system inspections required in section D.2 within 180 days after the compliance date established by your regulatory authority.

(5) You install and operate the continuous parameter monitoring systems in accordance with section E.2(a) through (g).

(6) You submit the initial annual report for your centrifugal compressor as required in section C.6(b)(1).

(7) You maintain the records as specified in section C.6(a)(1).

(b) *Reciprocating compressors.* You have achieved initial compliance with the VOC emission control requirements for each reciprocating compressor if you have complied with paragraphs (b)(1) through (4) of this section.

(1) If complying with section C.3(a)(1) and (2), you must continuously monitor the number of hours of operation or track the number of months since the last rod packing replacement, beginning on the compliance date established by your regulatory authority.

(2) If complying with section C.3(a)(3), you must route VOC emissions to a process by using a rod packing emissions collection system that operates under negative pressure and meets the cover requirements of section D.1(a)(2) and the closed vent system requirements of section D.1(b) by the compliance date established by your regulatory authority.

(3) You must submit the initial annual report for your reciprocating compressor as required in section C.6(b)(2).

(4) You maintain the records as specified in section C.6(a)(2).

C.5 Continuous Compliance Demonstration Requirements

You have demonstrated continuous compliance for each centrifugal compressor by complying with the requirements of paragraph (a), and for each reciprocating compressor by complying with the requirements of paragraph (b).

(a) *Centrifugal compressors.* For each centrifugal compressor subject to VOC emission reduction requirements, you must demonstrate continuous compliance according to paragraphs (a)(1) through (4) of this section.

(1) You must reduce VOC emissions from the wet seal fluid degassing system by 95.0 percent or greater.

(2) For each control device used to reduce emissions, you must demonstrate continuous compliance with the performance requirements of section C.2(a) using the procedures specified in paragraphs (a)(2)(i) through (vii) of this section. If you use a condenser as the control device to achieve the requirements specified in section C.2(a), you may demonstrate compliance according to paragraph (a)(2)(viii) of this section. You may switch between compliance with paragraphs (a)(2)(i) through (vii) of this section and compliance with paragraph (a)(2)(viii) of this section only after at least 1 year of operation in compliance with the selected approach. You must provide notification of such a change in the compliance method in the next annual report, following the change.

(i) You must operate below (or above) the site specific maximum (or minimum) parameter value established according to the requirements of section E.2(f)(1).

(ii) You must calculate the daily average of the applicable monitored parameter in accordance with section E.2(e) except that the inlet gas flow rate to the control device must not be averaged.

(iii) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (a)(2)(ii) of this section is either equal to or greater than the minimum monitoring value or equal to or less than the maximum monitoring value established under paragraph (a)(2)(i) of this section. When performance testing of a combustion control device is conducted by the device manufacturer as specified in section F(d), compliance with the operating parameter limit is achieved when the criteria in section F(e) are met.

(iv) You must operate the continuous monitoring system required in section E.2(a) at all times the source is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments). A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(v) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other required data collection periods to assess the operation of the control device and associated control system.

(vi) Failure to collect required data is a deviation of the monitoring requirements, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments).

(vii) If you use a combustion control device to meet the requirements of section C.2(a) and you demonstrate compliance using the test procedures specified in section F(b), or you use a flare designed and operated in accordance with 40 CFR 60.18(b), you must comply with paragraphs (a)(2)(vii)(A) through (D) of this section.

(A) A pilot flame must be present at all times of operation.

(B) Devices must be operated with no visible emissions, except for periods not to exceed a total of one minute during any 15-minute period. A visible emissions test using section 11 of Method 22, 40 CFR part 60, appendix A-7, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(C) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(D) Following return to operation from maintenance or repair activity, each device must pass a Method 22, 40 CFR part 60, appendix A-7, visual observation as described in paragraph (a)(2)(vii)(B) of this section.

(viii) If you use a condenser as the control device to achieve the percent reduction performance requirements specified in section C.2(a)(1), you must demonstrate compliance using the procedures in paragraphs (a)(2)(viii)(A) through (E) of this section.

(A) You must establish a site-specific condenser performance curve according to section E.2(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with section E.2(e).

(C) You must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (a)(2)(viii)(B) of this section and the condenser performance curve established under paragraph (a)(2)(viii)(A) of this section.

(D) You must calculate the 365-day rolling average TOC emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (a)(2)(viii)(C) of this section.

(1) If you have less than 120 days of data for determining average TOC emission reduction, you must calculate the average TOC emission reduction for the first 120 days of operation. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the 120-day average TOC emission reduction is equal to or greater than 95.0 percent.

(2) After 120 days and no more than 364 days of operation, you must calculate the average TOC emission reduction as the TOC emission reduction averaged over the number of days of operation where you have data. You have demonstrated compliance with the overall 95.0 percent reduction requirement, if the average TOC emission reduction is equal to or greater than 95.0 percent.

(E) If you have data for 365 days or more of operation, you have demonstrated compliance with the TOC emission reduction if the rolling 365-day average TOC emission reduction calculated in paragraph (a)(2)(viii)(D) of this section is equal to or greater than 95.0 percent.

(3) You must submit the annual reports required by section C.6(b)(1) and maintain the records as specified in section C.6(a)(1).

(4) If you comply with this rule by equipping the wet seal fluid degassing system and route emissions to a control device or process as required by section C.2(b), you must comply with the cover and closed vent requirements in section D.1(a) and (b).

(b) *Reciprocating compressors.* For each reciprocating compressor subject to VOC emission reduction requirements, you must demonstrate continuous compliance according to paragraphs (b)(1) through (4) of this section.

(1) You must continuously monitor the number of hours of operation for each reciprocating compressor or track the number of months or the date of the most recent reciprocating compressor rod packing replacement.

(2) You must submit the annual reports as required in section C.6(b)(2) and maintain records as required in section C.6(a)(2).

(3) You must replace the reciprocating compressor rod packing on or before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months.

(4) If you comply with this rule by collecting and routing VOC emissions from the rod packing using a rod packing emissions collection system which operates under negative pressure as required by section C.3(a)(3), you must operate the rod packing emissions collection system under negative pressure and continuously comply with the closed vent system requirements in section D.1(b).

C.6 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements.*

(1) *Centrifugal compressors.* For each centrifugal compressor, you must maintain records of the information specified in paragraphs (a)(1)(i) and (ii) of this section, and, if required to comply with section C.2(a), the records specified in paragraphs (a)(1)(iii) through (ix) of this section. These records must be maintained onsite or at the nearest local field office for at least five years.

(i) An identification of each existing centrifugal compressor using a wet seal system.

(ii) Records of deviations where the centrifugal compressor was not operated in compliance with requirements specified in section C.2. Except as specified in paragraph (a)(1)(ii)(G) of this section, you must maintain the records in paragraphs (a)(1)(ii)(A) through (F) of this section for each control device tested under section F(d) which meets the criteria in section F(d)(11) and meets continuous compliance requirements in section F(e) and used to comply with section C.2(a) for each centrifugal compressor.

(A) Make, model and serial number of purchased device.

(B) Date of purchase.

(C) Copy of purchase order.

(D) Location of the centrifugal compressor and control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(E) Inlet gas flow rate.

(F) Records of continuous compliance requirements in section F(e) as specified in paragraphs (a)(1)(ii)(F)(1) through (5) of this section.

(1) Records that the pilot flame is present at all times of operation.

(2) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15 minute period.

(3) Records of the maintenance and repair log.

(4) Records of the visible emissions test following return to operation from a maintenance or repair activity.

(5) Records of the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(G) As an alternative to the requirements of paragraph (a)(1)(ii)(D) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the centrifugal compressor and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the centrifugal compressor and control device with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(iii) Records of each closed vent system inspection required under section D.2(a) and (b).

(iv) A record of each cover inspection required under section D.2(c).

(v) If you are subject to the bypass requirements of section D.2(d), a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

(vi) If you are subject to the closed vent system no detectable emissions requirements of section D.2(a) and (b), a record of the monitoring in accordance with section D.2(e).

(vii) For each centrifugal compressor, records of the schedule for carbon replacement (as determined by the design analysis requirements of section F(c)(2) or (3)) and records of each carbon replacement as specified in section E.1(c)(1).

(viii) For each centrifugal compressor subject to the control device requirements of section E.1, records of minimum and maximum operating parameter values, continuous parameter monitoring system data, calculated averages of continuous parameter monitoring system data, results of all compliance calculations, and results of all inspections.

(ix) A log of records for all inspection, repair and maintenance activities for each control device failing the visible emissions test as specified in section C.5(a)(2)(vii)(C).

(2) *Reciprocating compressors.* For each reciprocating compressor VOC emissions source, you must maintain the records in paragraphs (a)(2)(i) through (iv) of this section. These records must be maintained onsite or at the nearest local field office for at least five years.

(i) Records of the cumulative number of hours of operation or number of months since the previous replacement of the reciprocating compressor rod packing. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

(ii) Records of the date and time of each reciprocating compressor rod packing replacement, or date of installation of a rod packing emissions collection system and closed vent system as specified in section C.3(a)(3).

(iii) Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in section C.3.

(iv) If you comply by routing emissions from the rod packing to a process through a closed vent system under negative pressure. You must maintain the records in paragraphs (a)(2)(iv)(A) through (D) of this section.

(A) Records of each closed vent system inspection required under section D.2(a) and (b).

(B) If you are subject to the bypass requirements of section D.2(d), a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

(C) If you are subject to the closed vent system no detectable emissions requirements of section D.2(a) and (b), a record of the monitoring in accordance with section D.2(e).

(D) A record of each cover inspection required under section D.2(c).

(b) *Reporting requirements.*

(1) *Centrifugal compressors.* For each centrifugal compressor, you must submit annual reports containing the information specified in paragraphs (b)(1)(i) through (iv) of this section.

(i) An identification of each existing centrifugal compressor using a wet seal system.

(ii) Records of deviations specified in paragraph (a)(1)(ii) of this section that occurred during the reporting period.

(iii) If required to comply with section C.2(a), the records specified in paragraphs (a)(1)(iii) through (viii) of this section.

(iv) If complying with C.2(a) with a control device tested under section F(d) which meets the criteria in section F(d)(11) and meets the continuous compliance requirements in section F(e), in the initial annual report, records specified in paragraphs (a)(1)(ii)(A) through (a)(1)(ii)(G) of this section for each centrifugal compressor using a wet seal system that is subject to this rule. In subsequent annual reports, records specified in paragraph (a)(1)(ii)(F) of this section along with information sufficient to link to the identifying information provided in the initial report.

(2) *Reciprocating compressors.* For each reciprocating compressor, you must submit annual reports containing the information specified in paragraphs (b)(2)(i) through (iii) of this section.

(i) The cumulative number of hours of operation or the number of months since the compliance date, or since the previous reciprocating compressor rod packing replacement, whichever is later. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

(ii) Records of deviations specified in paragraph (a)(2)(iii) of this section that occurred during the reporting period.

(iii) If required to comply with section C.3(a)(3), the records specified in paragraphs (a)(2)(i) through (iv) of this section.

C.7 Definitions

Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low-pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this rule.

Collection system means any infrastructure that conveys gas or liquids from the well site to another location for treatment, storage, processing, recycling, disposal or other handling.

Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations. The combination of one or more compressors located at a well site, or located at an onshore natural gas processing plant, is not a compressor station for purposes of this rule.

Custody transfer means the transfer of natural gas after processing and/or treatment in the producing operations or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Flow line means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere, or other mechanism that provides the same function.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well.

D Cover and Closed Vent System Requirements

[Note: These requirements would not apply to covers and closed vent systems used on storage vessels.]

D.1 What Are My Cover and Closed Vent System Requirements?

You must meet the applicable requirements of this section for each cover and closed vent system where VOC emissions are routed to a control device or to a process.

(a) *Cover requirements.*

(1) Centrifugal compressor cover requirements.

(i) The cover and all openings on the cover shall form a continuous impermeable barrier over the entire surface area of the liquid in the wet seal fluid degassing system.

(ii) Each cover opening shall be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) except during those times when it is necessary to use an opening as follows:

(A) To inspect, maintain, repair, or replace equipment; or

(B) To vent gases or fumes from the unit through a closed vent system designed and operated in accordance with the requirements of paragraph (b) of this section to a control device or to a process.

(2) Reciprocating compressor cover requirements.

(i) The cover and all openings on the cover shall form a continuous impermeable barrier over the rod packing emissions collection system.

(ii) Each cover opening shall be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) except during those times when it is necessary to use an opening as follows:

(A) To inspect, maintain, repair, or replace equipment; or

(B) To vent gases or fumes from the unit through a closed vent system designed and operated in accordance with the requirements of paragraph (b) of this section to a process.

(b) *Closed vent system requirements.*

(1) (i) Centrifugal compressors. You must design the closed vent system to route all gases, vapors, and fumes emitted from the VOC emissions source to a control device or to a process. For centrifugal compressors, the closed vent system must route all gases, vapors, and fumes to a control device that meets the requirements specified in section E.1(a) through (c).

(ii) Reciprocating compressors. You must design the closed vent system to route all gases, vapors, and fumes emitted from the VOC emissions source to a process.

(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by section D.2(e).

(3) You must meet the requirements specified in paragraph (b)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or process.

(i) Except as provided in paragraph (b)(3)(ii) of this section, you must comply with either paragraph (b)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings as specified in section D.2(d)(1) and sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away for the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to section C.6(a)(1)(v) for centrifugal compressors, C.6(a)(2)(iv)(B) for reciprocating compressors or H.5(a)(2)(ii) for pneumatic pumps, as applicable.

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (b)(3)(i) of this section.

(4) You must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all emissions from the emission source are routed to the control device and that the control device is of sufficient design and capacity to accommodate all emissions from the emission source and have it certified by a qualified professional engineer in accordance with paragraphs (b)(4)(i) and (ii) of this section.

(i) You must provide the following certification, signed and dated by the qualified professional engineer: “I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted and this report was prepared pursuant to the requirements of this rule. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information.”

(ii) The assessment shall be prepared under the direction or supervision of the qualified professional engineer who signs the certification in paragraph (b)(4)(i) of this section.

D.2 What Are My Initial and Continuous Cover and Closed Vent System Inspection and Monitoring Requirements?

Except as provided in paragraphs (e)(11) and (12) of this section, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a) and (b) of this section, inspect each cover according to the procedures and schedule specified in paragraph (c) of this section, and inspect each bypass device according to the procedures of paragraph (d) of this section.

(a) For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (*e.g.*, a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), you must meet the requirements specified in paragraphs (a)(1) and (2) of this section.

(1) Conduct an initial inspection according to the test methods and procedures specified in paragraph (e) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results according to section C.6(a)(1)(vi) for centrifugal compressors, C.6(a)(2)(iv)(C) for reciprocating compressors or H.5(a)(2)(iii) for pneumatic pumps, as applicable.

(2) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must monitor a component or connection using the test methods and procedures in paragraph (e) of this section to demonstrate that it operates with no detectable emissions following any time the component is repaired or the connection is unsealed. You must maintain records of the inspection results according to section C.6(a)(1)(vi) for centrifugal compressors, C.6(a)(2)(iv)(C) for reciprocating compressors or H.5(a)(2)(iii) for pneumatic pumps, as applicable.

(b) For closed vent system components other than those specified in paragraph (a) of this section, you must meet the requirements of paragraphs (b)(1) through (3) of this section.

(1) Conduct an initial inspection according to the test methods and procedures specified in paragraph (e) of this section to demonstrate that the closed vent system operates with no detectable emissions by the date established by your regulatory authority. You must maintain records of the inspection results according to section C.6(a)(1)(vi) for centrifugal compressors, C.6(a)(2)(iv)(C) for reciprocating compressors or H.5(a)(2)(iii) for pneumatic pumps, as applicable.

(2) Conduct annual inspections according to the test methods and procedures specified in paragraph (e) of this section to demonstrate that the components or connections operate with no detectable emissions. You must maintain records of the inspection results according to section C.6(a)(1)(vi) for centrifugal compressors, C.6(a)(2)(iv)(C) for reciprocating compressors or H.5(a)(2)(iii) for pneumatic pumps, as applicable.

(3) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose

connections; liquid leaks; or broken or missing caps or other closure devices. You must maintain records of the inspection results according to section C.6(a)(1)(vi) for centrifugal compressors, or H.5(a)(2)(i) for pneumatic pumps, as applicable.

(c) For each cover, you must meet the requirements in paragraphs (c)(1) and (2) of this section.

(1) Conduct visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices.

(2) You must initially conduct the inspections specified in paragraph (c)(1) of this section following the installation of the cover. Thereafter, you must perform the inspection at least once every calendar year, except as provided in paragraphs (e)(11) and (12) of this section. For centrifugal compressors, you must maintain records of the inspection results according to section C.6(a)(1)(iv). For reciprocating compressors, you must maintain records of the inspection results according to C.6(a)(2)(iv)(D).

(d) For each bypass device, except as provided for in section D.1(b)(3)(ii), you must meet the requirements of paragraphs (d)(1) or (2) of this section.

(1) Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the stream away from the control device to the atmosphere.

(2) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections according to section C.6(a)(1)(v) for centrifugal compressors, C.6(a)(2)(iv)(B) for reciprocating compressors or H.5(a)(2)(ii) for pneumatic pumps, as applicable.

(e) *No detectable emissions test methods and procedures.* If you are required to conduct an inspection of a closed vent system or cover as specified in paragraphs (a), (b), or (c) of this section, you must meet the requirements of paragraphs (e)(1) through (13) of this section.

(1) You must conduct the no detectable emissions test procedure in accordance with Method 21, 40 CFR part 60, appendix A-7.

(2) The detection instrument must meet the performance criteria of Method 21, 40 CFR part 60, appendix A-7, except that the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the fluid and not for each individual organic compound in the stream.

(3) You must calibrate the detection instrument before use on each day of its use by the procedures specified in EPA Method 21, 40 CFR part 60, appendix A-7.

(4) Calibration gases must be as specified in paragraphs (e)(4)(i) and (ii) of this section.

(i) Zero air (less than 10 parts per million by volume hydrocarbon in air).

(ii) A mixture of methane in air at a concentration less than 10,000 parts per million by volume.

(5) You may choose to adjust or not adjust the detection instrument readings to account for the background organic concentration level. If you choose to adjust the instrument readings for the background level, you must determine the background level value according to the procedures in EPA Method 21, 40 CFR part 60, appendix A-7.

(6) Your detection instrument must meet the performance criteria specified in paragraphs (e)(6)(i) and (ii) of this section.

(i) Except as provided in paragraph (e)(6)(ii) of this section, the detection instrument must meet the performance criteria of EPA Method 21, 40 CFR part 60, appendix A-7, except the instrument response factor criteria in section 8.1.1 of EPA Method 21 must be for the average composition of the process fluid, not each individual volatile organic compound in the stream.

For process streams that contain nitrogen, air, or other inerts that are not volatile organic compounds, you must calculate the average stream response factor on an inert-free basis.

(ii) If no instrument is available that will meet the performance criteria specified in paragraph (e)(6)(i) of this section, you may adjust the instrument readings by multiplying by the average response factor of the process fluid, calculated on an inert-free basis, as described in paragraph (e)(6)(i) of this section.

(7) You must determine if a potential leak interface operates with no detectable emissions using the applicable procedure specified in paragraph (e)(7)(i) or (ii) of this section.

(i) If you choose not to adjust the detection instrument readings for the background organic concentration level, then you must directly compare the maximum organic concentration value measured by the detection instrument to the applicable value for the potential leak interface as specified in paragraph (e)(8) of this section.

(ii) If you choose to adjust the detection instrument readings for the background organic concentration level, you must compare the value of the arithmetic difference between the maximum organic concentration value measured by the instrument and the background organic concentration value as determined in paragraph (e)(5) of this section with the applicable value for the potential leak interface as specified in paragraph (e)(8) of this section.

(8) A potential leak interface is determined to operate with no detectable organic emissions if the organic concentration value determined in paragraph (e)(7) of this section is less than 500 parts per million by volume.

(9) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (e)(9)(i) and (ii) of this section, except as provided in paragraph (e)(10) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 15 calendar days after the leak is detected.

(10) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(11) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (e)(11)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (a) through (c) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (a), (b), or (c) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(12) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (e)(12)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (a) through (c) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(13) *Records.* Records shall be maintained as specified in this section and in sections that reference this section.

E VOC Emission Control Device Requirements

[These requirements do not apply to control devices used on storage vessels.]

E.1 Initial Control Device Compliance Requirements

You must meet the applicable requirements of this section for each control device used to comply with VOC emission reduction requirements.

(a) Each control device used to meet the VOC emission reduction requirements must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative, you may install a control device model tested under section F(d), which meets the criteria in section F(d)(11) and the continuous compliance requirements in section F(e).

(1) Each combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (iv) of this section.

(i) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of section F(b), with the exceptions noted in section F(a).

(ii) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the applicable requirements of section F(b), with the exceptions noted in section F(a).

(iii) You must operate at a minimum temperature of 760° Celsius for a control device, provided the control device has demonstrated, during the performance test conducted under section F(b), that combustion zone temperature is an indicator of destruction efficiency.

(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(2) Each vapor recovery device (e.g., carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of section F(b). As an alternative to the performance testing requirements, you may demonstrate initial compliance by conducting a design analysis for vapor recovery devices according to the requirements of section F(c).

(3) You must design and operate a flare in accordance with the requirements of 40 CFR 60.18(b), and you must conduct the compliance determination using EPA Method 22 of 40 CFR part 60, appendix A-7, to determine visible emissions.

(b) You must operate each control device installed to control VOC emissions from your emissions source in accordance with the requirements specified in paragraphs (b)(1) and (2) of this section.

(1) You must operate each control device used to comply with this rule at all times when gases, vapors, and fumes are vented from your VOC emissions source through the closed vent system to the control device. You may vent more than one source to a control device used to comply with this rule.

(2) For each control device monitored in accordance with the requirements of section E.2(a) through (g), you must demonstrate continuous compliance according to the requirements of section C.5(a)(2) for centrifugal compressors, as applicable.

(c) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a)(2) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (c)(1) and (2) of this section.

(1) Following the compliance date established by your regulatory authority for the source using the control device, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to section F(c)(2) or (3) or according to the design required in paragraph (a)(2) of this

section, for the carbon adsorption system. You must maintain records identifying the schedule for replacement and records of each carbon replacement.

(2) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (c)(2)(i) through (vi) of this section.

(i) Regenerate or reactivate the spent carbon in a thermal treatment unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(ii) Regenerate or reactivate the spent carbon in a unit equipped with operating organic air emission controls in accordance with an emissions standard for VOC under a subpart in 40 CFR part 60 or part 63.

(iii) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(iv) Burn the spent carbon in a hazardous waste boiler or industrial furnace for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(v) Burn the spent carbon in an industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(vi) Burn the spent carbon in an industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

E.2 Continuous Control Device Monitoring Requirements

You must meet the applicable requirements of this section to demonstrate continuous compliance for each control device used to meet VOC emission control requirements.

(a) For each control device used to comply with the VOC emission reduction requirements, you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with section E.1(a)(3), you are exempt from the requirements of paragraphs (e) and (f) of this section.

(b) You are exempt from the monitoring requirements specified in paragraphs (c) through (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.

(1) A boiler or process heater in which all vent streams are introduced with the primary fuel, or used as the primary fuel.

(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(c) If you are required to install a continuous parameter monitoring system, you must meet the specifications and requirements in paragraphs (c)(1) through (4) of this section.

(1) Each continuous parameter monitoring system must measure data values at least once every hour and record the parameters in paragraphs (c)(1)(i) or (ii) of this section.

(i) Each measured data value.

(ii) Each block average value for each 1-hour period or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(2) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (c)(2)(i) through (v) of this section. You must install, calibrate, operate, and maintain each continuous parameter monitoring system in accordance with the procedures in your approved site-specific monitoring plan. Heat sensing monitoring devices that indicate the

continuous ignition of a pilot flame are exempt from the calibration, quality assurance and quality control requirements in this section.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(ii) Sampling interface (e.g., thermocouple) location such that the monitoring system will provide representative measurements.

(iii) Equipment performance checks, system accuracy audits, or other audit procedures.

(iv) Ongoing operation and maintenance procedures in accordance with provisions in 40 CFR 60.13(b).

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in 40 CFR 60.7(c), (d), and (f).

(3) You must conduct the continuous parameter monitoring system equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(4) You must conduct a performance evaluation of each continuous parameter monitoring system in accordance with the site-specific monitoring plan. Heat sensing monitoring devices that indicate the continuous ignition of a pilot flame are exempt from the calibration, quality assurance and quality control requirements in this section.

(d) You must install, calibrate, operate, and maintain a device equipped with a continuous recorder to measure the values of operating parameters appropriate for the control device as specified in either paragraph (d)(1), (2), or (3) of this section.

(1) A continuous monitoring system that measures the operating parameters in paragraphs (d)(1)(i) through (viii) of this section, as applicable.

(i) For a thermal vapor incinerator that demonstrates during the performance test conducted under section F(b) that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ± 1 percent of the temperature being monitored in $^{\circ}\text{Celsius}$, or $\pm 2.5^{\circ}\text{Celsius}$, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(ii) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device must be capable of monitoring temperature at two locations and have a minimum accuracy of ± 1 percent of the temperature being monitored in $^{\circ}\text{Celsius}$, or $\pm 2.5^{\circ}\text{Celsius}$, whichever value is greater. You must install one temperature sensor in the vent stream at the nearest feasible point to the catalyst bed inlet, and you must install a second temperature sensor in the vent stream at the nearest feasible point to the catalyst bed outlet.

(iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame. The heat sensing monitoring device is exempt from the calibration requirements of this section.

(iv) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ± 1 percent of the temperature being monitored in $^{\circ}\text{Celsius}$, or $\pm 2.5^{\circ}\text{Celsius}$, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(v) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ± 1 percent of the temperature being monitored in $^{\circ}\text{Celsius}$, or $\pm 2.5^{\circ}\text{Celsius}$, whichever value is greater. You must install the temperature sensor at a location in the exhaust vent stream from the condenser.

(vi) For a regenerative-type carbon adsorption system, a continuous monitoring system that meets the specifications in paragraphs (d)(1)(vi)(A) and (B) of this section.

(A) The continuous parameter monitoring system must measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow continuous parameter monitoring system is not equipped with a redundant flow sensor; and

(B) The continuous parameter monitoring system must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device must have a minimum accuracy of ± 1 percent of the temperature being monitored in $^{\circ}\text{Celsius}$, or $\pm 2.5^{\circ}\text{Celsius}$, whichever value is greater.

(vii) For a non-regenerative-type carbon adsorption system, you must monitor the design carbon replacement interval established using a design analysis performed as specified in section F(c)(3). The design carbon replacement interval must be based on the total carbon working capacity of the control device and source operating schedule.

(viii) For a combustion control device whose model is tested under section F(d), a continuous monitoring system meeting the requirements of paragraphs (d)(1)(viii)(A) and (B) of this section. If you comply with the periodic testing requirements of F(b)(5)(ii), you are not required to continuously monitor the gas flow rate under paragraph (d)(1)(viii)(A).

(A) The continuous monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ± 2 percent or better at the maximum expected flow rate. The flow rate at the inlet to the combustion device must not exceed the maximum or minimum flow rate determined by the manufacturer.

(B) A monitoring device that continuously indicates the presence of the pilot flame while emissions are routed to the control device.

(2) An organic monitoring device equipped with a continuous recorder that measures the concentration level of organic compounds in the exhaust vent stream from the control device. The monitor must meet the requirements of Performance Specification 8 or 9 of 40 CFR part 60, appendix B. You must install, calibrate, and maintain the monitor according to the manufacturer's specifications.

(e) You must calculate the daily average value for each monitored operating parameter for each operating day, using the data recorded by the monitoring system, except for inlet gas flow rate and data from the heat sensing devices that indicate the presence of a pilot flame. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(f) For each operating parameter monitor installed in accordance with the requirements of paragraph (d) of this section, you must comply with paragraph (f)(1) of this section for all control devices. When condensers are installed, you must also comply with paragraph (f)(2) of this section.

(1) You must establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of section E.1(a)(1) or (2). You must establish each minimum or maximum operating parameter value as specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) If you conduct performance tests in accordance with the requirements of section F(b) to demonstrate that the control device achieves the applicable performance requirements specified in section E.1(a)(1) or (2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer recommendations or a combination of both.

(ii) If you use a condenser design analysis in accordance with the requirements of section F(c) to demonstrate that the control device achieves the applicable performance requirements specified in section E.1(a)(2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on the condenser design analysis and supplemented, as necessary, by the condenser manufacturer's recommendations.

(iii) If you operate a control device where the performance test requirement was met under section F(d) to demonstrate that the control device achieves the applicable performance requirements specified in section E.1(a)(1), then your control device inlet gas flow rate must not exceed the maximum or minimum inlet gas flow rate determined by the manufacturer.

(2) If you use a condenser as specified in paragraph (d)(1)(v) of this section, you must establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency, according to the requirements of paragraphs (f)(2)(i) and (ii) of this section.

(i) If you conduct a performance test in accordance with the requirements of section F(b) to demonstrate that the condenser achieves the applicable performance requirements in section E.1(a)(2), then the condenser performance curve must be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(ii) If you use a control device design analysis in accordance with the requirements of section F(c)(1) to demonstrate that the condenser achieves the applicable performance requirements specified in section E.1(a)(2), then the condenser performance curve must be based on the condenser design analysis and supplemented, as necessary, by the control device manufacturer's recommendations.

(g) A deviation for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (g)(1) through (6) of this section being met. If you monitor multiple operating parameters for the same control device during the same operating day and more than one of these operating parameters meets a deviation criterion specified in paragraphs (g)(1) through (6) of this

section, then a single excursion is determined to have occurred for the control device for that operating day.

(1) A deviation occurs when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section or when the heat sensing device indicates that there is no pilot flame present.

(2) If you meet section E.1(a)(2), a deviation occurs when the 365-day average condenser efficiency calculated according to the requirements specified in section C.5(a)(2)(viii)(D) is less than 95.0 percent.

(3) If you meet section E.1(a)(2) and you have less than 365 days of data, a deviation occurs when the average condenser efficiency calculated according to the procedures specified in section C.5(a)(2)(viii)(D)(1) or (2) is less than 95.0 percent.

(4) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

(5) If the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, a deviation occurs when the requirements of paragraphs (g)(5)(i) or (ii) of this section are met.

(i) For each bypass line subject to section D.1(b)(3)(i)(A), the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

(ii) For each bypass line subject to section D.1(b)(3)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

(6) For a combustion control device whose model is tested under section F(d), a deviation occurs when the conditions of paragraphs (g)(6)(i) or (ii) are met.

(i) The inlet gas flow rate exceeds the maximum established during the test conducted under section F(d).

(ii) Failure of the monthly visible emissions test conducted under section F(e)(3) occurs.

F Performance Test Procedures

This section applies to the performance testing of control devices used to demonstrate compliance with your VOC emission control requirements. You must demonstrate that a control device achieves the performance requirements specified for your centrifugal compressor using the performance test methods and procedures specified in this section. For condensers and carbon adsorbers, you may use a design analysis as specified in paragraph (c) of this section in lieu of complying with paragraph (b) of this section. In addition, this section contains the requirements for enclosed combustion device performance tests conducted by the manufacturer, as relevant and allowed for compliance demonstration purposes.

(a) *Performance test exemptions.* You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (7) of this section.

(1) *A flare that is designed and operated in accordance with 40 CFR 60.18(b).* You must conduct the compliance determination using EPA Method 22, 40 CFR part 60, appendix A-7, to determine visible emissions.

(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.

(4) A boiler or process heater burning hazardous waste for which you have either been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, subpart H; you have certified compliance with the interim status requirements of 40 CFR part 266, subpart H; you have submitted a Notification of Compliance under 40 CFR 63.1207(j) and comply with the requirements of 40 CFR part 63, subpart EEE; or you comply with 40 CFR part 63, subpart EEE and will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in the rule for submitting the initial performance test report.

(5) A hazardous waste incinerator for which you have submitted a Notification of Compliance under 40 CFR 63.1207(j), or for which you will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in the rule for submitting the initial performance test report, and you comply with the requirements of 40 CFR part 63, subpart EEE.

(6) A performance test is waived in accordance with 40 CFR 60.8(b).

(7) A control device whose model can be demonstrated to meet the performance requirements of section E.1(a) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

(b) *Test methods and procedures.* You must use the test methods and procedures specified in paragraphs (b)(1) through (5) of this section, as applicable, for each performance test conducted to demonstrate that a control device meets the requirements of section E.1(a) or A.2(e)(1). You must conduct the initial and periodic performance tests according to the schedule specified in paragraph (b)(5) of this section. Each performance test must consist of a minimum of 3 test runs. Each run must be at least 1 hour long.

(1) You must use EPA Method 1 or 1A, 40 CFR part 60, appendix A-1, as appropriate, to select the sampling sites specified in paragraphs (b)(1)(i) and (ii) of this section. Any references to particulate mentioned in EPA Methods 1 and 1A do not apply to this section.

(i) Sampling sites must be located at the inlet of the first control device and at the outlet of the final control device, to determine compliance with the control device percent reduction requirement.

(ii) The sampling site must be located at the outlet of the combustion device to determine compliance with the enclosed combustion device TOC exhaust gas concentration limit.

(2) You must determine the gas volumetric flowrate using EPA Method 2, 2A, 2C, or 2D, 40 CFR part 60, appendix A-2, as appropriate.

(3) To determine compliance with the control device percent reduction performance requirement in section E.1(a)(1)(i) or (a)(2), or section A.2(e)(1)(i)(D)(1) or (e)(1)(ii), you must

use EPA Method 25A at 40 CFR part 60, appendix A-7. You must use EPA Method 4 at 40 CFR part 60, appendix A-3 to convert the EPA Method 25A results to a dry basis. You must use the procedures in paragraphs (b)(3)(i) through (iii) of this section to calculate percent reduction efficiency.

(i) You must compute the mass rate of TOC using the following equations:

$$E_i = K_2 C_i M_p Q_i$$

$$E_o = K_2 C_o M_p Q_o$$

Where:

E_i , E_o = Mass rate of TOC at the inlet and outlet of the control device, respectively, dry basis, kilograms per hour.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20°Celsius.

C_i , C_o = Concentration of TOC, as propane, of the gas stream as measured by EPA Method 25A at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

M_p = Molecular weight of propane, 44.1 gram/gram-mole.

Q_i , Q_o = Flowrate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

(ii) You must calculate the percent reduction in TOC as follows:

$$R_{cd} = \frac{E_i - E_o}{E_i} * 100\%$$

Where:

R_{cd} = Control efficiency of control device, percent.

E_i = Mass rate of TOC at the inlet to the control device as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

E_o = Mass rate of TOC at the outlet of the control device, as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

(iii) If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC across the device by comparing the TOC in all combusted vent streams and primary and secondary fuels with the TOC exiting the device, respectively.

(4) You must use EPA Method 25A, 40 CFR part 60, appendix A-7 to measure TOC, as propane, to determine compliance with the TOC exhaust gas concentration limit specified in section E.1(a)(1)(ii) or section A.2(e)(1)(i)(D)(2). You may also use EPA Method 18, 40 CFR part 60, appendix A-6 to measure methane and ethane. You may subtract the measured concentration of methane and ethane from the EPA Method 25A measurement to demonstrate compliance with the concentration limit. You must determine the concentration in parts per million by volume on a wet basis and correct it to 3 percent oxygen, using the procedures in paragraphs (b)(4)(i) through (iii) of this section.

(i) If you use EPA Method 18 to determine methane and ethane, you must take either an integrated sample or a minimum of four grab samples per hour. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15-minute intervals during the run. You must determine the average methane and ethane concentration per run. The samples must be taken during the same time as the EPA Method 25A sample.

(ii) You may subtract the concentration of methane and ethane from the EPA Method 25A TOC, as propane, concentration for each run.

(iii) You must correct the TOC concentration (minus methane and ethane, if applicable) to 3 percent oxygen as specified in paragraphs (b)(4)(iii)(A) and (B) of this section.

(A) You must use the emission rate correction factor for excess air, integrated sampling and analysis procedures of EPA Method 3A or 3B, 40 CFR 60, appendix A-2, ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17) to determine the oxygen concentration. The samples must be taken during the same time that the samples are taken for determining TOC concentration.

(B) You must correct the TOC concentration for percent oxygen as follows:

$$C_c = C_m \left(\frac{17.9}{20.9 - \%O_{2m}} \right)$$

Where:

C_c = TOC concentration, as propane, corrected to 3 percent oxygen, parts per million by volume on a wet basis.

C_m = TOC concentration, as propane, (minus methane and ethane, if applicable), parts per million by volume on a wet basis.

$\%O_{2m}$ = Concentration of oxygen, percent by volume as measured, wet.

(5) You must conduct performance tests according to the schedule specified in paragraphs (b)(5)(i) and (ii) of this section.

(i) You must conduct an initial performance test within 180 days after the compliance date for your source as established by your regulatory authority.

(ii) You must conduct periodic performance tests for all control devices required to conduct initial performance tests except as specified in paragraphs (b)(5)(ii)(A) and (B) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(5)(i) of this section. You must conduct

subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit.

(A) A control device whose model is tested under, and meets the criteria of paragraph (d) of this section. For centrifugal compressors, if you do not continuously monitor the gas flow rate in accordance with section E.2(d)(1)(viii), then you must comply with the periodic performance testing requirements of paragraph (b)(5)(ii).

(B) A combustion control device tested under paragraph (b) of this section that meets the outlet TOC performance level specified in section E.1(a)(1)(ii) and that establishes a correlation between firebox or combustion chamber temperature and the TOC performance level. For centrifugal compressors, you must establish a limit on temperature in accordance with section E.2(f) and continuously monitor the temperature as required by section E.2(d).

(c) *Control device design analysis to meet the requirements of section E.1(a).* (1) For a condenser, the design analysis must include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and must establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream and the design average temperatures of the coolant fluid at the condenser inlet and outlet.

(2) For a regenerable carbon adsorption system, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, adsorption cycle time, number and capacity of carbon beds, type and working capacity of activated carbon used for the carbon beds, design total regeneration stream flow over the period of each complete carbon bed regeneration cycle, design carbon bed temperature after regeneration, design carbon bed regeneration time, and design service life of the carbon.

(3) For a nonregenerable carbon adsorption system, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, capacity of the carbon bed, type and working capacity of activated carbon

used for the carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule. In addition, these systems will incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(4) If you and the regulatory authority do not agree on a demonstration of control device performance using a design analysis, then you must perform a performance test in accordance with the requirements of paragraph (b) of this section to resolve the disagreement. The regulatory authority may choose to have an authorized representative observe the performance test.

(d) Performance testing for combustion control devices—manufacturers' performance test. (1) This paragraph applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer must demonstrate that a specific model of control device achieves the performance requirements in paragraph (d)(11) of this section by conducting a performance test as specified in paragraphs (d)(2) through (10) of this section. You must submit a test report for each combustion control device in accordance with the requirements in paragraph (d)(12) of this section.

(2) Performance testing must consist of three one-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. Propene (propylene) gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90-100 percent of maximum design rate (fixed rate).

(ii) 70-100-70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30-70-30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 70 percent

of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0-30-0 percent (ramp up, ramp down). Begin the test at the minimum firing rate. During the first 5 minutes, incrementally ramp the firing rate to 30 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to the minimum firing rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures must be tested simultaneously and with all burners operational. Results must be reported for each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data must be collected continuously throughout the performance test using an electronic Data Acquisition System. A graphic presentation or strip chart of the control device operating data and emissions test data must be included in the test report in accordance with paragraph (d)(12) of this section. Inlet fuel meter data may be manually recorded provided that all inlet fuel data readings are included in the final report.

(4) Inlet testing must be conducted as specified in paragraphs (d)(4)(i) and (ii) of this section.

(i) The inlet gas flow metering system must be located in accordance with EPA Method 2A, 40 CFR part 60, appendix A-1 (or other approved procedure) to measure inlet gas flow rate at the control device inlet location. You must position the fitting for filling fuel sample containers a minimum of eight pipe diameters upstream of any inlet gas flow monitoring meter.

(ii) Inlet flow rate must be determined using EPA Method 2A, 40 CFR part 60, appendix A-1. Record the start and stop reading for each 60-minute THC test. Record the gas pressure and temperature at 5-minute intervals throughout each 60-minute test.

(5) Inlet gas sampling must be conducted as specified in paragraphs (d)(5)(i) and (ii) of this section.

(i) At the inlet gas sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 3-hour period. Filling must be conducted as specified in paragraphs (d)(5)(i)(A) through (C) of this section.

(A) Open the canister sampling valve at the beginning of each test run, and close the canister at the end of each test run.

(B) Fill one canister across the three test runs such that one composite fuel sample exists for each test condition.

(C) Label the canisters individually and record sample information on a chain of custody form.

(ii) Analyze each inlet gas sample using the methods in paragraphs (d)(5)(ii)(A) through (C) of this section. You must include the results in the test report required by paragraph (d)(12) of this section.

(A) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945-03.

(B) Hydrogen (H₂), carbon monoxide (CO), carbon dioxide (CO₂), nitrogen (N₂), oxygen (O₂) using ASTM D1945-03.

(C) Higher heating value using ASTM D3588-98 or ASTM D4891-89.

(6) Outlet testing must be conducted in accordance with the criteria in paragraphs (d)(6)(i) through (v) of this section.

(i) Sample and flow rate must be measured in accordance with paragraphs (d)(6)(i)(A) and (B) of this section.

(A) The outlet sampling location must be a minimum of four equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one

equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports must be used.

(B) Flow rate must be measured using EPA Method 1, 40 CFR part 60, appendix A-1 for determining flow measurement traverse point location, and EPA Method 2, 40 CFR part 60, appendix A-1 for measuring duct velocity. If low flow conditions are encountered (*i.e.*, velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer must be used to obtain an accurate flow profile.

(ii) Molecular weight and excess air must be determined as specified in paragraph (d)(7) of this section.

(iii) Carbon monoxide must be determined as specified in paragraph (d)(8) of this section.

(iv) THC must be determined as specified in paragraph (d)(9) of this section.

(v) Visible emissions must be determined as specified in paragraph (d)(10) of this section.

(7) Molecular weight and excess air determination must be performed as specified in paragraphs (d)(7)(i) through (iii) of this section.

(i) An integrated bag sample must be collected during the moisture test required by EPA Method 4, 40 CFR part 60, appendix A-3 following the procedure specified in paragraphs (d)(7)(i)(A) and (B) of this section. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC-TCD) analysis meeting the criteria in paragraphs (d)(7)(i)(C) and (D) of this section.

(A) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(B) Purge the sampling line with stack gas before opening the valve and beginning to fill the bag. Clearly label each bag and record sample information on a chain of custody form.

(C) The bag contents must be vigorously mixed prior to the gas chromatograph analysis.

(D) The GC-TCD calibration procedure in EPA Method 3C, 40 CFR part 60, appendix A-2, must be modified by using EPA Alt-045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, repeat the initial calibration using at least three concentration levels.

(ii) Calculate and report the molecular weight of oxygen, carbon dioxide, methane, and nitrogen in the integrated bag sample and include in the test report specified in paragraph (d)(12) of this section. Moisture must be determined using EPA Method 4, 40 CFR part 60, appendix A-3. Traverse both ports with the EPA Method 4, 40 CFR part 60, appendix A-3, sampling train during each test run. Ambient air must not be introduced into the integrated bag sample required by EPA Method 3C, 40 CFR part 60, appendix A-2, sample during the port change.

(iii) Excess air must be determined using resultant data from the EPA Method 3C tests and EPA Method 3B, 40 CFR part 60, appendix A-2, equation 3B-1, or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only).

(8) Carbon monoxide must be determined using EPA Method 10, 40 CFR part 60, appendix A-4. Run the test simultaneously with EPA Method 25A, 40 CFR part 60, appendix A-7 using the same sampling points. An instrument range of 0-10 parts per million by volume-dry (ppmvd) is recommended.

(9) Total hydrocarbon determination must be performed as specified in paragraphs (d)(9)(i) through (vii) of this section.

(i) Conduct THC sampling using EPA Method 25A, 40 CFR part 60, appendix A-7, except that the option for locating the probe in the center 10 percent of the stack is not allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during each test run.

(ii) A valid test must consist of three EPA Method 25A, 40 CFR part 60, appendix A-7, tests, each no less than 60 minutes in duration.

(iii) A 0-10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0-30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases must be propane in air and be certified through EPA Protocol 1—“EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards”.

(v) THC measurements must be reported in terms of ppmvw as propane.

(vi) THC results must be corrected to 3 percent CO₂, as measured by EPA Method 3C, 40 CFR part 60, appendix A-2. You must use the following equation for this diluent concentration correction:

$$C_{corr} = C_{meas} \left(\frac{3}{CO_{2meas}} \right)$$

Where:

C_{meas} = The measured concentration of the pollutant.

CO_{2meas} = The measured concentration of the CO₂ diluent.

3 = The corrected reference concentration of CO₂ diluent.

C_{corr} = The corrected concentration of the pollutant.

(vii) Subtraction of methane or ethane from the THC data is not allowed in determining results.

(10) Visible emissions must be determined using EPA Method 22, 40 CFR part 60, appendix A-7. The test must be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date

and time, must be taken once per test run and the 12 photos included in the test report specified in paragraph (d)(12) of this section.

(11) *Performance test criteria.* (i) The control device model tested must meet the criteria in paragraphs (d)(11)(i)(A) through (D) of this section. These criteria must be reported in the test report required by paragraph (d)(12) of this section.

(A) Results from EPA Method 22, 40 CFR part 60, appendix A-7, results under paragraph (d)(10) of this section with no indication of visible emissions.

(B) Average EPA Method 25A, 40 CFR part 60, appendix A-7, results under paragraph (d)(9) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO₂.

(C) Average CO emissions determined under paragraph (d)(8) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO₂.

(D) Excess combustion air determined under paragraph (d)(7) of this section equal to or greater than 150 percent.

(ii) The manufacturer must determine a maximum inlet gas flow rate which must not be exceeded for each control device model to achieve the criteria in paragraph (d)(11)(iii) of this section. The maximum inlet gas flow rate must be included in the test report required by paragraph (d)(12) of this section.

(iii) A manufacturer must demonstrate a destruction efficiency of at least 95.0 percent for THC, as propane. A control device model that demonstrates a destruction efficiency of 95.0 percent for THC, as propane, will meet the control requirement for 95.0 percent destruction of VOC required under this rule.

(12) The owner or operator of a combustion control device model tested under this paragraph must submit the information listed in paragraphs (d)(12)(i) through (vi) in the test report. Owners or operators who claim that any of the performance test information being submitted is confidential business information (CBI) must submit a complete file including

information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to Attn: CBI Officer; OAQPS CBIO Room 521; 109 T.W. Alexander Drive; RTP, NC 27711. The same file with the CBI omitted must be submitted to Oil_and_Gas_PT@EPA.GOV.

- (i) A full schematic of the control device and dimensions of the device components.
- (ii) The maximum net heating value of the device.
- (iii) The test fuel gas flow range (in both mass and volume). Include the maximum allowable inlet gas flow rate.
- (iv) The air/stream injection/assist ranges, if used.
- (v) The test conditions listed in paragraphs (d)(12)(v)(A) through (O) of this section, as applicable for the tested model.
 - (A) Fuel gas delivery pressure and temperature.
 - (B) Fuel gas moisture range.
 - (C) Purge gas usage range.
 - (D) Condensate (liquid fuel) separation range.
 - (E) Combustion zone temperature range. This is required for all devices that measure this parameter.
 - (F) Excess air range.
 - (G) Flame arrestor(s).
 - (H) Burner manifold.
 - (I) Pilot flame indicator.

(J) Pilot flame design fuel and calculated or measured fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) The test report must include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, strip charts, or other graphic presentations of the data annotated with test times and calibration values.

(e) *Continuous compliance for combustion control devices tested by the manufacturer in accordance with paragraph (d) of this section.* This paragraph applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (d) of this section. Owners or operators must demonstrate that a control device achieves the performance requirements in (d)(11) of this section by installing a device tested under paragraph (d) of this section, complying with the criteria specified in paragraphs (e)(1) through (8) of this section and maintaining the records specified in A.5(a)(6) or E.2(a)(1)(ii).

(1) The inlet gas flow rate must be equal to or less than the maximum specified by the manufacturer.

(2) A pilot flame must be present at all times of operation.

(3) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of EPA Method 22, 40 CFR part 60, appendix A-7, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(4) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(5) Following return to operation from maintenance or repair activity, each device must pass an EPA Method 22, 40 CFR part 60, appendix A-7, visual observation as described in paragraph (e)(3) of this section.

(6) If the owner or operator operates a combustion control device model tested under this section, an electronic copy of the performance test results required by this section shall be submitted via email to Oil_and_Gas_PT@EPA.GOV unless the test results for that model of combustion control device are posted at the following Web site: epa.gov/airquality/oilandgas/.

(7) Ensure that each enclosed combustion control device is maintained in a leak free condition.

(8) Operate each control device following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

G Equipment VOC Leaks at Natural Gas Processing Plants

G.1 Applicability

(a) The group of all equipment, except compressors and sampling connection systems, within a process unit located at an onshore natural gas processing plant.

(b) Equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, field gas gathering system, or liquefied natural gas unit is covered by the requirements of section G.2 if it is located at an onshore natural gas processing plant. Equipment not located at the onshore natural gas processing plant site is exempt from the requirements of section G.2.

(c) The equipment within a process unit subject to VOC emission control requirements located at onshore natural gas processing plants is exempt from this section if they are subject to and controlled according to subparts VVa or GGGa of 40 CFR part 60.

G.2 What VOC Emission Requirements Apply to Equipment at a Natural Gas Processing Plant?

(a) You must comply with the requirements of sections G.5.1 through G.5.9, except as provided in section G.3.

(b) You may elect to comply with the requirements of sections G.6.1 and G.6.2, as an alternative.

(c) You must comply with the provisions of sections G.7 and G.8 of this section, except as provided in section G.3.

G.3 What Exceptions Apply to the Equipment Leak VOC Emission Control Requirements for Equipment at Natural Gas Processing Plants?

(a) You may comply with the following exceptions to the provisions of section G.2.

(b)(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in section G.7(b) except as provided in paragraph (b)(4) of this section, and section G.5.2 of this rule.

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3)(i) When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in section G.5.7.

(ii) A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

(4)(i) Any pressure relief device that is located in a non-fractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are on-site, instead of within 5 days as specified in paragraph (b)(1) of this section and section G.5.2(b)(1).

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section must be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service that are located at a non-fractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of sections G.5.3(a)(1), G.5.5(a), G.5.9(a), and paragraph (b)(1) of this section.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of sections G.5.3(a)(1), G.5.5(a), G.5.9(a), and paragraph (b)(1) of this section.

(e) An owner or operator may use the following provisions instead of section G.7(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150°C (302°F) as determined by ASTM Method D86-96.

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150°C (302°F) as determined by ASTM Method D86-96.

G.4 How Do I Demonstrate Initial and Continued Compliance with the VOC Emission Control Requirements for Equipment at Natural Gas Processing Plants?

For equipment subject to VOC emission control requirements at natural gas processing plants, initial and continuous compliance with the VOC requirements is demonstrated if you are in compliance with the requirements of sections G.5.1 through G.5.9, except as provided in section G.3; G.6, as an alternative; and G.7 and G.8, except as provided in section G.3

G.5 What VOC Emission Control Requirements Apply to Equipment at Natural Gas Processing Plants

G.5.1 VOC Emission Control Requirements: General

(a) Each owner or operator subject to the provisions of this rule shall demonstrate compliance with the requirements of sections G.5.2 through G.5.8 for all equipment within 180 days and for G.5.9 within 12 months of the compliance date established by your regulatory authority.

(b) Compliance with sections G.5.2 to G.5.9 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in G.7.

G.5.2 What Equipment VOC Emission Control Requirements Apply to Pressure Relief Devices in Gas/Vapor Service?

(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in section G.7(c).

(b)(1) After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in section G.5.7.

(2) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in section G.7(c).

(c) Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in section G.5.8 is exempted from the requirements of paragraphs (a) and (b) of this section.

(d)(1) Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of paragraphs (a) and (b) of this section, provided the owner or operator complies with the requirements in paragraph (d)(2) of this section.

(2) After each pressure release, a new rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in section G.5.7.

G.5.3 What Equipment VOC Emission Control Requirements Apply to Pumps in Light Liquid Service?

(a)(1) Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in G.7(b), except as provided in paragraphs (d), (e), and (f) of this section. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in paragraphs (d), (e), and (f) of this section.

(2) Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal.

(b)(1) The instrument reading that defines a leak is specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) 5,000 parts per million (ppm) or greater for pumps handling polymerizing monomers;

(ii) 2,000 ppm or greater for all other pumps.

(2) If there are indications of liquids dripping from the pump seal, the owner or operator shall follow the procedure specified in either paragraph (b)(2)(i) or (ii) of this section. This requirement does not apply to a pump that was monitored after a previous weekly inspection and the instrument reading was less than the concentration specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable.

(i) Monitor the pump within 5 days as specified in G.7(b). A leak is detected if the instrument reading measured during monitoring indicates a leak as specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable. The leak shall be repaired using the procedures in paragraph (c) of this section.

(ii) Designate the visual indications of liquids dripping as a leak, and repair the leak using either the procedures in paragraph (c) of this section or by eliminating the visual indications of liquids dripping.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in G.5.7.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the practices described in paragraphs (c)(2)(i) and (ii) of this section, where practicable.

(i) Tightening the packing gland nuts;

(ii) Ensuring that the seal flush is operating at design pressure and temperature.

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a) of this section, provided the requirements specified in paragraphs (d)(1) through (6) of this section are met.

(1) Each dual mechanical seal system is:

(i) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(ii) Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of G.5.8; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(2) The barrier fluid system is in heavy liquid service or is not in VOC service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4)(i) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

(ii) If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the owner or operator shall follow the procedure specified in either paragraph (d)(4)(ii)(A) or (B) of this section prior to the next required inspection.

(A) Monitor the pump within 5 days as specified in G.7(b) to determine if there is a leak of VOC in the barrier fluid. If an instrument reading of 2,000 ppm or greater is measured, a leak is detected.

(B) Designate the visual indications of liquids dripping as a leak.

(5)(i) Each sensor as described in paragraph (d)(3) is checked daily or is equipped with an audible alarm.

(ii) The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(iii) If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph (d)(5)(ii) of this section, a leak is detected.

(6)(i) When a leak is detected pursuant to paragraph (d)(4)(ii)(A) of this section, it shall be repaired as specified in paragraph (c) of this section.

(ii) A leak detected pursuant to paragraph (d)(5)(iii) of this section shall be repaired within 15 days of detection by eliminating the conditions that activated the sensor.

(iii) A designated leak pursuant to paragraph (d)(4)(ii)(B) of this section shall be repaired within 15 days of detection by eliminating visual indications of liquids dripping.

(e) Any pump that is designated, as described in G.8(a)(5)(ii), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) of this section if the pump:

(1) Has no externally actuated shaft penetrating the pump housing;

(2) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in G.7(c); and

(3) Is tested for compliance with paragraph (e)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(f) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process or to a fuel gas system or to a control device that complies with the requirements of G.5.8, it is exempt from paragraphs (a) through (e) of this section.

(g) Any pump that is designated, as described in G.8(a)(6)(i), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:

(1) The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section; and

(2) The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

(h) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (a)(2) and (d)(4) of this section, and the daily requirements of paragraph (d)(5) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

G.5.4 What Equipment VOC Emission Control Requirements Apply to Open-Ended Valves or Lines?

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in paragraphs (d) and (e) of this section.

(2) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

(b) Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(c) When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) of this section at all other times.

(d) Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs (a) through (c) of this section.

(e) Open-ended valves or lines containing materials which would auto-catalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in paragraphs (a) through (c) of this section are exempt from the requirements of paragraphs (a) through (c) of this section.

G.5.5 What Equipment VOC Emission Control Requirements Apply to Valves in Gas/Vapor Service and in Light Liquid Service?

(a)(1) Each valve shall be monitored monthly to detect leaks by the methods specified in G.7(b) and shall comply with paragraphs (b) through (e) of this section, except as provided in paragraphs (f), (g), and (h) of this section and sections G.6.1 and G.6.2.

(2) A valve that begins operation in gas/vapor service or light liquid service after the compliance date for the process unit must be monitored according to paragraphs (a)(2)(i) or (ii),

except for a valve that replaces a leaking valve and except as provided in paragraphs (f), (g), and (h) of this section and sections G.6.1 and G.6.2.

(i) Monitor the valve as in paragraph (a)(1) of this section. The valve must be monitored for the first time within 30 days after the end of its startup period to ensure proper installation.

(ii) If the existing valves in the process unit are monitored in accordance with section G.6.1 or section G.6.2, count the new valve as leaking when calculating the percentage of valves leaking as described in section G.6.2(b)(5). If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.

(b) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(c)(1)(i) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(ii) As an alternative to monitoring all of the valves in the first month of a quarter, an owner or operator may elect to subdivide the process unit into two or three subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The owner or operator must keep records of the valves assigned to each subgroup.

(2) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

(d)(1) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in section G.5.7.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) First attempts at repair include, but are not limited to, the following best practices where practicable:

- (1) Tightening of bonnet bolts;
- (2) Replacement of bonnet bolts;
- (3) Tightening of packing gland nuts;
- (4) Injection of lubricant into lubricated packing.

(f) Any valve that is designated, as described in section G.8(a)(5)(ii), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) of this section if the valve:

- (1) Has no external actuating mechanism in contact with the process fluid,
- (2) Is operated with emissions less than 500 ppm above background as determined by the method specified in section G.7(c), and
- (3) Is tested for compliance with paragraph (f)(2) of this section initially upon designation, annually, and at other times requested by the permitting authority.

(g) Any valve that is designated, as described in section G.8(a)(6)(i), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

- (1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section, and
- (2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

(h) Any valve that is designated, as described in section G.8(a)(6)(ii), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) The process unit within which the valve is located either has less than 3.0 percent of its total number of valves designated as difficult-to-monitor by the owner or operator.

(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

G.5.6 What Equipment VOC Emission Control Requirements Apply to Pumps, Valves, and Connectors in Heavy Liquid Service and Pressure Relief Devices in Light Liquid or Heavy Liquid Service?

(a) If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service, the owner or operator shall follow either one of the following procedures:

(1) The owner or operator shall monitor the equipment within 5 days by the method specified in section G.7(b) and shall comply with the requirements of paragraphs (b) through (d) of this section.

(2) The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in section G.5.7.

(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) First attempts at repair include, but are not limited to, the best practices described under sections G.5.3(c)(2) and G.5.5(e).

G.5.7 What Delay of Repair of Equipment Requirements Apply When Equipment Component Leaks Have Been Detected?

(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.

(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

(c) Delay of repair for valves and connectors will be allowed if:

(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with section G.5.8.

(d) Delay of repair for pumps will be allowed if:

(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(e) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be

allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(f) When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition.

G.5.8 What VOC Emission Control Requirements Apply for Closed Vent Systems and Control Devices?

(a) Owners or operators of closed vent systems and control devices used to comply with provisions of this rule shall comply with the provisions of this section.

(b) Vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95.0 percent or greater.

(c) Each enclosed combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) shall be designed to reduce the mass content of VOC emissions by 95.0 percent or greater in accordance with the requirements of section F(b).

(d) Flares used to comply with this subpart shall comply with the requirements of §60.18.

(e) Owners or operators of control devices used to comply with the provisions of this rule shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs.

(f) Except as provided in paragraphs (i) through (k) of this section, each closed vent system shall be inspected according to the procedures and schedule specified in paragraphs (f)(1) and (2) of this section.

(1) If the vapor collection system or closed vent system is constructed of hard-piping, the owner or operator shall comply with the requirements specified in paragraphs (f)(1)(i) and (ii) of this section:

- (i) Conduct an initial inspection according to the procedures in section G.7(b); and
- (ii) Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.

(2) If the vapor collection system or closed vent system is constructed of ductwork, the owner or operator shall:

- (i) Conduct an initial inspection according to the procedures in section G.7(b); and
 - (ii) Conduct annual inspections according to the procedures in section G.7(b).
- (g) Leaks, as indicated by an instrument reading greater than 500 ppmv above background or by visual inspections, shall be repaired as soon as practicable except as provided in paragraph (h) of this section.

(1) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(2) Repair shall be completed no later than 15 calendar days after the leak is detected.

(h) Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.

(i) If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section.

(j) Any parts of the closed vent system that are designated, as described in paragraph (l)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (j)(1) and (2) of this section:

(1) The owner or operator determines that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (f)(1)(i) or (f)(2) of this section; and

(2) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(k) Any parts of the closed vent system that are designated, as described in paragraph (l)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (k)(1) through (3) of this section:

(1) The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(2) The owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and

(3) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

(l) The owner or operator shall record the information specified in paragraphs (l)(1) through (5) of this section.

(1) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(2) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(3) For each inspection during which a leak is detected, a record of the information specified in section G.8(a)(3).

(4) For each inspection conducted in accordance with section G.7(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(5) For each visual inspection conducted in accordance with paragraph (f)(1)(ii) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(m) Closed vent systems and control devices used to comply with provisions of this rule shall be operated at all times when emissions may be vented to them.

G.5.9 What VOC Emission Control Requirements Apply to Connectors in Gas/Vapor Service and in Light Liquid Service?

(a) The owner or operator shall initially monitor all connectors in the process unit for leaks within 12 months of the compliance date. If all connectors in the process unit have been monitored for leaks prior to the compliance date, no initial monitoring is required provided either no process changes have been made since the monitoring or the owner or operator can determine that the results of the monitoring, with or without adjustments, reliably demonstrate compliance despite process changes. If required to monitor because of a process change, the owner or operator is required to monitor only those connectors involved in the process change.

(b) Except as allowed in section G.5.7 or as specified in paragraph (e) of this section, the owner or operator shall monitor all connectors in gas and vapor and light liquid service as specified in paragraphs (a) and (b)(3) of this section.

(1) The connectors shall be monitored to detect leaks by the method specified in section G.7(b) and, as applicable, section G.7(c).

(2) If an instrument reading greater than or equal to 500 ppm is measured, a leak is detected.

(3) The owner or operator shall perform monitoring, subsequent to the initial monitoring required in paragraph (a) of this section, as specified in paragraphs (b)(3)(i) through (iii) of this section, and shall comply with the requirements of paragraphs (b)(3)(iv) and (v) of this section. The required period in which monitoring must be conducted shall be determined from paragraphs (b)(3)(i) through (iii) of this section using the monitoring results from the preceding monitoring period. The percent leaking connectors shall be calculated as specified in paragraph (c) of this section.

(i) If the percent leaking connectors in the process unit was greater than or equal to 0.5 percent, then monitor within 12 months (1 year).

(ii) If the percent leaking connectors in the process unit was greater than or equal to 0.25 percent but less than 0.5 percent, then monitor within 4 years. An owner or operator may comply with the requirements of this paragraph by monitoring at least 40 percent of the connectors within 2 years of the start of the monitoring period, provided all connectors have been monitored by the end of the 4-year monitoring period.

(iii) If the percent leaking connectors in the process unit was less than 0.25 percent, then monitor as provided in paragraph (b)(3)(iii)(A) of this section and either paragraph (b)(3)(iii)(B) or (b)(3)(iii)(C) of this section, as appropriate.

(A) An owner or operator shall monitor at least 50 percent of the connectors within 4 years of the start of the monitoring period.

(B) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is greater than or equal to 0.35 percent of the monitored connectors, the owner or operator shall monitor as soon as practical, but within the next 6

months, all connectors that have not yet been monitored during the monitoring period. At the conclusion of monitoring, a new monitoring period shall be started pursuant to paragraph (b)(3) of this section, based on the percent of leaking connectors within the total monitored connectors.

(C) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is less than 0.35 percent of the monitored connectors, the owner or operator shall monitor all connectors that have not yet been monitored within 8 years of the start of the monitoring period.

(iv) If, during the monitoring conducted pursuant to paragraphs (b)(3)(i) through (iii) of this section, a connector is found to be leaking, it shall be re-monitored once within 90 days after repair to confirm that it is not leaking.

(v) The owner or operator shall keep a record of the start date and end date of each monitoring period under this section for each process unit.

(c) For use in determining the monitoring frequency, as specified in paragraphs (a) and (b)(3) of this section, the percent leaking connectors as used in paragraphs (a) and (b)(3) of this section shall be calculated by using the following equation:

$$\%C_L = C_L / C_t * 100$$

Where:

$\%C_L$ = Percent of leaking connectors as determined through periodic monitoring required in paragraphs (a) and (b)(3)(i) through (iii) of this section.

C_L = Number of connectors measured at 500 ppm or greater, by the method specified in G.7(b).

C_t = Total number of monitored connectors in the process unit.

(d) When a leak is detected pursuant to paragraphs (a) and (b) of this section, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as

provided in section G.5.7. A first attempt at repair as defined in this rule shall be made no later than 5 calendar days after the leak is detected.

(e) Any connector that is designated, as described in section G.8(a)(6)(i), as an unsafe-to-monitor connector is exempt from the requirements of paragraphs (a) and (b) of this section if:

(1) The owner or operator of the connector demonstrates that the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (a) and (b) of this section; and

(2) The owner or operator of the connector has a written plan that requires monitoring of the connector as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (d) of this section if a leak is detected.

(f) *Inaccessible, ceramic, or ceramic-lined connectors.* (1) Any connector that is inaccessible or that is ceramic or ceramic-lined (e.g., porcelain, glass, or glass-lined), is exempt from the monitoring requirements of paragraphs (a) and (b) of this section, from the leak repair requirements of paragraph (d) of this section, and from recordkeeping and reporting requirements. An inaccessible connector is one that meets any of the provisions specified in paragraphs (f)(1)(i) through (vi) of this section, as applicable:

(i) Buried;

(ii) Insulated in a manner that prevents access to the connector by a monitor probe;

(iii) Obstructed by equipment or piping that prevents access to the connector by a monitor probe;

(iv) Unable to be reached from a wheeled scissor-lift or hydraulic-type scaffold that would allow access to connectors up to 7.6 meters (25 feet) above the ground;

(v) Inaccessible because it would require elevating the monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold; or

(vi) Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines, or would risk damage to equipment.

(2) If any inaccessible, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere shall be eliminated as soon as practical.

(g) Except for instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph (f) of this section, identify the connectors subject to the requirements of this rule. Connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this rule are identified as a group, and the number of connectors subject to the requirements is indicated.

G.6 Alternative Standards

G.6.1 Alternative Standards for Valves—Allowable Percentage of Valves Leaking

(a) An owner or operator may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

(b) The following requirements shall be met if an owner or operator wishes to comply with an allowable percentage of valves leaking:

(1) An owner or operator must notify the permitting authority that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in section G.8(b)(4).

(2) A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the permitting authority.

(3) If a valve leak is detected, it shall be repaired in accordance with section G.5.5(d) and (e).

(c) Performance tests shall be conducted in the following manner:

(1) All valves in gas/vapor and light liquid service within the natural gas processing plant subject to VOC emission control requirements shall be monitored within one week by the methods specified in section G.7(b).

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3) The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the natural gas processing plant subject to VOC emission control requirements.

(d) Owners and operators who elect to comply with this alternative standard shall not have a natural gas processing plant subject to the equipment component VOC emission control requirements with a leak percentage greater than 2.0 percent, determined as described in section G.7(h).

G.6.2 Alternative Standards for Valves—Skip Period Leak Detection and Repair

(a)(1) An owner or operator may elect to comply with one of the alternative work practices specified in paragraphs (b)(2) and (3) of this section.

(2) An owner or operator must notify the permitting authority before implementing one of the alternative work practices.

(b)(1) An owner or operator shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in section G.5.5.

(2) After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(3) After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(4) If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in section G.5.5 but can again elect to use this section.

(5) The percent of valves leaking shall be determined as described in section G.7(h).

(6) An owner or operator must keep a record of the percent of valves found leaking during each leak detection period.

(7) A valve that begins operation in gas/vapor service or light liquid service after the compliance date for a process unit following one of the alternative standards in this section must be monitored in accordance with section G.5.5(a)(2)(i) or (ii) before the provisions of this section can be applied to that valve.

G.7 Equipment Leak Test Methods and Procedures

(a) In conducting the performance tests, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section.

(b) The owner or operator shall determine compliance with the standards in sections G.5.2 through G.5.9, and as follows:

(1) EPA Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in EPA Method 21 of appendix A-7 of this part. The following calibration gases shall be used:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppm greater than the leak definition concentration of the equipment monitored. If the monitoring

instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppm above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately equal to 10,000 ppm. If only one scale on an instrument will be used during monitoring, the owner or operator need not calibrate the scales that will not be used during that day's monitoring.

(2) A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in EPA Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in section G.8(a)(5)(v). Divide these readings by the initial calibration value and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by $(100 \text{ minus the percent of negative drift} / \text{divided by } 100)$ must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by $(100 \text{ plus the percent of positive drift} / \text{divided by } 100)$ may be re-monitored.

(c) The owner or operator shall determine compliance with the no-detectable-emission standards in sections G.5.2, G.5.3(e), G.5.5(f), and G.5.8(e) as follows:

(1) The requirements of paragraph (b) shall apply.

(2) EPA Method 21 of appendix A-7 of this part shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

(d) The owner or operator shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

(1) Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-93, E168-92, or E260-96 must be used.

(2) Organic compounds that are considered by the permitting authority to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

(3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the permitting authority disagrees with the judgment, paragraphs (d)(1) and (2) of this section shall be used to resolve the disagreement.

(e) The owner or operator shall demonstrate that a piece of equipment is in light liquid service by showing that all the following conditions apply:

(1) The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. H₂O at 68 °F). Standard reference texts or ASTM D2879-83, 96, or 97 shall be used to determine the vapor pressures.

(2) The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H₂O at 68 °F) is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(f) Samples used in conjunction with paragraphs (d), (e), and (g) of this section shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

(g) The owner or operator shall determine compliance with the standards of flares as follows:

(1) EPA Method 22 of appendix A-7 of this part shall be used to determine visible emissions.

(2) A thermocouple or any other equivalent device¹⁶⁰ shall be used to monitor the presence of a pilot flame in the flare.

(3) The maximum permitted velocity for air assisted flares shall be computed using the following equation:

$$V_{\max} = K_1 + K_2 H_T$$

Where:

$V_{\max}$ = Maximum permitted velocity, m/sec (ft/sec).

H_T = Net heating value of the gas being combusted, MJ/scm (Btu/scf).

K_1 = 8.706 m/sec (metric units) = 28.56 ft/sec (English units).

K_2 = 0.7084 m⁴/(MJ-sec) (metric units) = 0.087 ft⁴/(Btu-sec) (English units).

¹⁶⁰ The equivalent device must be reviewed and approved by EPA through the SIP review process.

(4) The net heating value (H_T) of the gas being combusted in a flare shall be computed using the following equation:

$$H_T = K \sum_{i=1}^n C_i H_i$$

Where:

K = Conversion constant, 1.740×10^{-7} (g-mole)(MJ)/(ppm-scm-kcal) (metric units) = 4.674×10^{-6} [(g-mole)(Btu)/(ppm-scf-kcal)] (English units).

C_i = Concentration of sample component “i,” ppm

H_i = net heat of combustion of sample component “i” at 25°C and 760 mm Hg (77°F and 14.7 psi), kcal/g-mole.

(5) EPA Method 18 of appendix A-6 of this part or ASTM D6420-99 (2004) (where the target compound(s) are those listed in Section 1.1 of ASTM D6420-99, and the target concentration is between 150 parts per billion by volume and 100 ppmv) and ASTM D2504-67, 77, or 88 (Reapproved 1993) shall be used to determine the concentration of sample component “i.”

(6) ASTM D2382-76 or 88 or D4809-95 shall be used to determine the net heat of combustion of component “i” if published values are not available or cannot be calculated.

(7) EPA Method 2, 2A, 2C, or 2D of appendix A-7 of this part, as appropriate, shall be used to determine the actual exit velocity of a flare. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.

(h) The owner or operator shall determine compliance with section G.6.1 or section G.6.2 as follows:

(1) The percent of valves leaking shall be determined using the following equation:

$$\%V_L = (V_L / V_T) * 100$$

Where:

$\%V_L$ = Percent leaking valves.

V_L = Number of valves found leaking.

V_T = The sum of the total number of valves monitored.

(2) The total number of valves monitored shall include difficult-to-monitor and unsafe-to-monitor valves only during the monitoring period in which those valves are monitored.

(3) The number of valves leaking shall include valves for which repair has been delayed.

(4) Any new valve that is not monitored within 30 days of being placed in service shall be included in the number of valves leaking and the total number of valves monitored for the monitoring period in which the valve is placed in service.

(5) If the process unit has been subdivided in accordance with section G.5.5(c)(1)(ii), the sum of valves found leaking during a monitoring period includes all subgroups.

(6) The total number of valves monitored does not include a valve monitored to verify repair.

G.8 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements.* Each owner or operator subject to the VOC equipment leak requirements specified in section G shall maintain the records specified in paragraphs (a)(1) through (10), as applicable, onsite or at the nearest local field office for at least five years.

(1) An owner or operator of more than one facility subject to the requirements of section G may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

(2) The owner or operator shall record the information specified in paragraphs (a)(2)(i) through (v) of this section for each monitoring event required by sections G.5.3, G.5.5, G.5.6, G.5.9, and G.6.2.

(i) Monitoring instrument identification.

(ii) Operator identification.

(iii) Equipment identification.

(iv) Date of monitoring.

(v) Instrument reading.

(3) When each leak is detected as specified in sections G.5.3, G.5.5, G.5.6, G.5.9, and G.6.2, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(i) The instrument and operator identification numbers and the equipment identification number, except when indications of liquids dripping from a pump are designated as a leak.

(ii) The date the leak was detected and the dates of each attempt to repair the leak.

(iii) Repair methods applied in each attempt to repair the leak.

(iv) Maximum instrument reading measured by EPA Method 21 of appendix A-7 of this part at the time the leak is successfully repaired or determined to be non-repairable, except when a pump is repaired by eliminating indications of liquids dripping.

(v) “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(ix) The date of successful repair of the leak.

(4) The following information pertaining to the design requirements for closed vent systems and control devices described in section G.5.8 shall be recorded and kept in a readily accessible location:

(i) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(ii) The dates and descriptions of any changes in the design specifications.

(iii) A description of the parameter or parameters monitored, as required in section G.5.8(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(iv) Periods when the closed vent systems and control devices required in sections G.5.2 and G.5.3 are not operated as designed, including periods when a flare pilot light does not have a flame.

(v) Dates of startups and shutdowns of the closed vent systems and control devices required in sections G.5.2 and G.5.3.

(5) The following information pertaining to all equipment subject to the requirements in sections G.5.1 to G.5.9 shall be recorded in a log that is kept in a readily accessible location:

(i) A list of identification numbers for equipment subject to the requirements of this rule.

(ii)(A) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of sections G.5.3(e) and G.5.5(f).

(B) The designation of equipment as subject to the requirements of sections G.5.3(e) or section G.5.5(f) shall be signed by the owner or operator. Alternatively, owner or operator may establish a mechanism¹⁶¹ with their permitting authority that satisfies this requirement.

(C) A list of equipment identification numbers for pressure relief devices required to comply with section G.5.2.

(iii)(A) The dates of each compliance test as required in sections G.5.2, G.5.3(e), and G.5.5(f).

(B) The background level measured during each compliance test.

(C) The maximum instrument reading measured at the equipment during each compliance test.

(iv) A list of identification numbers for equipment in vacuum service.

(v) Records of the information specified in paragraphs (a)(5)(v)(A) through (F) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of EPA Method 21 of appendix A-7 of this part and section G.7(b).

(A) Date of calibration and initials of operator performing the calibration.

(B) Calibration gas cylinder identification, certification date, and certified concentration.

(C) Instrument scale(s) used.

(D) A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of EPA Method 21 of appendix A-7 of this part.

¹⁶¹ The mechanism must be reviewed and approved by EPA through the SIP review process.

(E) Results of each calibration drift assessment required by section G.7(b)(2) (i.e., instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).

(F) If an owner or operator makes their own calibration gas, a description of the procedure used.

(vi) The connector monitoring schedule for each process unit as specified in section G.5.9(b)(3)(v).

(vii) Records of each release from a pressure relief device subject to section G.5.2.

(6) The following information pertaining to all valves subject to the requirements of section G.5.5(g) and (h), all pumps subject to the requirements of section G.5.3(g), and all connectors subject to the requirements of section G.5.9(e) shall be recorded in a log that is kept in a readily accessible location:

(i) A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.

(ii) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(7) The following information shall be recorded for valves complying with section G.6.2:

(i) A schedule of monitoring.

(ii) The percent of valves found leaking during each monitoring period.

(8) The following information shall be recorded in a log that is kept in a readily accessible location:

(i) Design criterion required in section G.5.3(d)(5) and explanation of the design criterion; and

(ii) Any changes to this criterion and the reasons for the changes.

(A) The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions:

(1) An analysis demonstrating the design capacity of the natural gas processing plant,

(2) A statement listing the feed or raw materials and products from the processing plant(s) and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

(3) An analysis demonstrating that equipment is not in VOC service.

(9) Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

(10) The following recordkeeping requirements apply to pumps in light liquid service, pressure relief devices in gas/vapor service, valves in gas/vapor service and light liquid service, pumps, valves and connectors in light heavy liquid service and pressure relief devices in light liquid or heavy liquid service, connectors in gas/vapor service and in light liquid service, and alternative standards for valves.

(i) When each leak is detected, as specified in section G.5.2, G.5.3(b)(2), G.5.5, G.5.6, G.5.9 and G.6.2, a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(ii) When each leak is detected, as specified in section G.5.2, G.5.3(b)(2), G.5.5, G.5.6, G.5.9 and G.6.2, the following information must be recorded in a log and shall be kept for 2 years in a readily accessible location:

(A) The instrument and operator identification numbers and the equipment identification number.

(B) The date the leak was detected and the dates of each attempt to repair the leak.

(C) Repair methods applied in each attempt to repair the leak.

(D) “Above 500 ppm” if the maximum instrument reading measured by the methods specified in paragraph (a) of this section after each repair attempt is 500 ppm or greater.

(E) “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(F) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(G) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(H) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(I) The date of successful repair of the leak.

(J) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of section G.5. The designation of equipment that has no detectable emissions that is subject to the provisions of section G.5 must be signed by the owner or operator.

(b) *Reporting requirements.* Each owner or operator subject to the VOC equipment leak requirements shall comply with the reporting requirements of paragraphs (b)(1) through (5).

(1) Each owner or operator subject to the equipment leak VOC emission control requirements of section G.5 shall submit semiannual reports to the permitting authority beginning 6 months after a facility becomes subject to VOC emission control requirements of section G.5.8.

(2) The initial semiannual report to the permitting authority shall include the following information:

(i) Process unit identification.

(ii) Number of valves subject to the requirements of section G.5.5, excluding those valves designated for no detectable emissions under the provisions of section G.5.5(f).

(iii) Number of pumps subject to the requirements of section G.5.3, excluding those pumps designated for no detectable emissions under the provisions of section G.5.3(e) and those pumps complying with section G.5.3(f).

(iv) Number of connectors subject to the requirements of section G.5.9.

(v) Number of pressure relief devices subject to the requirements, except for those pressure relief devices designated for no detectable emissions under the provisions of section G.5.2 (a) and those pressure relief devices complying with section G.5.2 (c).

(3) All semiannual reports to the permitting authority shall include the following information:

(i) Process unit identification.

(ii) For each month during the semiannual reporting period,

(A) Number of valves for which leaks were detected as described in section G.5.5(b) or section G.6.2,

(B) Number of valves for which leaks were not repaired as required in section G.5.5(d)(1),

(C) Number of pumps for which leaks were detected as described in section G.5.3(b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),

(D) Number of pumps for which leaks were not repaired as required in section G.5.3(c)(1) and (d)(6),

(E) Number of compressors for which leaks were detected as described in section G.5.3(f),

(F) Number of connectors for which leaks were detected as described in section G.5.9(b)

(G) Number of connectors for which leaks were not repaired as required in section G.5.9(d), and

(H) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(iii) An owner or operator must include the following information in all semiannual reports:

(A) Number of pressure relief devices for which leaks were detected; and

(B) Number of pressure relief devices for which leaks were not repaired.

(iv) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(v) Revisions to items reported according to paragraph (b)(1) of this section if changes have occurred since the initial report or subsequent revisions to the initial report.

(4) An owner or operator electing to comply with the provisions of section G.6.1 or section G.6.2 shall notify the permitting authority of the alternative standard selected 90 days before implementing either of the provisions.

(5) An owner or operator shall report the results of all performance tests to the permitting authority.

G.9 Definitions

As used in this model rule, all terms not defined in section G for equipment leaks at natural gas processing plants shall have the meaning given them in subpart VVa of part 60 and the following terms shall have the specific meanings given them.

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

Equipment, as used in the standards and requirements in this rule relative to the equipment leaks of VOC from onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by those same standards and requirements in this rule.

Field gas means feedstock gas entering the natural gas processing plant.

Field gas gathering means the system used transport field gas from a field to the main pipeline in the area.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions. Completion combustion devices include pit flares.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Gas processing plant process unit means equipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in sections G.7(e) and G.3(e)(2).

In wet gas service means that a piece of equipment (except compressors and sampling connection systems) contains or contacts the field gas before the extraction step at a gas processing plant process unit.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Non-fractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

Process unit means components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Underground storage vessel means a storage vessel stored below ground.

H Pneumatic Pumps: VOC Emissions Control Requirements

H.1 Applicability

Each pneumatic pump, which is a natural gas-driven diaphragm pump located at:

(a) A natural gas processing plant; or

(b) A well site. A natural gas-driven diaphragm pump at a well site that is in operation less than 90 days per calendar year is not a source subject to VOC requirements under this rule provided that the owner/operator keeps records of the days of operation each calendar year and submits such records to the regulatory authority upon request. For the purposes of this rule, any period of operation during a calendar day counts toward the 90 calendar day threshold.

For purposes of the requirements specified in this section, we refer to these pumps as natural gas-driven pneumatic pumps.

H.2 What VOC Emission Reduction Requirements Apply to Natural Gas-Driven Pneumatic Pumps?

For each natural gas-driven pneumatic pump, you must comply with the VOC emission control requirements, based on VOC, in either paragraph (a) or (b)(1) of this section, as applicable.

(a) Each natural gas-driven pneumatic pump at a natural gas processing plant must have a VOC emission rate of zero.

(b)(1) For each natural gas-driven pneumatic pump at a well site, you must reduce natural gas emissions by 95.0 percent, except as provided in paragraphs (b)(2), (3) and (4) of this section.

(2) You are not required to install a control device solely for the purpose of complying with the 95.0 percent reduction requirement of paragraph (b)(1) of this section. If you do not

have a control device installed on site by the compliance date established by your regulatory authority and you do not have the ability to route to a process, then you must comply instead with the provisions of paragraph (b)(2)(i) and (ii) of this section.

(i) Submit a certification in accordance with section H.5(b)(1)(i) in your next annual report, certifying that there is no available control device or process on site and maintain the records in section H.5(a)(1)(i) and (ii).

(ii) If you subsequently install a control device or have the ability to route to a process, you are no longer required to submit the certification in section H.2(b)(2)(i) and must submit the information in section H.5(b)(2) in your next annual report and maintain the records in sections H.5(a)(1)(i), (ii) and (iii) and H.5(a)(2). You must be in compliance with the requirements of paragraph (b)(1) of this section within 30 days of startup of the control device or within 30 days of the ability to route to a process.

(3) If the control device available on site is unable to achieve a 95.0 percent reduction and there is no ability to route the emissions to a process, you must still route the natural gas-driven pneumatic pump's emissions to that existing control device. If you route the pneumatic pump to a control device installed on site that is designed to achieve less than a 95.0 percent reduction, you must submit the information specified in section H.5(b)(1)(iii) in your next annual report and maintain the records in sections H.5(a)(1)(i), (ii) and (iii) and H.5(a)(2).

(4) If you determine, through an engineering assessment, that routing a pneumatic pump to a control device or a process is technically infeasible, the requirements specified in paragraph (b)(4)(i) through (iv) of this section must be met.

(i) You must conduct the assessment of technical infeasibility in accordance with the criteria in paragraph (b)(4)(iii) of this section and have it certified by a qualified professional engineer in accordance with paragraph (b)(4)(ii) of this section.

(ii) The following certification, signed and dated by the qualified professional engineer shall state: "I certify that the assessment of technical infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted and this report was

prepared pursuant to the requirements of section H.2(b)(4)(iii) of this rule. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information.”

(iii) The assessment of technical feasibility to route emissions from the pneumatic pump to an existing control device on site or to a process must include, but is not limited to, safety considerations, distance from the control device, pressure losses and differentials in the closed vent system and the ability of the control device to handle the pneumatic pump emissions which are routed to them. You must prepare the assessment of technical infeasibility under the direction or supervision of the qualified professional engineer who signs the certification in accordance with paragraph (b)(2)(ii) of this section.

(iv) You must maintain the records specified in section H.5(a)(1)(iv).

(5) If the pneumatic pump is routed to a control device or a process and the control device or process is subsequently removed from the location or is no longer available, you are no longer required to be in compliance with the requirements of paragraph (b)(1) of this section, and instead must comply with paragraph (b)(2) of this section and report the change in your next annual report in accordance with section H.5(b)(2)(iii).

(c) If you use a control device or route to a process to reduce emissions, you must connect the natural gas-driven pneumatic pump subject to VOC emission control requirements through a closed vent system that meets the requirements of section D.1(b).

(d) You must demonstrate initial compliance with standards that apply to natural gas-driven pneumatic pumps subject to VOC emission requirements as required by section H.3.

(e) You must demonstrate continuous compliance with standards that apply to natural gas-driven pneumatic pump sources subject to VOC emission requirements as required by section H.4.

(f) You must perform the reporting as required by section H.5(b) and the recordkeeping as required by H.5(a).

H.3 Initial Compliance Demonstration Requirements

You must demonstrate initial compliance by the compliance date established by your regulatory authority by demonstrating compliance with the VOC emission control requirements for natural gas-driven pneumatic pumps specified in paragraphs (a) through (h) of this section, as applicable.

(a) If you own or operate a pneumatic pump located at a natural gas processing plant, your pneumatic pump must be driven by a gas other than natural gas, resulting in zero VOC emissions.

(b) If you own or operate a natural gas-driven pneumatic pump located at a well site, you must reduce emissions in accordance with section H.2(b)(1), and you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of section D.1(b).

(c) If you own or operate a natural gas-driven pneumatic pump located at a well site and there is no control device or process available on site, you must submit the certification in section H.5(b)(1)(i).

(d) If you own or operate a natural gas-driven pneumatic pump located at a well site, and you are unable to route to an existing control device due to technical infeasibility, and you are unable to route to a process, you must submit the certification in section H.5(b)(1)(ii).

(e) If you own or operate a natural gas-driven pneumatic pump located at a well site and you reduce emissions in accordance with section H.2(b)(3), you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of section D.1(b).

(f) If you are required to collect emissions from a natural gas-driven pneumatic pump through a closed vent system, you must conduct the initial closed vent system inspection required in section D.2 by the date established by your regulatory authority.

(g) You must include a listing of the natural gas-driven pneumatic pumps subject to VOC emission requirements specified in paragraphs (a) through (e) of this section in the initial annual report submitted for your natural gas-driven pneumatic pump according to the requirements of section H.5(b).

(h) You must maintain the records as specified in section H.5(a) for each natural gas-driven pneumatic pump subject to the VOC emission control requirements of section H.

H.4 Continuous Compliance Demonstration Requirements

For each natural gas-driven pneumatic pump you must demonstrate continuous compliance according to paragraphs (a) and (b) of this section.

(a) If you are required to collect emissions from a natural gas-driven pneumatic pump through a closed vent system, you must conduct the periodic closed vent system inspections required in section D.2, as applicable.

(b) You must submit the annual reports required by section H.5(b) and maintain the records as specified in section H.5(a).

H.5 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements.*

(1) For each natural gas-driven pneumatic pump subject to VOC emission control requirements, you must maintain the records identified in paragraphs (a)(1)(i) through (v) of this section, as applicable, onsite or at the nearest local field office for at least five years.

(i) Records of the date that an individual natural gas-driven pneumatic pump is required to comply with the rule (as established by the regulatory authority), location and manufacturer specifications for each natural gas-driven pneumatic pump.

(ii) Records of deviations in cases where the natural gas-driven pneumatic pump was not operated in compliance with the requirements specified in section H.2.

(iii) Records on the control device used for control of emissions from a natural gas-driven pneumatic pump including the installation date, manufacturer's specifications, and if the control device is designed to achieve less than a 95.0 percent emission reduction, a design evaluation or manufacturer's specifications indicating the percentage reduction the control device is designed to achieve.

(iv) Records substantiating a claim according to H.2(b)(4) that it is technically infeasible to capture and route emissions from a pneumatic pump to a control device or process, including the qualified professional engineer certification according to H.2(b)(4)(ii) and the records of the engineering assessment of technical infeasibility performed according to H.2.(b)(4)(iii).

(v) You must retain copies of all certifications, engineering assessments and related records for a period of five years and make them available if directed by the regulatory authority.

(2) If you are required to collect emissions from a natural gas-driven pneumatic pump through a closed vent system, you must maintain the records identified in paragraphs (a)(2)(i) through (iv) of this section, as applicable, onsite or at the nearest local field office for at least five years.

(i) Records of each closed vent system inspection required under section D.2(a) and (b).

(ii) If you are subject to the bypass requirements of section D.1(b)(3), a record of each inspection or a record of each time the key is checked out or a record of each time the alarm is sounded.

(iii) If you are subject to the closed vent system no detectable emissions requirements of section D.2(e), records of the monitoring conducted in accordance with section D.2(e).

(iv) For each closed vent system routing to a control device or process, the records of the assessment conducted according to section D.1(b)(4):

(A) A copy of the assessment conducted according to section D.1(b)(4);

(B) A copy of the certification according to section D.1(b)(4)(i); and

(C) The owner or operator shall retain copies of all certifications, assessments and any related records for a period of five years, and make them available if directed by the regulatory authority.

(b) Reporting Requirements.

For each natural gas-driven pneumatic pump subject to VOC emission control requirements, annual reports are required to include the information specified in paragraphs (b)(1) through (4) of this section.

(1) In the initial annual report, a certification that the natural gas-driven pneumatic pump meets one of the conditions described in paragraphs (b)(1)(i), (ii) or (iii) of this section.

(i) No control device or process is available on site.

(ii) A control device or process is available on site and the owner or operator has determined in accordance with H.2(b)(4) that it is technically infeasible to capture and route the emissions to the control device or process.

(iii) Emissions from the natural gas-driven pneumatic pump are routed to a control device or process. If the control device is designed to achieve less than 95.0 percent emissions reduction, specify the percent emissions reductions the control device is designed to achieve.

(2) For any natural gas-driven pneumatic pump which has been previously reported as required under paragraph (b)(1) of this section and for which a change in the reported condition has occurred during the reporting period, provide the identification of the natural gas-driven pneumatic pump and the date it was previously reported and a certification that the pneumatic pump meets one of the conditions described in paragraphs (b)(2)(i), (ii) or (iii) or (iv) of this section.

(i) A control device has been added to the location and the pneumatic pump now reports according to paragraph (b)(1)(iii) of this section.

(ii) A control device has been added to the location and the pneumatic pump now reports according to paragraph (b)(1)(ii) of this section.

(iii) A control device or process has been removed from the location or otherwise is no longer available and the pneumatic pump now report according to paragraph (b)(1)(i) of this section.

(iv) A control device or process has been removed from the location or is otherwise no longer available and the owner or operator has determined in accordance with H.2(b)(4) through an engineering evaluation that it is technically infeasible to capture and route the emissions to another control device or process.

(3) Records of deviations specified in paragraph (a)(1)(ii) of this section that occurred during the reporting period.

(4) If you are required to collect emissions from a natural gas-driven pneumatic pump through a closed vent system, the records specified in paragraphs (a)(2)(i), (ii), (iii) and (iv)(B) of this section.

H.6 Definitions

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding \$25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including, but not limited to, general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.*, a Regional Administrator of EPA); or

(4) For facilities subject to requirements:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Natural gas-driven diaphragm pump means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction

with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Qualified Professional Engineer means an individual who is licensed by a state as a Professional Engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge and experience to make the specific technical certifications required under this subpart. Professional engineers making these certifications must be currently licensed in at least one state in which the certifying official is located.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process that is operational where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well.

I Fugitive Emissions Components VOC Emissions Control Requirements

I.1 Applicability

(a) The collection of fugitive emission components at a well site with wells that produce, on average, greater than 15 barrel equivalents per day. The fugitive emissions requirements of this section do not apply to well sites that only contain wellheads. Whether a separate tank battery surface site is subject to this rule has no effect on the status of a well site that only contains wellheads.

(b) The collection of fugitive emission components at a gathering and boosting station located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or to an oil pipeline.

I.2 What VOC Emission Control Requirements Apply to the Collection of Fugitive Emission Components at a Well Site and a Gathering and Boosting Station?

For fugitive emissions, VOC emission control requirements apply to the collection of fugitive emission components at a well site and gathering and boosting station (that is located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or to an oil pipeline), as specified in paragraphs (a) through (f) of this section for monitoring the collection of fugitive emission components. These requirements are independent of the closed vent system and cover requirements in section D. The collection of fugitive emissions at a well site with a gas to oil ratio of less than 300 scf of gas per barrel of oil produced are subject only to the requirements in paragraph (g) of this section.

(a) You must monitor all fugitive emission components, as defined in section I.6, in accordance with paragraphs (b) through (e) of this section and section I.2(a) and I.3(a). You must

repair all sources of fugitive emissions in accordance with paragraph (f) of this section. You must keep records in accordance with section I.5(a) and report in accordance with section I.5(b). For purposes of this section, fugitive emissions are defined as: any visible emission from a fugitive emission component using optical gas imaging or an instrument reading of 500 ppm or greater using EPA Method 21.

(b) You must develop an emissions monitoring plan that covers the collection of fugitive emission components at well sites and gathering and boosting stations within each company-defined area in accordance with paragraphs (c) and (d) of this section.

(c) Fugitive emissions monitoring plans must include the elements specified in paragraphs (c)(1) through (c)(8) of this section, at a minimum.

(1) Frequency for conducting surveys. Monitoring surveys must be conducted at least as frequently as required by sections I.3 and section I.4 of this section.

(2) Technique for determining fugitive emissions (*i.e.*, EPA Method 21 at 40 CFR part 60, appendix A-7, or optical gas imaging).

(3) Manufacturer and model number of fugitive emission detection equipment to be used.

(4) Procedures and timeframes for identifying and fixing fugitive emission components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair. Your repair schedule must meet the requirements of paragraph (f) of this section at a minimum.

(5) Procedures and timeframes for verifying fugitive emission component repairs.

(6) Records that will be kept and the length of time records will be kept.

(7) If you are using optical gas imaging, your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii) of this section.

(i) Verification that your optical gas imaging equipment meets the specifications of paragraphs (c)(7)(i)(A) and (B) of this section. This verification is an initial verification and may be performed by the facility, by the manufacturer, or by a third party. For purposes of complying with the fugitive emissions monitoring program with optical gas imaging, a fugitive emission is defined as any visible emissions observed using optical gas imaging.

(A) Your optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.

(B) Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of ≤ 60 g/hr from a quarter inch diameter orifice.

(ii) Procedure for a daily verification check.

(iii) Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained.

(iv) Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.

(v) Procedures for conducting surveys, including the items specified in paragraphs (c)(7)(v)(A) through (C) of this section.

(A) How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.

(B) How the operator will deal with adverse monitoring conditions, such as wind.

(C) How the operator will deal with interferences (*e.g.*, steam).

(vi) Training and experience needed prior to performing surveys.

(vii) Procedures for calibration and maintenance. At a minimum, procedures must comply with those recommended by the manufacturer.

(8) If you are using EPA Method 21 at 40 CFR part 60, appendix A-7, your plan must also include the elements specified in paragraphs (c)(8)(i) and (ii) of this section. For the purposes of complying with the fugitive emissions monitoring program using EPA Method 21, a fugitive emission is defined as an instrument reading of 500 ppm or greater.

(i) Verification that your monitoring equipment meets the requirements specified in Section 6.0 of EPA Method 21 at 40 CFR part 60, appendix A-7. For purposes of instrument capability, the fugitive emissions definition shall be 500 ppm or greater methane using a FID-based instrument. If you wish to use an analyzer other than a FID-based instrument, you must develop a site-specific fugitive emission definition that would be equivalent to 500 ppm methane using a FID-based instrument (*e.g.*, 10.6 eV PID with a specified isobutylene concentration as the fugitive emission definition would provide equivalent response to your compound of interest).

(ii) Procedures for conducting surveys. At a minimum, the procedures shall ensure that the surveys comply with the relevant sections of EPA Method 21 at 40 CFR part 60, appendix A-7, including Section 8.3.1.

(d) Each fugitive emissions monitoring plan must include the elements specified in paragraphs (d)(1) through (d)(4) of this section, at a minimum, as applicable.

(1) Sitemap.

(2) If you are using OGI, a defined observation path that ensures that all fugitive emissions components are within sight of the path. The observation path must account for interferences.

(3) If you are using EPA Method 21, your plan must also include a list of fugitive emissions components to be monitored and the method for determining location of fugitive

emissions components to be monitored in the field (*e.g.*, tagging, identification on a process and instrumentation diagram, etc.).

(4) Your plan must also include the written plan developed for all of the fugitive emission components designated as difficult-to-monitor in accordance with section I.4(a)(3), and the written plan for fugitive emission components designated as unsafe-to-monitor in accordance with section I.4(a)(4).

(e) Each monitoring survey shall observe each fugitive emissions component, as defined section I.6, for fugitive emissions.

(f) Each identified source of fugitive emissions shall be repaired or replaced in accordance with paragraphs (f)(1) and (2) of this section. For fugitive emissions components also subject to the repair provisions of sections A.4(d)(4) through (7) and D.2(e)(9) through (12), those provisions apply instead to those closed vent system and covers, and the repair provisions of paragraphs (f)(1) and (2) of this section do not apply to those closed vent systems and covers.

(1) Each identified source of fugitive emissions shall be repaired or replaced as soon as practicable, but no later than 30 calendar days after detection of the fugitive emissions.

(2) If the repair or replacement is technically infeasible, would require a vent blowdown, a gathering and boosting station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement must be completed during the next gathering and boosting station shutdown, well shutdown, well shut-in, after an unscheduled, planned or emergency vent blowdown or within 2 years, whichever is earlier.

(3) Each repaired or replaced fugitive emissions component must be resurveyed as soon as practical, but no later than 30 days after being repaired or replaced, to ensure that there are no fugitive emissions.

(i) For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, the operator may resurvey the repaired fugitive emissions components using EPA Method 21 or optical gas imaging within 30 days of being repaired.

(ii) For each repair or replacement that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph must be taken of that component or the component must be tagged for identification purposes. The digital photograph must include the date that the photograph was taken, must clearly identify the component by location within the site (*e.g.*, the latitude and longitude of the component or by other descriptive landmarks visible in the picture).

(iii) Operators that use EPA Method 21 to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (f)(3)(iii)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the EPA Method 21 instrument indicates a concentration of less than 500 ppm above background or when no soap bubbles are observed when the alternative screening procedures specified in section 8.3.3 of EPA Method 21 are used.

(B) Operators must use the EPA Method 21 monitoring requirements specified in paragraph (c)(8)(ii) of this section or the alternative screening procedures specified in section 8.3.3 of EPA Method 21.

(iv) Operators that use optical gas imaging to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (f)(3)(iv)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the optical gas imaging instrument shows no indication of visible emissions.

(B) Operators must use the optical gas imaging monitoring requirements specified in paragraph (c)(7) of this section.

(g) For each well with less than 300 scf of gas per stock tank barrel of oil produced, you must comply with paragraphs (g)(1) and (g)(2) of this section.

(1) You must determine the gas to oil ratio of your well using generally accepted methods.

(2) You must maintain the records specified in section I.5 (a)(4)

I.3 Initial Compliance Demonstration

To achieve initial compliance with the fugitive emission standards for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station, you must comply with paragraphs (a) through (e) or (f), if applicable, of this section.

(a) You must develop a fugitive emissions monitoring plan as required in sections I.2(b), (c), and (d).

(b) You must conduct an initial monitoring survey as required in paragraphs (b)(1) and (2), as applicable

(1) Each well site with a collection of fugitive emissions components must conduct an initial monitoring survey within 60 days of becoming subject to VOC emission control requirements of section I.

(2) Each gathering and boosting station with a collection of fugitive emissions components must conduct an initial monitoring survey within 60 days of being subject to VOC emission control requirements of section I.

(c) You must maintain the records specified in section I.5(a).

(d) You must repair or replace each identified source of fugitive emissions as required in section I.2(f).

(e) You must submit the initial annual report for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station as required in section I.5(b).

(f) You must determine the gas to oil ratio of your well using generally accepted methods and maintain the records specified in section I.5(a)(4).

I.4 Continuous Compliance Demonstration

For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station, you must demonstrate continuous compliance with the fugitive emission standards specified in section I.2 according to paragraphs (a) through (d) or (e), if applicable, of this section.

(a) You must conduct periodic monitoring surveys of each collection of fugitive emissions components at a well site and a gathering and boosting station subject to VOC emission control requirements under section I at the frequencies specified in paragraphs (a)(1) and (a)(2) of this section, with the exceptions noted in paragraphs (a)(3) through (a)(5) of this section.

(1) A monitoring survey of each collection of fugitive emissions components at a well site within a company-defined area must be conducted at least semiannually after the initial survey. Consecutive semiannual monitoring surveys must be conducted at least 4 months apart.

(2) A monitoring survey of the collection of fugitive emissions components at a gathering and boosting station within a company-defined area must be conducted at least quarterly after the initial survey. Consecutive quarterly monitoring surveys must be conducted at least 60 days apart.

(3) Fugitive emissions components that cannot be monitored without elevating the monitoring personnel more than 2 meters above the surface may be designated as difficult-to-monitor. Fugitive emissions components that are designated difficult-to-monitor must meet the specifications of paragraphs (a)(3)(i) through (iv) of this section.

(i) A written plan must be developed for all of the fugitive emissions components designated difficult-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by sections I.2(b), (c), and (d).

(ii) The plan must include the identification and location of each fugitive emissions component designated as difficult-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as difficult-to-monitor is difficult-to-monitor.

(iv) The plan must include a schedule for monitoring the difficult-to-monitor fugitive emissions components at least once per calendar year.

(4) Fugitive emissions components that cannot be monitored because monitoring personnel would be exposed to immediate danger while conducting a monitoring survey may be designated as unsafe-to-monitor. Fugitive emissions components that are designated unsafe-to-monitor must meet the specifications of paragraphs (a)(4)(i) through (iv) of this section.

(i) A written plan must be developed for all of the fugitive emissions components designated unsafe-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by sections I.2(b), (c), and (d).

(ii) The plan must include the identification and location of each fugitive emissions component designated as unsafe-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as unsafe-to-monitor is unsafe-to-monitor.

(iv) The plan must include a schedule for monitoring the fugitive emissions components designated as unsafe-to-monitor.

(5) The requirements of paragraph (a)(2) of this section are waived for any collection of fugitive emissions components at a gathering and boosting station located within an area that has an average calendar month temperature below 0°Fahrenheit for two of three consecutive calendar months of a quarterly monitoring period. The calendar month temperature average for each month within the quarterly monitoring period must be determined using historical monthly average temperatures over the previous three years as reported by a National Oceanic and Atmospheric Administration source or other source approved by the Administrator. The

requirements of paragraph (a)(2) of this section shall not be waived for two consecutive quarterly monitoring periods.

(b) You must repair or replace each identified source of fugitive emissions as required in section I.2(f).

(c) You must maintain the records specified in section I.5(a).

(d) You must submit annual reports for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station as required in section I.5(b).

(e) You must recalculate the gas to oil ratio of your well using generally accepted methods annually and maintain the records as required in section I.5(a)(4).

I.5 Recordkeeping and Reporting Requirements

(a) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station, the records identified in paragraphs (a)(1) through (3), and (a)(4), if applicable of this section shall be maintained onsite or at the nearest local field office for at least five years.

(1) The fugitive emissions monitoring plan as required in I.2(b), (c), and (d).

(2) The records of each monitoring survey as specified in paragraphs (a)(2)(i) through (ix) of this section.

(i) Date of the survey.

(ii) Beginning and end time of the survey.

(iii) Name of operator(s) performing survey. You must note the training and experience of the operator.

(iv) Monitoring instrument used.

(v) When optical gas imaging is used to perform the survey, one or more digital photographs or videos, captured from the optical gas imaging instrument used for conduct of monitoring, of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a gathering and boosting station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital file, the digital photograph or video may consist of an image of the monitoring survey being performed with a separately operating GPS device within the same digital picture or video, provided the latitude and longitude output of the GPS unit can be clearly read in the digital image.

(vi) Fugitive emissions component identification when EPA Method 21 is used to perform the monitoring survey.

(vii) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(viii) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(ix) Documentation of each fugitive emission, including the information specified in paragraphs (a)(2)(ix)(A) through (L) of this section.

(A) Location.

(B) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(C) Number and type of components for which fugitive emissions were detected.

(D) Number and type of difficult-to-monitor and unsafe-to-monitor fugitive emission components monitored.

(E) Instrument reading of each fugitive emissions component that requires repair when EPA Method 21 is used for monitoring.

(F) Number and type of fugitive emissions components that were not repaired as required in section I.2(f).

(G) Number and type of components that were tagged as a result of not being repaired during the monitoring survey when the fugitive emissions were initially found as required in section I.2(f)(3)(ii).

(H) If a fugitive emissions component is not tagged, a digital photograph or video of each fugitive emissions component that could not be repaired during the monitoring survey when the fugitive emissions were initially found as required in section I.2(f)(3)(ii). The digital photograph or video must clearly identify the location of the component that must be repaired. Any digital photograph or video required under this paragraph can also be used to meet the requirements under paragraph (a)(2)(v) of this section, as long as the photograph or video is taken with the optical gas imaging instrument, includes the date and the latitude and longitude are either imbedded or visible in the picture.

(I) Repair methods applied in each attempt to repair the fugitive emissions components.

(J) Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair.

(K) The date of successful repair of the fugitive emissions component.

(L) Instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

(3) For the collection of fugitive emissions components at a gathering and boosting station, if a monitoring survey is waived under section I.4(a)(5), you must maintain records of the average calendar month temperature, including the source of the information, for each calendar month of the quarterly monitoring period for which the monitoring survey was waived.

(4) For the collection of fugitive emissions at a well site with a gas to oil ratio of less than 300 scf per stock barrel of oil produced, you must maintain:

(A) A record of the gas to oil ratio analyses documenting a gas to oil ratio of less than 300 scf per stock barrel of oil produced, conducted pursuant to sections I.3(f) and I.4(e).

(B) The location of the well and the United States Well ID Number.

(C) A record of the determination signed by the certifying official. The claim must include a certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

(b) Annual reports shall be submitted for the collection of fugitive emissions components at each well site and the collection of fugitive emissions components at each gathering and boosting station within the company-defined area, that are subject to VOC emission control requirements under section I. Each annual report shall include the records of each monitoring survey including the information specified in paragraphs (b)(1) through (12) of this section. For the collection of fugitive emissions components at a gathering and boosting station, if a monitoring survey is waived under section I.4(a)(5), you must include in your annual report the fact that a monitoring survey was waived and the calendar months that make up the quarterly monitoring period for which the monitoring survey was waived. Multiple collection of fugitive emissions components at a well site or collection of fugitive emissions as a gathering and boosting station subject to VOC emission control requirements under section I may be included in a single annual report.

(1) Date of the survey.

(2) Beginning and end time of the survey.

(3) Name of operator(s) performing survey. If the survey is performed by optical gas imaging, you must note the training and experience of the operator.

(4) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(5) Monitoring instrument used.

(6) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(7) Number and type of components for which fugitive emissions were detected.

(8) Number and type of fugitive emissions components that were not repaired as required in section I.2(f).

(9) Number and type of difficult-to-monitor and unsafe-to-monitor fugitive emission components monitored.

(10) The date of successful repair of the fugitive emissions component.

(11) Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair.

(12) Type of instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

I.6 Definitions

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding \$25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including, but not limited to, general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.*, a Regional Administrator of EPA); or

(4) For facilities subject to requirements:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Gathering and boosting station means any permanent combination of one or more compressors that collects natural gas from well sites and moves the natural gas at increased pressure into gathering pipelines to the natural gas processing plant or into the pipeline. The combination of one or more compressors located at a well site, or located at an onshore natural gas processing plant, is not a gathering and boosting station for purposes of this section.

Gas to oil ratio (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

Intermediate hydrocarbon liquid means any naturally occurring, unrefined petroleum liquid.

Flow line means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.

Fugitive emissions component means any component that has the potential to emit fugitive emissions of VOC at a well site or gathering and boosting station including, but not limited to, valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to section A.2(c) or (d) or section D, thief hatches or other openings on a controlled storage vessel not subject to section A, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For purposes of the fugitive emissions standards at section I.1, well site also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (*e.g.*, centralized tank batteries).

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

United States
Environmental Protection
Agency

Office of Air Quality Planning and Standards
Sector Policies and Programs Division
Research Triangle Park, NC

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MEMORANDUM

DATE: June 9, 2005

SUBJECT: Cost per Ton for NSPS for Stationary CI ICE

FROM: Tanya Parise, Alpha-Gamma Technologies, Inc.

TO: Sims Roy, EPA OAQPS ESD Combustion Group

The purpose of this memorandum is to estimate the cost per ton of pollutant removed for the proposed new source performance standards (NSPS) for stationary compression ignition (CI) internal combustion engines (ICE). This memorandum also presents the cost per ton of other control technologies EPA considered.

Introduction

The proposed rule requires stationary CI engines to comply with standards that have been promulgated for nonroad CI engines. These standards consist of various tiered levels that increase in stringency. Although the proposed rule requires stationary CI engines to meet all tiers, EPA expects that stationary CI engines would generally emit the same levels as nonroad engines until Tier 4 is required, even in the absence of the rule. For the purpose of estimating reductions for stationary CI engines, the EPA does not take credit for reductions until Tier 4 is in effect. This means that the baseline level for estimating reductions is the tier level prior to Tier 4. The EPA expects that nitrogen oxides (NO_x) adsorbers and catalyzed diesel particulate filters (CDPF) will be used to meet Tier 4 levels and are expected to reduce NO_x and particulate matter (PM) emissions, respectively, by at least 90 percent.

Control Cost

The methodology for estimating the cost of these control technologies is presented in the memorandum entitled "Control Costs for NO_x adsorbers and CDPF for CI Engines," included in the docket (Docket ID No. OAR-2005-0029). The average annual cost of control for NO_x adsorbers and CDPF were each estimated at \$1 per horsepower (HP). The combined annual cost of control was estimated at \$2/HP. To determine the annual control cost per engine, EPA multiplied the combined annual cost

of control by the average engine size for each HP range. The total annual cost of control per engine for each engine size range is presented in Table 1.

Table 1. Annual Cost of Control per Engine
w/NO_x Adsorbers and CDPF

HP Range	Average HP	Annual Control Cost (\$/HP)	Annual Control Cost per Engine (\$/yr)
50-75	63	2	126
75-100	88	2	176
100-175	135	2	270
175-300	238	2	476
300-600	450	2	900
600-750	675	2	1,350
750-1,200	975	2	1,950
1,200-3,000	2,100	2	4,200
>3,000	5,000	2	10,000

Emission Reduction

The emission factors corresponding to the various tiers were obtained from Table A.2 of EPA's emission factors for nonroad CI engine modeling.¹ To determine the pollutant reduction per engine as a result of applying Tier 4 add-on control, EPA subtracted the Tier 4 level from the previous tier level. The resulting emission factors representing the reduction per engine for each size range are shown in Table 2.

Table 2. Emission Factors for NO_x and PM

¹US EPA. Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling—Compression Ignition. EPA420-P-04-009. April 2004. NR-009c.

HP Range	Emission Factor (g/HP-hr)					
	NO _x			PM		
	Previous Tier	Tier 4*	Reduction	Previous Tier	Tier 4**	Reduction
50-75***	3.0	0.30	2.700	0.20	0.0184	0.1816
75-100	3.0	0.276	2.724	0.30	0.0092	0.2908
100-175	2.5	0.276	2.224	0.22	0.0092	0.2108
175-300	2.5	0.276	2.224	0.15	0.0092	0.1408
300-600	2.5	0.276	2.224	0.15	0.0092	0.1408
600-750	2.5	0.276	2.224	0.15	0.0092	0.1408
750-1,200	2.392	0.46	1.932	0.069	0.0184	0.0506
1,200-3,000	4.1	0.46	3.640	0.069	0.0184	0.0506
>3,000	4.1	0.46	3.640	0.069	0.0184	0.0506

*Tier 4 for NO_x is based on the use NO_x adsorbers.

**Tier 4 for PM is based on the use of CDPF.

***NO_x add-on control is not required for this size range. Estimates shown are for information purposes only, assuming a hypothetical 90 percent reduction of NO_x from the previous tier.

Using the emission reduction per engine shown in Table 2, the yearly emission reduction per engine for each HP range was calculated using the following equation:

$$\frac{\text{Reduction} \left(\frac{g}{\text{HP-hr}} \right) \times \text{Average HP} \times \frac{\text{hrs}}{\text{yr}} \times 0.0022046 \frac{\text{lb}}{g}}{2,000 \frac{\text{lb}}{\text{ton}}}$$

where:

Reduction = The reduction of NO_x or PM per engine for each HP range, in g/HP-hr, from Table 2,
Average HP = Average engine size for each HP range, from Table 1,
hrs/yr = Average hours of operation (1,000 hrs/yr for prime engines; 37 hrs/yr for emergency engines),
0.0022046 = Conversion factor, in lb/g, and
2,000 = Conversion factor, in ton/lb.

Based on the above equation and the emission factors representing the reduction per

engine in Table 2, EPA estimated the reductions per engine per year presented in Table 3.

Table 3. Estimated Reduction of NO_x and PM per Engine
w/NO_x Adsorbers and CDPF

HP Range	Reduction per Engine (tpy)			
	NO _x		PM	
	Prime	Emergency	Prime	Emergency
50-75*	0.188	0.007	0.0126	0.0005
75-100	0.264	0.010	0.0282	0.0010
100-175	0.331	0.012	0.0314	0.0012
175-300	0.583	0.022	0.0369	0.0014
300-600	1.103	0.041	0.0698	0.0026
600-750	1.655	0.061	0.1048	0.0039
750-1,200	2.076	0.077	0.0544	0.0020
1,200-3,000	8.426	0.312	0.1171	0.0043
>3,000	20.062	0.742	0.2789	0.0103

*NO_x add-on control is not required for this size range. Estimates shown are for information purposes only and are based on a hypothetical 90 percent reduction of NO_x from the previous tier.

Cost per ton

Based on the annual cost of control per engine shown in Table 1 and the reduction per engine shown in Table 3, EPA estimated the cost of control per ton of pollutant removed as shown in Table 4.

Table 4. Cost of Control per Ton of Pollutant Removed
w/NO_x Adsorbers and CDPF

HP Range	Cost per ton NO _x Removed (\$/ton)		Cost per ton PM Removed (\$/ton)		Cost per ton NO _x +PM Removed (\$/ton)	
	Prime	Emergency	Prime	Emergency	Prime	Emergency
50-75*	672	18,162	4,996	135,015	630	17,017
75-100	666	18,002	6,239	168,630	602	16,266
100-175	816	22,049	8,607	232,626	745	20,140
175-300	816	22,049	12,886	348,278	767	20,736

HP Range	Cost per ton NO _x Removed (\$/ton)		Cost per ton PM Removed (\$/ton)		Cost per ton NO _x +PM Removed (\$/ton)	
	Prime	Emergency	Prime	Emergency	Prime	Emergency
300-600	816	22,049	12,866	348,278	767	20,736
600-750	816	22,049	12,866	348,278	767	20,736
750-1,200	939	25,382	35,857	969,121	915	24,734
1,200-3,000	498	13,472	35,857	969,121	492	13,287
>3,000	498	13,472	35,857	969,121	492	13,287

*NO_x add-on control is not required for this size range. Estimates shown are for information purposes only and are based on a hypothetical 90 percent reduction of NO_x from the previous tier.

The EPA also evaluated the cost per ton of using selective catalytic reduction (SCR). The NO_x reduction using SCR is expected to be the same as NO_x adsorber, i.e., about 90 percent, so the EPA used the NO_x reduction shown in Table 3 to estimate the cost per ton with SCR. Based on information received from control technology vendors, EPA estimated SCR annual control costs of \$36/HP per engine. The resulting costs per ton of NO_x removed for various stationary CI engine sizes are shown in Table 5.

Table 5. Cost of Control per Ton of NO_x Removed w/SCR

HP Range	SCR Annual Control Cost per Engine (\$/yr)	NO _x Reduction per Engine		Cost per ton NO _x Removed (\$/ton)	
		Prime	Emergency	Prime	Emergency
50-75	2,268	0.188	0.007	12,096	326,917
75-100	3,168	0.264	0.010	11,989	324,036
100-175	4,860	0.331	0.012	14,685	396,886
175-300	8,568	0.583	0.022	14,685	396,886
300-600	16,200	1.103	0.041	14,685	396,886
600-750	24,300	1.655	0.061	14,685	396,886
750-1,200	35,100	2.076	0.077	16,904	456,871
1,200-3,000	75,600	8.426	0.312	8,972	242,493

HP Range	SCR Annual Control Cost per Engine (\$/yr)	NO _x Reduction per Engine		Cost per ton NO _x Removed (\$/ton)	
		Prime	Emergency	Prime	Emergency
>3,000	180,000	20.062	0.742	8,972	242,493

Finally, EPA evaluated the cost per ton of using oxidation catalyst. The technology can reduce PM emissions up to 30 percent from stationary CI engines. Based on information obtained from the Office of Transportation and Air Quality for oxidation catalysts, EPA developed oxidation control costs following the methodology discussed in the control cost memorandum referenced earlier in this memorandum. Using that methodology, EPA estimated an average annual cost of control for oxidation catalysts of \$0.30/HP per engine. Assuming oxidation catalysts will reduce PM emissions by 30 percent from stationary CI engines, EPA estimated the cost per ton of PM removed for various stationary CI engine sizes as shown in Table 6.

Table 6. Cost of Control per Ton of PM Removed
w/Oxidation Catalyst

HP Range	Oxidation Catalyst Annual Control Cost per Engine (\$/yr)	PM Reduction per Engine		Cost per ton PM Removed (\$/ton)	
		Prime	Emergency	Prime	Emergency
50-75	19	0.004	0.0002	4,536	122,594
75-100	26	0.009	0.0003	3,024	81,729
100-175	41	0.010	0.0004	4,124	111,449
175-300	71	0.012	0.0004	6,048	163,458
300-600	135	0.022	0.0008	6,048	163,458
600-750	203	0.033	0.0012	6,048	163,458
750-1,200	293	0.022	0.0008	13,148	355,344
1,200-3,000	630	0.048	0.0018	13,148	355,344
>3,000	1,500	0.114	0.0042	13,148	355,344

RESEARCH ARTICLE

Equipment leak detection and quantification at 67 oil and gas sites in the Western United States

Adam P. Pacsi*, Tom Ferrara†, Kailin Schwan†, Paul Tupper‡, Miriam Lev-On§, Reid Smith|| and Karin Ritter¶

Emissions from equipment leaks from process components, such as valves and flanges, were measured at 67 sites in the oil and natural gas production and gathering and boosting segments in four different onshore production basins in the western United States. Component counts were obtained from 65 of the 67 sites where nearly 84,000 monitored components resulted in a leak detection rate of 0.39% when detection results using both optical gas imaging (OGI) and a handheld flame ionization detector (FID) were combined. OGI techniques identified fewer leaks but greater total emissions than surveys using an FID operated in accordance with United States Environmental Protection Agency (EPA) Reference Method 21. Many of the leaks that were identified only with an FID were on the lower end of the emission rate distribution in this study. Conversely, OGI identified several components on the higher end of the study emission rate distribution that were not identified with FID-based methods. The most common EPA estimation method for greenhouse gas emission reporting for equipment leaks, which is based on major site equipment counts and population-average component emission factors, would have overestimated equipment leak emissions by 22% to 36% for the sites surveyed in this study as compared to direct measurements of leaking components because of a lower frequency of leaking components in this work than during the field surveys conducted more than 20 years ago to develop the current EPA factors. Results from this study further support emerging evidence that methane detection technologies for oil and gas applications should be evaluated on a different framework than a simple comparison of the counts of leaks detected.

Keywords: Methane emissions; Oil and gas; Fugitives; Optical gas imaging

Introduction

Recent studies have utilized a variety of on-site and off-site measurement methods to characterize regional and site-level methane emissions from oil and gas infrastructure in the United States (US), including techniques such as direct measurement of individual sources (e.g. Allen et al., 2013; Kuo et al., 2015; Thoma et al., 2017), ground-based mobile surveys (e.g. Brantley et al., 2014; Robertson et al., 2017) and regional box-model flights (e.g. Schwietzke et al., 2017). In addition to the development of equipment or component-specific emission factors for inventory development, studies with on-site, direct measurements are important for informing off-site measurement approaches by identifying the actual sources of emissions

(Vaughn et al., 2017), although some variation in site-level emission rate estimates would be expected when comparing off-site and on-site measurement approaches (Bell et al., 2017). Direct measurements can also be used to constrain possible source-specific emission rates for emission inventory development studies that use statistical distributions of emission rates rather than average emission factors to characterize regional emissions from the oil and gas sector (e.g. Zavala-Araiza et al., 2015; Allen et al., 2017).

For the onshore oil and gas production and gathering and boosting segments in the US EPA Greenhouse Gas Reporting Program (GHGRP), the most commonly-used emission estimation approach for equipment leak emissions (US EPA, 2017b) is based on a count of major equipment at the basin-level (e.g. number of separators) by operator, default component count estimates per piece of major equipment (e.g. number of valves per separator), and a default component average, or population, emission factor (e.g. standard cubic feet per hour [scfh] per valve). For 2017 reporting under the GHGRP, a second type of emission estimation method was available for the first time for sites that undertook a qualifying leak detection and repair (LDAR) survey and was based on a count of identified leaking components and a default emission

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factor per leaking component, or leaker emission factor, (e.g. scfh per leaking valve). Both population and leaker emission factors for GHGRP reporting are based on a study (Hummel et al., 1996) that used field measurement data (API, 1993) from more than 20 years ago, which may not be representative of current equipment leak emissions in the oil and natural gas industry due to changes in equipment design, operation, and monitoring since the completion of that former work.

A previous direct measurement study (Allen et al., 2013) conducted measurements of leaking components at 150 new gas well sites throughout the US. Based on a national extrapolation of the study data, Allen et al. (2013) estimated that equipment leaks were higher than the value that was reported in the US Greenhouse Gas Inventory (GHGI) for 2011. The Allen et al. (2013) study did not collect component count metadata that would be necessary to make comparisons to current GHGRP emission estimation approaches, and the previous study utilized a single approach, OGI, for identifying leaking components on well sites.

Modeling approaches (Kemp et al., 2016; Ravikumar et al., 2017; Ravikumar et al., 2018) have been developed to assess the effectiveness of different leak detection technologies for identifying leaking components on oil and gas sites. These studies have typically utilized distributions of the magnitude and frequency of equipment leaks compiled from direct measurement studies (e.g. Allen et al., 2013) to estimate the emission reduction potential of LDAR programs. Additional information on the magnitude and frequency of leaking components should help to improve such models and can serve as an independent validation of the appropriateness of model assumptions with respect to the effectiveness of different leak detection methods, such as OGI and FID, using side-by-side comparison data between methods under actual field and survey conditions.

This study focuses on direct measurement of equipment leaks from oil and natural gas production and gathering and boosting sites in the western US based on GHGRP geographic definitions. Equipment leaks are emissions from on-site piping and equipment components, such as valves and flanges. Equipment leaks accounted for more than 40% of industry-reported methane emissions from the US onshore production and gathering and boosting segments in 2016 (US EPA, 2017a) as part of the GHGRP. In addition, identification of leaking components is a typical feature of voluntary and regulatory LDAR programs. Such programs may include the use of optical gas imaging (OGI), handheld flame ionization detector (FID), and audio, visual, and olfactory (AVO) techniques to distinguish leaking components from those operating as designed. Previous studies have noted that emissions from other equipment on oil and gas sites, such as tanks (Lyon et al., 2016) or malfunctioning pneumatic controllers (Thoma et al., 2017), may be present and detectable with similar tools on some oil and gas sites. This paper, however, focuses on one category of emissions, equipment leaks, and does not characterize emissions from other potential oil and gas sources.

The purpose of this study is to compare existing EPA default emission and component count factors used in the GHGRP for the Western US to equipment leak emissions observed at oil and gas sites. The study also seeks to compare the in-field side-by-side results of actual OGI and FID-based surveys for upstream oil and gas sites, which has not yet been studied and reported in the peer-reviewed literature to date.

Materials and methods

Basin and site selection

Equipment leak surveys and quantification measurements were conducted between June 2015 and December 2015 in four basins, as defined by the American Association of Petroleum Geologists (AAPG): Permian (AAPG Basin 430), Anadarko (AAPG Basin 360), Gulf Coast (AAPG Basin 220 that includes the Eagle Ford shale), and San Juan (AAPG Basin 580). Based on 2016 GHGRP data (US EPA, 2017c), operators in these four basins accounted for 47.2% of the total reported methane emissions from equipment leaks in the production and gathering and boosting segments. These four basins were also the top four basins nationally for reported equipment leaks, as shown in the Supporting Information (SI) Figure S1. Within these basins, eight companies volunteered sites for this study. No metadata was collected as part of this study to understand the fraction of production or well-counts represented by these volunteer companies.

Before the measurement team arrived on site, each participant company provided a list of assets in the basin, which were classified into four facility categories based on the types of major equipment, as defined in 40 CFR 98 Subpart W Table W-1B and Table W-1C, located on the site: well site, well production, central production, and gathering and boosting, as outlined in Table S1. While these four facility categories are not related to GHGRP reporting terminology, they were used to ensure that sites selected for this study had a variety of major equipment and levels of hydrocarbon processing. Before arriving in the basin, the GHD Services Incorporated (GHD) field team selected measurement sites from the asset list and communicated the selections (typically 5 primary sites and 5 back-up sites, in case the primary sites were not accessible) to the company field office approximately two weeks before sampling occurred so that arrangements could be made to provide operational support for those sites. Attempts were made to select sites from the range of facility categories that were present in the company's assets in the basin. Some sites that were selected were geographically clustered to minimize the driving time between sites and maximize the number of measurements that could be undertaken while the GHD team was in the field.

Onsite detection and measurement methods

For each site, FID and OGI-based equipment leak detection surveys were conducted independently by different trained GHD field technicians to minimize the bias in leak determination between the two methods. Typically, the OGI survey was started while the FID was being calibrated, and the OGI technician noted the location of leaks but did

not identify the leaks until after the FID-based survey was completed in the same area of the facility. OGI was conducted with a FLIR Model GF-320 infrared (IR) camera, as outlined in 40 CFR §60.18 (g) work practice for identifying fugitive emissions. Both conventional and high sensitivity modes on the FLIR Model GF-320 camera were used, based on the experience of the trained camera operator.

FID-based surveys were conducted with a Thermo Scientific TVA-1000B that was calibrated with methane following procedures outlined in 40 CFR 60 Appendix A, Method 21. For the FID-based surveys, the probe was moved around the seal surface of each component until the maximum concentration value was located, and any maximum concentration reading that exceeded 500 parts per million (ppm) for a component was tagged and designated for additional quantification measurements. With FID-based approaches, different ppm thresholds can be used to designate a component that is leaking and designated for repair from a component with a screening value below the repair threshold for the program. Unless otherwise stated in this work, a 500-ppm leak threshold was used to take a conservative approach to leak identification. Additional details on instrument calibration and field procedures are outlined in the SI.

For each leak that was identified by OGI or FID, the emission rate of whole gas was quantified using a high-volume sampler. Briefly, measurements with this technique involve vacuum-sampling from a nozzle or bag loosely fitted over the emission source. The sample consists of the gas from the leak and any ambient air drawn into the enclosure in which the combustible gas concentration is measured with either a catalytic oxidation (0–5% hydrocarbon gas) or a thermal conductivity (5–100% hydrocarbon gas) detector. The combination of gas concentration and sample flow measurements are used to compute the gas emission rate. Details on high-volume sampler operation are available in the SI and references such as Lamb et al. (2015) and Thoma et al. (2017). In this study, both the commercial Bacharach high volume sampler and a custom Indaco high volume sampler were used for leak measurements. Whole gas emission rates were determined by adjusting the measured combustible gas concentration by the high-volume sampler response to site-specific gas compositions, which were provided by the participant companies based on their most recent gas analysis for the site. This was intended to follow protocols that companies would use for greenhouse gas emission reporting, which do not include compositional analysis for each leak or process stream on a site. Instrument-specific response factors to methane, ethane, propane, and butane were developed by GHD and are outlined in the SI. If the site gas composition was not available, the average gas composition from other sites in this study in the same AAPG basin was used. The average instrument response factor used in this study was 1.028, which varied based on the site gas composition and the high-volume sampler or back-up detector that was used for the concentration measurement used in the emission calculation.

During the field work for this study, a leak was discovered at a cracked fitting on a glycol pump for a

dehydration system. This leak was identified by sound and a buildup of ice on the system piping. The presence of gas in the area surrounding the leak, which exceeded the lower explosion limit (LEL) action level, required the crew to stay away from the leak, and the source was determined to be unsafe to quantify. Since this emission source would have been identified and quickly repaired by operations personnel during any site visit due to the audible and visual evidence for the emission source as shown in Figure S4, the estimated emissions from the source are not included in the study estimates for equipment leak emissions that focused on components, such as valves and flanges. Additional descriptions of the source and upper bound emission calculations are presented in the SI.

Recent concerns have been raised in the literature (Howard, 2015; Howard, et al., 2015) about the performance of Bacharach high-volume sampler during field campaigns at oil and natural gas production sites. For this study, an augmented protocol was utilized to ensure that the instrument was performing accurately and transitioning properly between the two measurement modes on the device. The augmented protocol included at least daily calibration and the use of a secondary hydrocarbon detector in the high-volume sampler exhaust to verify the accuracy of the hydrocarbon sensors and transition between catalytic and thermal conductivity mode. More information on the augmented high-volume sampler protocol is available in the SI.

In addition to collecting information on the number of leaking components and their associated emissions for each site, the GHD field team also conducted an actual component count (i.e. number of valves, flanges, etc.) and assigned each component to a major piece of equipment (i.e. wellhead, separator, etc.). A database with study component counts, component count assignments to on-site equipment, and information on leaking components is available as described in the Data Accessibility Statement. The study team did not collect metadata information on the existence of voluntary or regulatory LDAR programs at the sites.

Sampled population

Component count surveys were conducted at a total of 65 sites (41 gas and 24 oil, as defined by the site operator) with 83,960 components inventoried. Leak detection surveys were conducted at 67 sites with OGI and at 65 sites with FID. For two sites (GHD0011 and GHD0012), an FID-based detection survey was not conducted due to time constraints for the GHD field team. Hydrocarbon leaks were identified, by one or both methods, and measured at 52 sites. No leaks were identified at 15 of 67 sites surveyed with OGI, and no leaks were identified at 13 of 65 sites with the FID. The surveyed population of components at the 65 sites included connectors (70%), flanges (15%), valves (14%), open-ended lines (OEL) (1%), and pressure relief valves (PRV) (1%), including components in both gas (75%) and oil (25%) service. More information on the classification of sites included in each of the four basins is available in Table S2.

Results and discussions

Leaks detected and method comparisons

For the 67 sites in this study and 83,960 total components screened, a total of 331 components were identified as leaking during on-site leak detection surveys by either visual identification with OGI, an FID screening value of 500 ppm or greater, or both methods. The population of leaking components in this study had whole gas emission rates that ranged from 0.006 scfh to 83.6 scfh. The study average whole gas emission rate per leaking component was much higher (4.4 scfh) than the median (0.3 scfh), suggesting that the distribution of leaks was skewed, and the top 10% of individual leaking components accounted for 73% of the measured emissions in the study. As shown in Table S6, connectors (flanged and threaded) and valves represented 62% and 16%, respectively, of the total leaks detected by any emission survey method.

Summary statistics shown in Table S7 for the leaking components identified at the 67 sites indicate that leaks detected in oil and gas service had similar emission characteristics. For the 65 sites in this study which had component counts, a higher percentage of components in gas service (0.49%) were identified as leaking than components in oil service (0.11%). These two findings suggest that leaking components identified in oil service were similar to leaking components identified in gas service, but a smaller fraction of components in oil service had emission rates that reached a detection threshold for OGI or FID-based surveys.

In this study, OGI and FID-based surveys for equipment leaks identified different populations of leaking components. The two methods overlapped identification for 23% of the total count of leaking components and 56% of the total emissions from identified components. As shown in **Figure 1** for sites with both survey methods present, OGI

identified 33% of leaking components while FID-based survey methods identified 90% of leaking components when utilizing a 500-ppm leak definition threshold. However, after quantification measurements were completed on each of the components that were identified as leaking by either method, OGI identified similar overall emissions (80%) to the FID-based survey (79%) at a 500-ppm threshold for sites on which both survey methods were conducted. The comparison between OGI and FID-based surveys was broadly consistent with a previous report (Concawe, 2015) that compared the performance of these types of devices on the leak detection methods in oil refinery applications.

The distribution of leaking component emission rates identified in this study is shown in **Figure 2**. Among the 17 components in the top 5% of leaks in the study, 4 were identified uniquely by OGI, and these components represented 14% of total emissions measured in the study. By contrast, 67% of measured leaks had emission rates of less than 1 scfh, and most of these leaks (83%) were identified uniquely by the FID survey using a 500-ppm threshold for leak definition. Emissions from these 184 components, however, only accounted for 3.3% of the total emissions from leaking components that were measured in the study. Summary statistics shown in Table S8 indicate that OGI and FID-based detection methods may be identifying different populations of components as leaking. For all monitored components in oil and gas service, respectively, OGI identified a smaller percentage of leaking components (0.02% and 0.17%) than FID-based methods (0.11% and 0.43%) across the sites in this study with a component count.

The types of leaks identified in this work by OGI and FID-based leak detection methods indicates that FID-based approaches may identify more leaking components

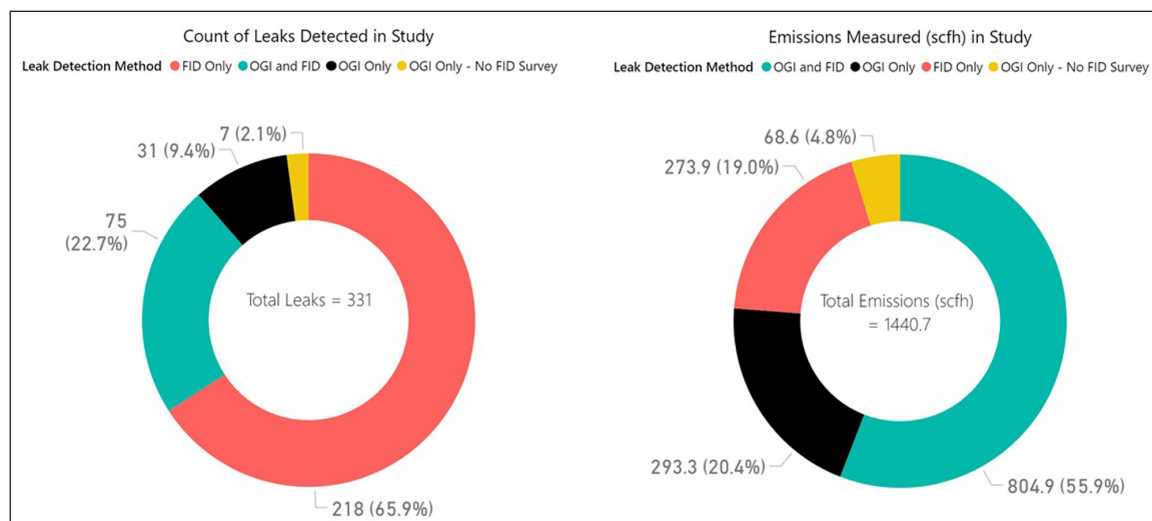


Figure 1: Comparison of the count and emission rate of equipment leaks detected by OGI and FID-based surveys. Figure 1 shows the number (left) and emission rate (right) of equipment leak emissions detected in the field campaign using optical gas imaging (OGI), flame ionization detection (FID) following EPA Method 21 with a 500 parts per million (ppm) threshold, or both detection methods. Results indicate that the FID-based surveys identified a larger count of leaks but that OGI-based surveys detected a similar percentage of overall emissions. Emissions and leak counts labeled in yellow were from two sites where only OGI emission surveys were undertaken. DOI: <https://doi.org/10.1525/elementa.368.f1>

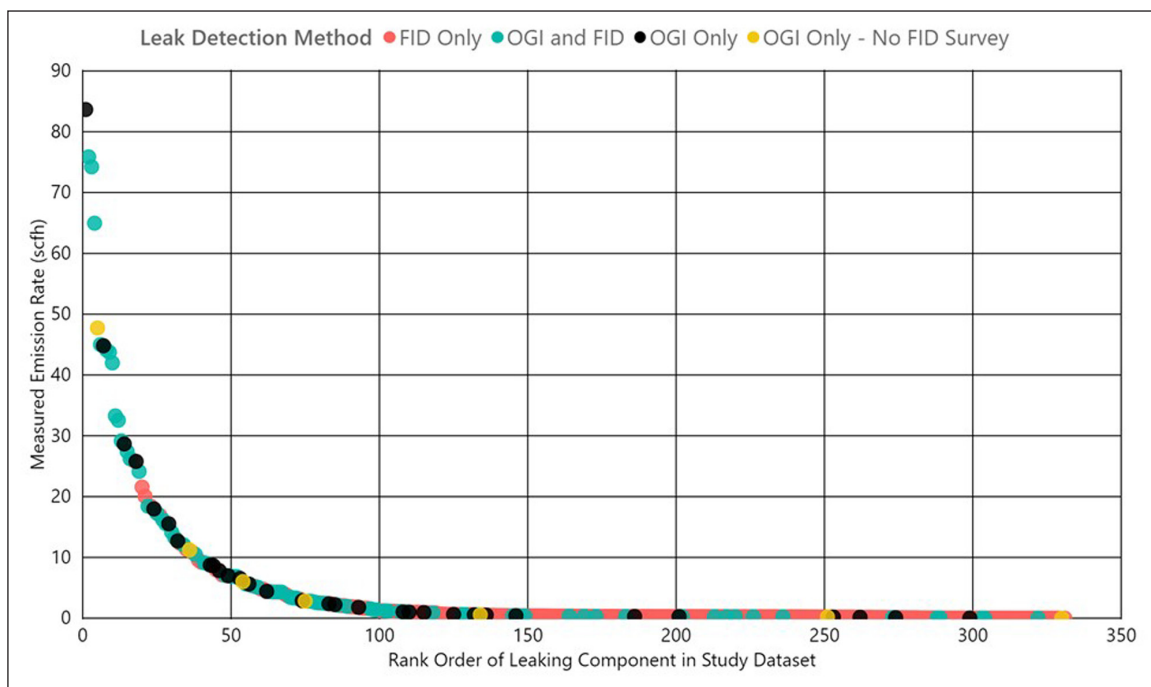


Figure 2: Distribution of equipment leaks detected by OGI and FID-based surveys in this study. Figure 2 shows the emission rate in standard cubic feet per hour (scfh) that was measured with the high-volume sampler for each leak identified by one or both emission detection methods. Leaking components identified only by OGI techniques tended to be higher on the overall distribution of measured equipment leaks in the study while those identified uniquely by FID surveys tended to be lower in emission magnitude. DOI: <https://doi.org/10.1525/elementa.368.f2>

overall, but many of the additional leaks detected with an FID will have emission rates on the lower end of the leak distribution that may not, in aggregate, constitute a significant percentage of total equipment leak emissions from a site. Conversely, OGI-based surveys may uniquely identify some leaking components that are on the upper-end of the overall leaking component distribution and may have a larger emission reduction potential upon repair than the lower volume leaks that were identified with FID-based methods alone.

There are several potential explanations for identification of leaks with OGI and not with FID. Since OGI surveys are broader in scope than component-specific FID surveys, OGI may identify emissions from components that are not included in FID surveys or from elevated locations on a site. In addition, the relative geometry of a leak location and the FID probe location at the component may, at times, involve sufficient dispersion such that the FID reading falls below a repair threshold for the program. This study was designed to compare the performance of the two leak screening methods under real field conditions and not to fully assess the differences as to why certain leaks were detected or not by individual methods.

Different LDAR programs have established a range of thresholds for which an FID reading is considered a leak that should be designated for repair. Comparisons of FID-based survey results are presented in **Figure 3** on a leak count and emission basis, relative to the performance of OGI for the leaks identified in this study. For this study, regardless of the leak definition threshold (between 500 and 10,000 ppm) that is selected for the FID-based survey, leaking components identified by FID readings were

always greater in count but lower in cumulative emissions than leaking components identified by OGI. This suggests that the FID and OGI-based surveys conducted in this work identified fundamentally different populations of leaking components and that it would be difficult to establish a simple ppm leak definition threshold that implied equivalency between the two methods.

Number of leaks identified per site in surveys

In order to understand the effectiveness of different leak detection methods, information on the number of leaking components per site with different leak detection approaches is important for modeling the cost effectiveness of different LDAR program options and in informing models (Kemp et al., 2016; Ravikumar et al., 2017; Ravikumar et al., 2018) that estimate the frequency and size of different types of fugitive emission sources, including equipment leaks, at oil and gas sites in the US.

On average for the sites that were surveyed in this study, OGI and FID-based survey methods using a 500-ppm threshold identified 1.7 and 4.5 leaks per site, respectively. As shown in **Figure 1**, OGI surveys identified a higher volume of emissions from site equipment leaks. The number of leaking components identified per site with OGI in this study (1.7) is comparable to previous emission detection surveys conducted with OGI as part of the Allen et al. (2013) study, which found 1.9 leaks per site. Notably, the distribution of leaks detected per site with OGI is also a skewed distribution, which is a commonly-observed feature from direct measurement studies of oil and gas production sources (e.g. Allen et al., 2015). As shown in Figure S5, 45% of sites did not have any leaking components

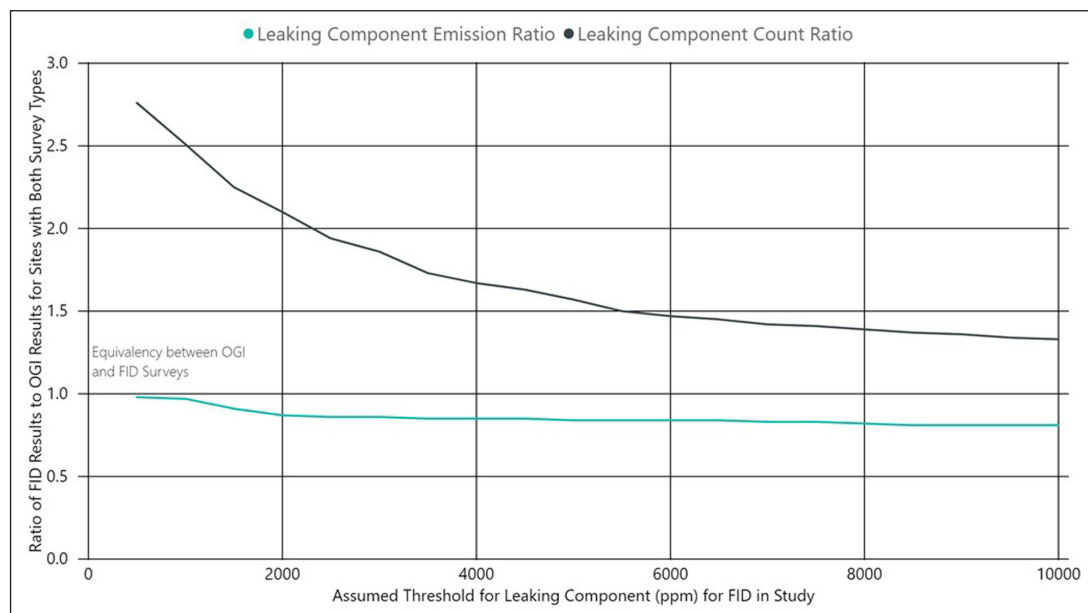


Figure 3: Ratio of leak count and emissions for different FID-based leak definition thresholds compared to OGI. Figure 3 displays, for the 50 sites with measured leaks and both survey techniques, the ratio of the count of leaking components as well as the associated emissions by FID-based surveys that would have been identified, relative to those identified with OGI, based on the range of leak detection definitions in parts per million (ppm) that are commonly-adopted for LDAR programs. Results show that OGI surveys for the sites identified greater emissions but less total leaks than FID-based surveys with different leak threshold definitions. DOI: <https://doi.org/10.1525/elementa.368.f3>

identified by OGI while 7% of total sites accounted for 42% of the total leaks identified by OGI. A weak correlation ($R^2 = 0.41$) was observed between the component count at a site and the number of leaking components identified on that site by OGI, as shown in Figure S6. This suggests that additional factors besides site size influenced the number of leaking components present during the study leak detection surveys in this work.

Comparison to current EPA emission estimation approaches

In the United States, the most common equipment leak emission estimation method in the GHGRP involves population-average emission factors for components and default average component counts by major equipment. Due to the location of the four basins in this study, all comparisons in this work were to default values for the western United States rather than the eastern United States (US EPA, 2017b) for gas and light oil services. Note that some components identified as leaking, such as pressure regulators, did not have an exact match to components outlined in GHGRP reporting. The emissions from these sources, however, are included in site-level emission estimates developed in this study.

Figure 4 and Table S9 compare site-level emission estimates for equipment leaks based on major equipment counts and the actual measured emissions from all identified leaking components at the site level. For the 65 sites in the study for which a component count was completed, major equipment count-based estimates (**Figure 4**) would have predicted aggregate equipment leak emissions of 2241 scfh; however, direct measurements of all identified leaking components from FID and OGI-based surveys

indicate that actual emissions from equipment leaks were 36% lower with total emissions of 1433 scfh. As a sensitivity analysis, each leaking component at the 65 sites was randomly assigned an emission rate value from the study leak distribution. Over 1000 trials, the 95% interval for the measured equipment leak emissions ranged between 1127 scfh and 1780 scfh, and none of the trials exceeded the value from application of major equipment counts and GHGRP factors for the 65 sites.

As shown in **Figure 4**, there is some variation on an individual site basis with 11 sites (17% of the sites in the study sample) exceeding the emission estimate from major equipment count-based approaches when all major equipment on site is counted. Most sites (54 of 65) had measured equipment leak emissions below those predicted by methods based on site-level major equipment counts. The two sites that had leak detection surveys and quantification but no major equipment or component counts had measured total equipment leak emissions of 7.3 scfh and 0.6 scfh. Having a component count for those sites would not be expected to significantly affect the results of this study.

Analysis of average population emission factors per component surveyed (Table S10) and component counts (Table S11) gives insight into a likely explanation that equipment leak emissions that were measured in this study are lower than would have been predicted by the most common emission estimation method used in the GHGRP. Over the 65 sites in the study, the total number of components counted was 55% higher (Table S11) than would have been predicted with default EPA component count estimates. Component count estimates per major equipment are also presented in Table S12 and show

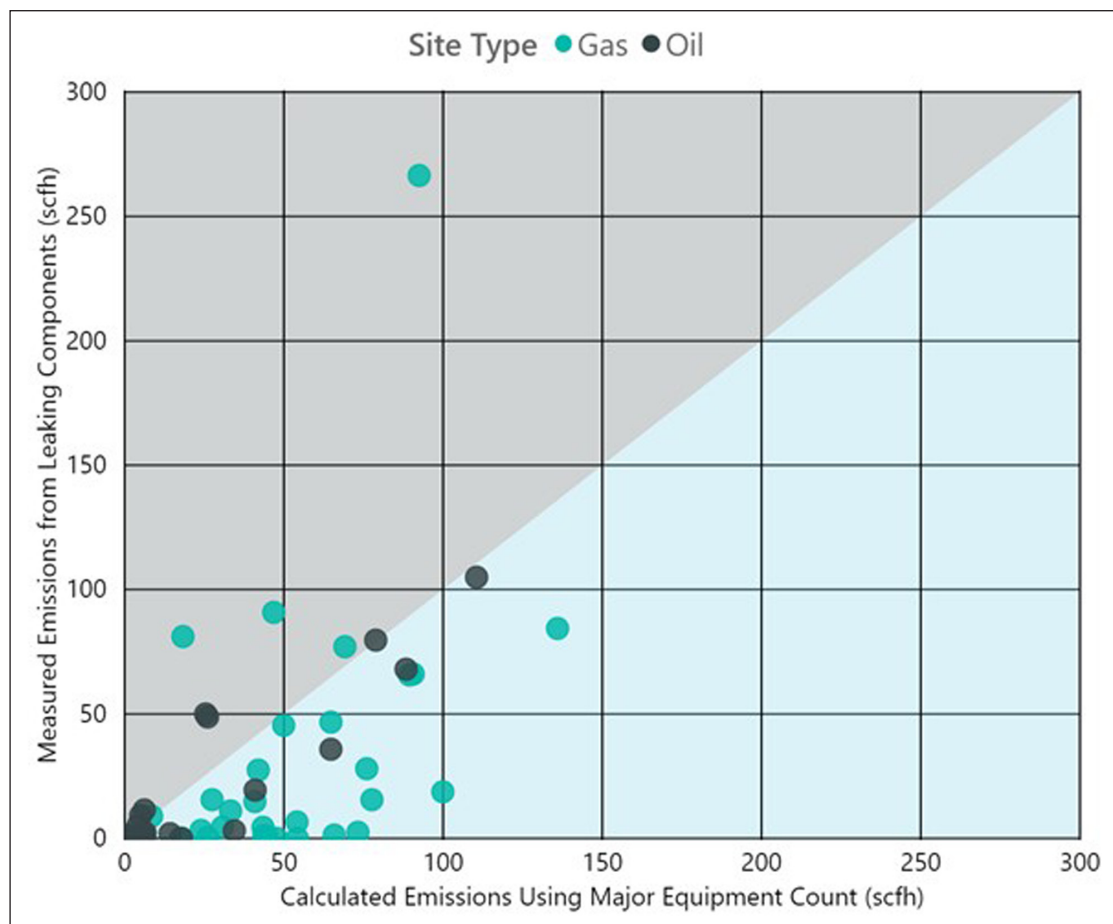


Figure 4: Comparison of site-level measured emission rates from field campaign to default EPA estimation approaches. Figure 4 compares measured equipment leaks from identified leaking components at sites surveyed in this study to a default major equipment count-based approach that is typically utilized for industry-reported emissions data under the GHGRP. The gray area indicates site-level equipment leak emissions where measured emissions exceeded estimates, while the blue area indicates sites for which the default approach would have overestimated emissions. Calculated emissions are based on site major equipment counts and population-average emission factors for components. Overall measured emissions were 36% lower across all sites than would have been predicted from using EPA's major equipment count methodology. DOI: <https://doi.org/10.1525/elementa.368.f4>

a similar trend to aggregate components from across all sites in the study. EPA leaker emission factors in the GHGRP, by contrast, are lower than those developed from data in this study (Tables S13 and S14), especially for components in gas service. For the 331 leaking components identified in this study, the total measured emissions were 1441 scfh compared to an estimate of 859 scfh that would have been calculated with current EPA leaker emission factors in the GHGRP for leaking components in oil and gas services. Furthermore, the population-average emissions factors per component (Table S10) in this study, except for OELs in gas service, were much lower than values in the default EPA emission factors. As shown in Table S13 for gas service, the leaker emission factors from this study are lower in magnitude than previous EPA analysis (EPA, 2016) of data from Allen et al. (2013) and the Fort Worth Air Quality Study (City of Fort Worth, 2011).

A sensitivity analysis was conducted using emission factors (EPA, 1995) for non-leaking components in light oil and gas service. Non-leaking components would add an estimated 48.9 scfh (3.4%) to the equipment leak measurements from the study that were made on components

identified as leaking. This impact would likely be an upper bound since the emission factors were developed for components with an FID screening value of less than 10,000 ppm, while this study measured all components with a screening value of 500 ppm or greater. Inclusion of emissions from the non-leaking components does not explain the observed difference between the results of this study and current estimates from GHGRP methodologies.

In this study, leaking components occurred less frequently than leaking components in the previous study (Hummel et al., 1996) on which current EPA equipment leak emission factors are based. The Hummel et al. (1996) study is based on a prior American Petroleum Institute (API) publication (API, 1995) that published total component and leaking component counts based on FID surveys that identified 'emitters' (10–9,999 ppm) and 'leakers' ($\geq 10,000$ ppm) at a total of 24 industry sites including four light crude and four gas production sites with 48,652 and 32,534 screened components, respectively. In the prior API study, 0.67% of components at onshore crude production sites and 1.61% of components at gas production sites had an FID screening value that

was 10,000 ppm or greater. More broadly, 1.77% of all screened components at the eight oil and gas production sites had an FID reading greater than or equal to 500 ppm. By contrast, only 0.17% and 0.35% of components screened in this study had an FID reading that exceeded 10,000 ppm and 500 ppm, respectively, and 0.39% of components overall were identified as leaking with OGI or an FID reading exceeding 500 ppm (Table S15). This study, however, was not designed to understand the extent to which factors, such as existing LDAR programs, improved facility design, or differences in emission detection technology deployment, may be driving this lower frequency of observed leaking components. Similarly, a California study of equipment leaks at natural gas sites (Kuo et al., 2015) identified 378 leaking gas service components (over a 100 ppm leak threshold), or 0.47% of the 80,423 non-welded components screened, which is similar, but not directly comparable to the results of this study since components in that work spanned the natural gas value chain from production through distribution and also had an initial leak screening method that differed from the methods used in this study.

Study uncertainty

While direct measurement studies are important to understand potential emission rates associated with certain types of equipment on oil and gas sites, there are several sources of uncertainty for this study. As noted in Allen et al. (2013), direct measurement study sample sizes tend to be small relative to the national population of sources. For example, there are more than one million active oil and gas wells (U.S. EPA 2017a) in the United States, and the 67 sites in this study would compose a small fraction of overall sites. While the study team attempted to gather data from a variety of site types, this study does not claim national representativeness in the study results. Other sources of uncertainty include the measurement techniques, the representativeness of single emission snapshots at the visited facilities, and the statistics around the underlying skewed distribution for the emission sources measured in this work. Quantifying values for such uncertainty is beyond the scope of this study. It should be noted that the study (Hummel et al., 1996) that underlies current emission factors in the US would have similar questions around uncertainty. In addition, this study was not designed to understand the extent to which factors, such as prior LDAR surveys on the sites, improved facility design, or differences in emission detection technology deployment, may explain differences in emission estimates from this study compared to current US emission factors.

Comparison to other direct measurement studies

The most appropriate comparisons of equipment leak measurements in this study are previously-published studies that provide disaggregated information for leaking components since this study did not make measurements on other on-site sources, such as tanks or liquid unloading, that would be necessary to compare results to studies that report site-level emissions (e.g. Bell et al., 2017).

In **Figure 5**, a comparison is made between the equipment leaks that were identified with OGI in this field campaign to measured equipment leaks from the Allen et al. (2013) study. That study also employed OGI-based approaches to identify leaking components and the emission rate from all identified leaking components were quantified. Other studies that have been used in numerical simulations of fugitive emissions (Kemp et al. 2016) were not selected for comparison since they typically relied on FID-based identification approaches for identification of leaking components, which, as shown in **Figures 2 and 3**, likely leads to an identification of a fundamentally different set of leaking components than OGI, which is the most common method used in industry LDAR surveys at oil and gas sites in the United States. In addition, several other field studies were not selected for comparison since they involved different instrumentation for leak identification (Kuo et al., 2015) and since the leak detection survey only included a subset of the components at each site (City of Fort Worth, 2011).

In general, the distribution of equipment leaks identified in this study by OGI had higher emissions per leaking component than the equivalent percentile of leaks identified in Allen et al. (2013), except for the two highest emitting components in that 2013 field campaign, as shown in **Figure 5**. The largest two emission sources that were identified in the Allen et al. (2013) field campaign were both located in the Appalachian region in the northeastern United States, which is not one of the four basins where measurements were made in this study. As a result, a sensitivity analysis is also shown in **Figure 5** that compares the percentiles of leaking components identified with OGI in this study with only data sets in the Midcontinent, Gulf Coast, and Rocky Mountain regions from the Allen et al. (2013) study. Comparing the regionally consistent data sets between the two studies, the maximum measured individual leaking component had a similar order of magnitude [78 scfh in Allen et al. (2013) and 84 scfh in this study], but the average emission per leaking component identified by OGI is larger in this study (10.3 scfh) than that previous field campaign (4.7 scfh).

High-volume sampler measurement

Results from this field campaign indicate the importance of using the augmented protocol with a secondary verification instrument in the high-volume sampler exhaust. In this study, the GHD field team noted six instances in which the Bacharach high-volume sampler failed to transition between measurement modes, and all instances occurred on sites with less than 90% methane content in the sales gas, as suggested by Brantley et al. (2015). These six measurements represent 2.1% of overall equipment leak measurements in the study with the Bacharach high volume sampler and 2.4% of equipment leak measurements with the Bacharach high volume sampler in the study on sites with less than 90% methane content in the provided gas composition. For these six measurements, the average emission rate increased by 10.3 scfh per leaking component with the use of the hydrocarbon concentration from the Heath DPIR backup detector. If the uncorrected

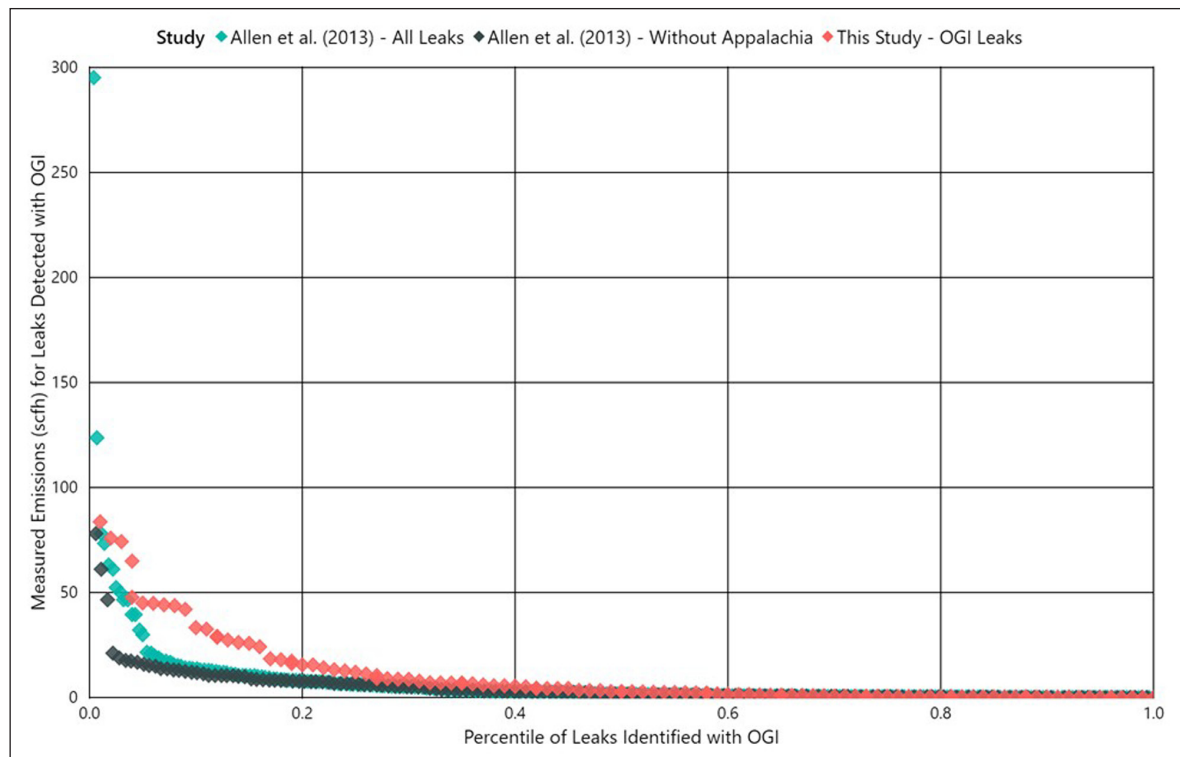


Figure 5: Comparison of equipment leak emissions to previous direct measurement study. Figure 5 compares the distribution of measured emissions in this study from components that were identified with optical gas imaging (OGI) to a previous field campaign (Allen et al., 2013) that utilized a similar in-field procedure to identify leaking components. Emission rates of components that were identified as leaking with OGI in this study were typically larger than the equivalent percentile of leaking components in the Allen et al. (2013) study except for the largest two emission sources from the Allen study, which were greater than 100 scfh and were both located in the Appalachian region. Since the Appalachian region was not included in this study, a sensitivity analysis was conducted to compare Allen et al. (2013) measurements in similar regions to the measurements in this study. DOI: <https://doi.org/10.1525/elementa.368.f5>

high-volume sampler concentration reading for those six measurements would have been utilized, overall emissions from equipment leaks in the study would have been 1379 scfh, or 4.3% less than the 1441 scfh estimated from all leaking components measured in this study.

This result shows that high-volume sampler transition failures can occur within upstream direct measurement studies and that unaccounted emissions can be a notable fraction of overall equipment leaks as posited in previous work (Howard, 2015; Howard, et al., 2015). For this study, the effect of this phenomenon was not sufficient to fundamentally change the order of magnitude for equipment leak emissions, which agreed with a previous modeling-based assessment (Alvarez et al. 2016). It should be noted that firmware and calibration schedule on the high-volume sampler that was used in this study was different than those used in the studies noted by Howard (2015).

From a post-field campaign laboratory characterization of the response factors for several different models of hydrocarbon detectors that could be used as backup instruments for these types of measurements, it was also noted that some backup devices may have elevated response to higher molecular weight hydrocarbons in field gas, such as propane. Thus, the response factors of the high-volume sampler and the back-up instrument

must be well-characterized to develop accurate emission rates from field high-volume sampler measurements.

There is an additional source of uncertainty in this study related to the use of instrument response factors to account for the differential response of the concentration measurements used in this study for emission rate quantification. For a sensitivity analysis, emissions from all measured components in the study were estimated without the application of response factors. Under this sensitivity analysis, total emissions would have been 1768 scfh, which is 23% greater than the total study emissions with the application of the correction factors for the measurements. For sites with a major equipment count available (Figure S4), total emissions without the response factor applied (1761 scfh) would still be 22% less than emissions estimated based on GHGRP major equipment count methods for those sites (2241 scfh).

Conclusions

Results of a field campaign to conduct direct measurements of emissions from equipment leaks at oil and gas production and gathering and boosting sites in four producing basins in the western United States indicate that the current default emission estimation approach for this source category (US EPA, 2017b), which is based on major equipment counts, would have overestimated detected

and measured emissions from leaking components at these 65 sites by 22% to 36%, depending on the handling of instrument response factors. This difference was driven by a lower fraction of leaking components identified in this study compared to the data set on which current EPA emission estimation approaches in the GHGRP are based. Using a 10,000 ppm leak definition threshold for FID-based methods, this study identified 0.18% of components at gas sites and 0.15% of components at oil sites as leaking, while the previous study (API, 1995) had identified 1.61% of components at gas sites and 0.67% of components at oil sites as leaking.

Results from this study also indicate that the two most prominent identification methods for leaking components, FID and OGI, identified different populations of leaking components under field conditions in this study, but the two methods had similar performance based on total emissions identified across all sites in this study, even with an FID leak detection threshold of 500 ppm. This emissions equivalency occurred despite the total count of leaks identified by OGI being only 36% of the total count of leaks identified with FID-based methods. This result suggests a need for emerging methane detection technologies to be evaluated on a different framework than a comparison of the counts of leaks detected. Emission detection equivalency may be achieved through a variety of different approaches that could include considerations related to both the number of detections, the volume of emissions, and the duration over which the leaks would have likely occurred. Such conclusions are consistent with previous modeling (Kemp et al., 2016) and field study results (Schwietzke et al., 2018) comparing different methane emission detection strategies.

Data Accessibility Statement

Datasets produced in this work are available online, free-of-charge, as part of supplement material.

Supplemental files

The supplemental files for this article can be found as follows:

- **Text S1.** Includes 13 tables, six figures, and supporting text for the manuscript, as described throughout the text. DOI: <https://doi.org/10.1525/elementa.368.s1>
- **Database S2.** Includes a study component counts, component count assignments to on-site equipment, and information on leaking components. DOI: <https://doi.org/10.1525/elementa.368.s2>

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Competing interests

The authors declare the following competing financial interest(s):

- APP is a current employee of Chevron U.S.A. Inc., and previously worked on methane emission research projects that were supported by multiple natural gas producers and the Environmental Defense Fund.
- TF and KF are consultants with GHD Services, Inc. and are currently involved in measuring methane emissions in a variety of projects across the natural gas supply chain. These projects have been funded by API, the Environmental Defense Fund, US Department of Energy, and several oil and gas operators and gas utilities.
- PT is a current employee of Shell Global Solutions (US) Inc.
- MLO and GRS have provided consulting services to API and other customers in the areas of greenhouse gas emissions quantification and reporting, methane losses from oil and gas operations and linkages between energy sources and emissions. GRS previously worked for BP in the areas of greenhouse gas management, climate policy and air quality.
- KR is an employee of API's Regulatory and Scientific Affairs and manages API's regulatory response to various government initiatives.

Author contributions

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- Contributed to conception and design: AP, TF, MLO, RS, KR, PT
- Contributed to acquisition of data: TF, KS
- Contributed to analysis and interpretation of data: AP, TF, KS, MLO, RS, PT
- Drafted and/or revised the article: AP, TF, KS, MLO, RS, KR, PT
- Approved the submitted version for publication: AP, TF, KS, MLO, RS, KR, PT

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Characterizing Light-Off Behavior and Species-Resolved Conversion Efficiencies During In-Situ Diesel Oxidation Catalyst Degreening

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Characterizing Light-Off Behavior and Species-Resolved Conversion Efficiencies During In-Situ Diesel Oxidation Catalyst Degreening

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ABSTRACT

Degreening is crucial in obtaining a stable catalyst prior to assessing its performance characteristics. This paper characterizes the light-off behavior and conversion efficiency of a Diesel Oxidation Catalyst (DOC) during the degreening process. A platinum DOC is degreened for 16 hours in the presence of actual diesel engine exhaust at 650°C and 10% water (H₂O) concentration. The DOC's activity for carbon monoxide (CO) and for total hydrocarbons (THC) conversion is checked at 0, 1, 2, 3, 4, 6, 8, 10, 12, and 16 hours of degreening. Pre- and post-catalyst hydrocarbon species are analyzed via gas chromatography at 0, 4, 8, and 16 hours of degreening. It is found that both light-off temperature and species-resolved conversion efficiencies change rapidly during the first 8 hours of degreening and then stabilize to a large degree. T₅₀, the temperature where the catalyst is 50% active towards a particular species, increases by 14°C for CO and by 11°C for THC through the degreening process. The shapes of the conversion versus DOC inlet temperature curves are preserved. With respect to species-resolved hydrocarbons, conversion efficiency is always highest for acetylenes, followed by olefins, aromatics, non-methane paraffins, and methane.

INTRODUCTION

With ever more stringent emissions standards, DOC's are being used in the abatement of hydrocarbon, carbon monoxide and the soluble organic fraction (SOF) of particulate matter (PM) from diesel exhaust since the early 1990's [1, 2]. In addition to the application as clean-up catalysts, DOC's are also being used as heating-devices in active regeneration of diesel particulate filters (DPF) or lean NO_x traps (LNT) [3, 4, 5, and 6].

Nitric oxide (NO_x) emissions, however, are generally not reduced by the DOC. Measures to reduce engine-out NO_x and PM, such as homogeneous charge compression ignition (HCCI) or premixed compression ignition (PCI) strategies, tend to increase CO and hydrocarbon emissions [7]. Additionally, improvements in the fuel efficiency of the diesel engine tend to reduce exhaust gas temperatures, which impose great challenges to traditional diesel oxidation aftertreatment devices [1].

While DOC's may have very attractive performance characteristics when brand new, their activity deteriorates over time. Many researchers have studied catalyst decay and conditions leading to such [8, 9, 10, 11, 12, 16 and 17]. The most common causes for catalyst decay are thermal deactivation, poisoning, fouling, attrition and mechanical failure [3, 4, 13, and 14]. Exposure to high temperature in the presence of water vapor causes thermal deactivation due to sintering of precious metal sites. The initially highly dispersed precious metal atoms coalesce into larger agglomerates. In its most severe form, thermal deactivation causes phase transformation of the washcoat, thus reducing the specific surface area and eventually eroding the supporting monolith. Poisoning is the deactivation of the catalyst by chemical reactions of the catalytically active material with species present in the feedgas. Fouling or masking in turn is the mechanical deposition of material onto the catalyst which blocks access to the catalytic sites. While poisoning is a discriminating process, i.e. only specific species are affected, fouling is a non-discriminating process. Finally, attrition is a mechanical phenomenon in which catalytic surface area is lost due to abrasive forces such as high fluid velocities or mechanical break-away.

Some of the catalyst deactivation may be reversible and the catalyst can regain activity with proper treatment. It has been shown that coking, a form of fouling, for example, may be reversible by heat-treatment of the catalyst [1]. Washing a catalyst in alkaline solutions has proven to be effective in removing phosphorous from the catalyst and restoring its activity [8]. Thermal deactivation, however, is an irreversible process [8].

It has been shown that catalyst activity deteriorates severely in the first few hours of operation when exposed to high temperatures [5, 12, and 15]. This effect is even more pronounced in the presence of water vapor [16]. It is thought that thermal deactivation due to sintering causes the very rapid initial catalyst decay. When catalysts are studied, it is therefore necessary to degreen the fresh catalysts, i.e. stabilize catalytic activity prior to assessing the DOC performance. Degreening can be either performed hydrothermally (in an oven in the presence of water vapor) or in-situ in an engine test-cell. In-situ degreening more closely reflects what a catalyst actually experiences in the field and is therefore preferred.

While several studies have been published exploring the long-term (500-1000 hrs) performance characteristics of DOC, relatively less emphasis has been placed on exploring the initial degreening process. Therefore the goal of the present study is to investigate the effect of in-situ thermal degreening on DOC performance and the effects on hydrocarbon species conversion during the degreening process. Starting with a green catalyst and monitoring its characteristics at regular operating intervals, we can realistically assess both the length of time required to reach stable operation, as well as the expected light-off activity and performance of the degreened DOC.

EXPERIMENTAL SETUP

All tests are run in an engine – dynamometer test cell. The engine is a 1.7 liter high-speed diesel engine (HSDI) equipped with a common rail fuel injection system, variable geometry turbo charger (VGT), cooled exhaust gas recirculation (EGR) and an intake throttle. The compression ratio of the engine is 16:1. Engine specifications are listed in Table 1. Low-sulfur Swedish diesel fuel is used in this study to avoid possible sulfur poisoning of the catalyst. Fuel properties for Swedish low-sulfur and 2005 US#2 diesel are given in Table 2.

Degreening Setup

Figure 1 shows the catalyst setup for degreening. First the engine exhaust is passed through a heating DOC, and then through a clean-up catalyst and finally into the DOC to be degreened. Exhaust gas temperatures are measured before and after each catalyst. Standard emissions are analyzed before and after each catalyst with an AVL CEBII emissions bench. The entire catalyst setup is wrapped in 25 mm thick fiberglass insulation to

reduce heat loss. When the oxidation catalyst is tested for activity, the heating DOC and the clean-up catalyst are removed, and the DOC is mounted approximately 1 m downstream of the turbine outlet, at the location where the heating DOC is shown in Figure 1.

Oxidation Catalyst Specifications

A model catalyst with 400 cells per square inch (CPSI), a volume of 1.24 Liters, an alumina washcoat, and 7.7 g/ft³ platinum (Pt) loading is used in this study. This lightly loaded catalyst formulation is chosen to better control and characterize the light-off behavior. The monolith measures 144 mm in diameter and 76.2 mm in length. A stainless steel housing is used to support the monolith. Temperature and exhaust gas samples are taken 120 mm upstream and 120 mm downstream of the DOC. The catalyst bed temperature is measured 25 mm from the front face of the substrate.

Table 1: Engine specifications

Engine Type	Diesel Engine
Number of Cylinders	4
Displacement (L)	1.7
Compression Ratio	16.0:1
Valves / Cylinder	4
Number of Cams	2
Fuel System	Common Rail Direct-Injection
Turbocharger	VGT
EGR Valve	Poppet-style Control Valve
Intake Throttle	Flapper Style

Table 2: Diesel fuel properties

	Swedish Diesel	US Diesel #2
Cetane Number	51.6	49.6
Sulfur Cont. (ppm wt.)	12	500
LHV (MJ/kg)	43.48	42.91
AFR Stoichiometric	14.74	14.46
Density (kg/m ³)	810	840
T50 (°C)*	224	257
Molecular C:H:O ratio	C ₁ H _{1.966} O _{0.000}	C ₁ H _{1.771} O _{0.000}

* Temperature at which 50% of the fuel is vaporized

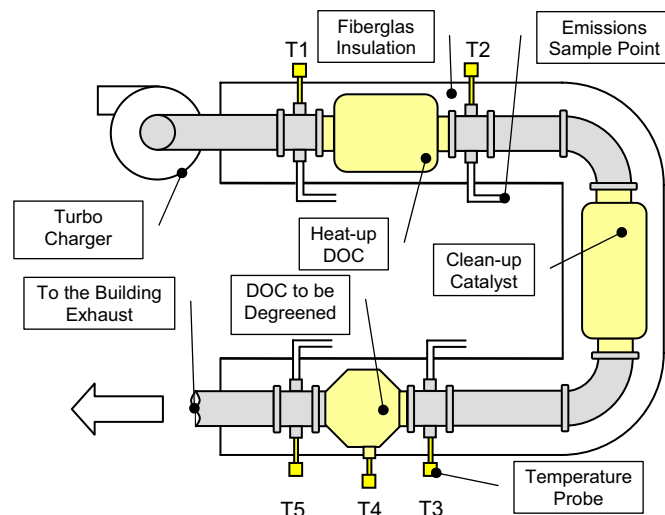


Figure 1: Degreening setup

Hydrocarbon Speciation

Hydrocarbon speciation via gas chromatography (GC) techniques has been successfully developed for gasoline [21, 22, and 23] and more recently for diesel engine exhaust [24, 25, and 26]. Diesel hydrocarbon speciation is more challenging because exhaust hydrocarbons span a much larger range of carbon numbers (C_1 - C_{22+}) and properties.

An exhaust sample cart and a two-GC system were designed to perform diesel exhaust sampling and speciation in this study. The sample cart uses a micro-pump to draw raw exhaust from before or after the DOC; semi-volatile hydrocarbons are adsorbed onto a hydrocarbon trap and light hydrocarbons pass through the trap and are diluted with nitrogen in a sample bag.

The sample bag captures light hydrocarbons (C_1 - C_8) and the Tenax trap captures semi-volatile hydrocarbons ($>C_8$), although an overlap of about 2 carbon numbers exists for each. One GC is used to analyze the sample bag (GC-1) while another GC is used to analyze the Tenax trap (GC-2). Both GCs are Shimadzu GC-17A models with flame ionization detectors (FIDs) that are used to measure hydrocarbon carbon atoms (ppmC₁).

Results from GC-1 and GC-2 are combined to obtain an overall speciation of exhaust hydrocarbons. This method yields more than 210 hydrocarbon species and identifies roughly 70% of carbon mass. More detail on the HC speciation technique can be found elsewhere [28].

RESULTS AND DISCUSSION

DEGREENING PROCEDURE

The fresh (green) DOC is degreened for 16 hours total in the presence of actual diesel engine exhaust. After every hour of degreening the activity of the DOC is checked, which will be discussed later. For degreening, 650°C exhaust gas temperature, 10% H₂O concentration and no HC and CO in the feedgas are specified as target values that the DOC is exposed to. Removing CO and HC from the feedgas avoids localized exothermic reactions in the degreening catalyst. Furthermore, low sulfur and HC concentrations in the exhaust prevent poisoning and masking, thus thermal aging is the sole process deactivating the catalyst. The engine is run at moderate speed and load of 1500 rpm and 600 kPa BMEP with conventional diesel combustion strategy. To raise the exhaust gas temperature, fuel is injected into the cylinder at a crank angle of 90° after top dead center (°ATDC). Little of the chemical energy introduced by the post injection is released; instead, it leaves the cylinder in the form of unburned or partially reacted hydrocarbons and CO. Thus, the exhaust gas temperature downstream of the turbine is about 350°C and large amounts of HC and CO are present as shown in Figure 2 – 4.

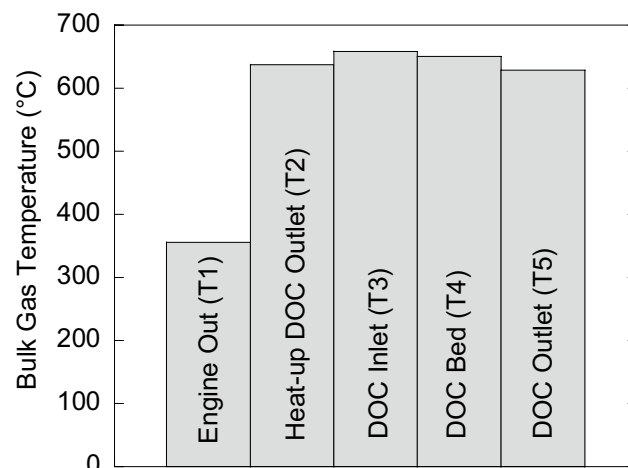


Figure 2: Representative exhaust gas temperatures at various sample locations during degreening

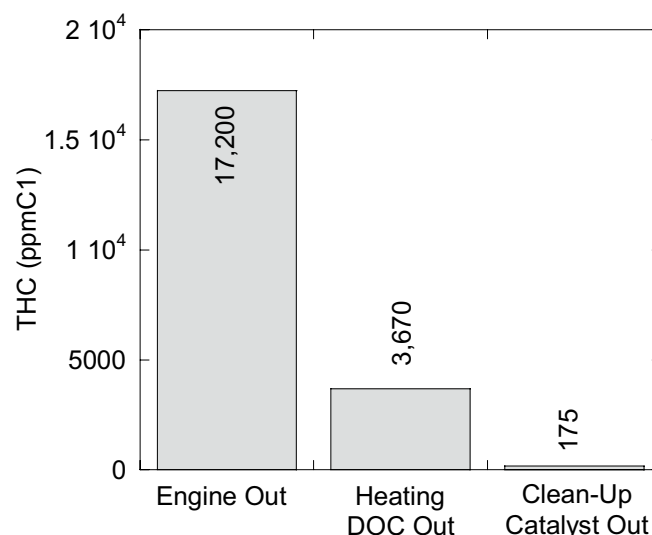


Figure 3: THC concentrations in the exhaust: engine out, heating DOC out, and clean-up catalyst out

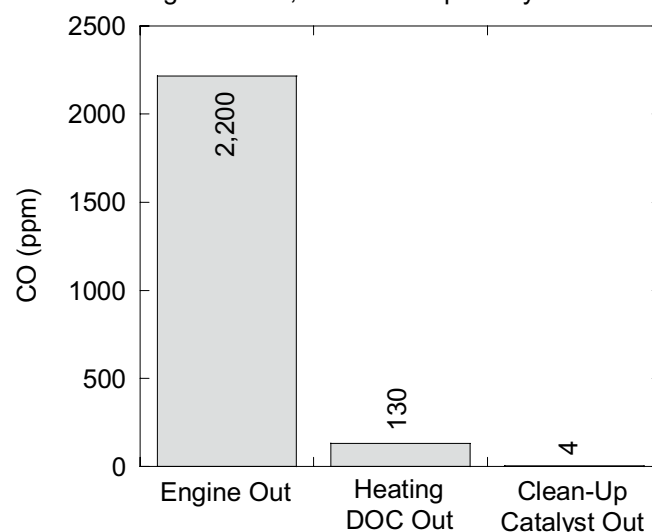


Figure 4: CO concentrations in the exhaust: engine out, heating catalyst out, and clean-up catalyst out

Through the heat-up catalyst, the exhaust gas temperature is increased to about 640°C, and much of the HC and CO is converted to H₂O and CO₂. Even though the proper degreening temperature can be achieved by the heat-up DOC, CO (130 ppm) and particularly THC (3,670 ppmC₁) levels are too high. A clean-up catalyst is therefore placed downstream of the heat-up catalyst as shown in Figure 1. This catalyst, a conventional three-way catalyst (TWC), oxidizes the remaining CO to below 5 ppm and lowers the HC levels to less than 200 ppmC₁ as shown in Figure 3 and Figure 4. Many of the hydrocarbons entering the degreening DOC are found to be methane, which is difficult to oxidize. Besides oxidizing the remaining CO and HC, the clean-up catalyst raises the exhaust gas temperature to the required 650°C.

ACTIVITY CHECK PROCEDURE

Catalyst activity strongly depends on the temperature, and light-off or light-down generally occurs over a very narrow temperature window. To check activity, the engine is run at a particular speed and load at which the DOC is fully lit and conversion efficiencies of CO and THC are determined by analyzing exhaust gas before and after the DOC. Next, the fueling of the engine is reduced, thus reducing exhaust gas temperature. After stabilizing the engine for 5 minutes, exhaust constituents are analyzed pre and post DOC. Repeating this procedure with decreasing loads eventually fully lights-down the catalyst and a quasi-steady state light-down curve is acquired. Examples of such curves for CO and THC are shown in Figure 5. In this case, starting at a nominal engine operating condition of 1500 rpm and 262 kPa BMEP, the fueling is decreased step-wise to reduce the DOC inlet temperature from 250°C to 200°C, which corresponds to 170 kPa BMEP at the same engine speed.

Figure 5 reveals that the catalyst performance depends upon whether the catalytic reaction is undergoing light-off or light-down. The hysteresis between light-off and light-down on Pt is largely attributed to self-inhibition by CO [18 and 19]. At low temperatures, CO strongly chemisorbs to the Pt-sites and thus deactivates the catalyst. As the temperature increases, CO desorbs and the precious metal sites become accessible to O₂, which then removes even more CO by oxidizing it to CO₂. The precious metal sites are now accessible to hydrocarbon species and they are starting to be converted as well. When the catalyst is fully lit, the catalytic surface is

covered with oxygen and CO-inhibition does not occur until lower temperatures. From here on, light-down curves are shown but one must bear in mind that light-off occurs at slightly higher temperatures for this particular catalyst.

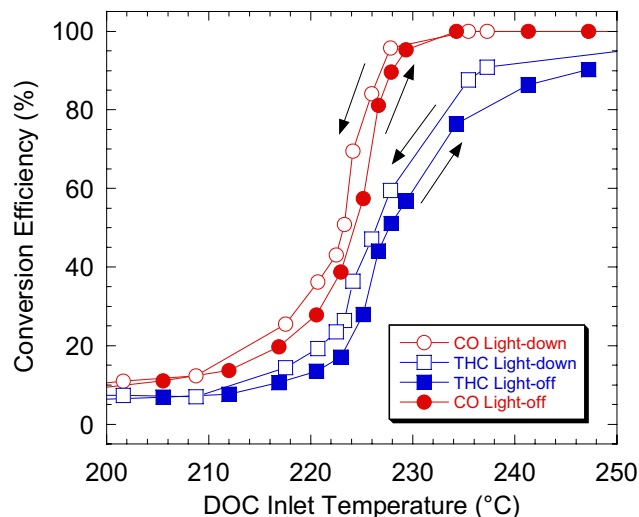


Figure 5: Light-off and light-down curves versus temperature (T3) for CO and THC at M2, 1500 rpm / 262 kPa BMEP nominal

Light-down characteristics of the oxidation catalyst are examined at three engine operating conditions (modes). Table 3 lists the main characteristics for the 3 modes. When the fueling is reduced at any of the nominal engine operating modes, not only does the temperature at the DOC inlet change, but other metrics are affected as well. Changes in SV are shown in Figure 6. When the engine load and the exhaust gas temperature decrease, the space velocity generally decreases as well. However, there are instances where SV increases when engine load decreases. This may be due to the engine control strategy, e.g. changes in the VGT, EGR and injection timing that affect the throughput of the engine.

CO and THC feedgas concentrations are affected when engine load is varied as shown in Figure 7. Both CO and THC concentrations increase when the engine load, and thus the exhaust gas temperature, is decreased. THC increases by 50 – 100%, while CO increases by 0 – 60%. Catalyst light-down can thus not solely be attributed to temperature; SV and species concentration affect the catalyst performance as well.

Table 3: Engine operating conditions and corresponding DOC inlet conditions

Mode	Speed (rpm)	Load	Load (kPa)	SV (hr ⁻¹)	AFR	CO (ppm)	THC (ppmC ₁)	H ₂ O (%)	O ₂ (%)	NO _x (ppm)	FSN (-)	DOC Inlet Temp. (°C)
M2	1500	High	300	50,000	37	650	300	5	13	160	1.5	260
		Low	160	40,000	50	500	500	3.5	16	70	0.7	190
M3	2000	High	230	70,000	40	1,000	900	5	14	60	0.5	270
		Low	110	60,000	60	1,000	1,100	3	16	50	0.2	200
M4	2300	High	420	115,000	35	800	800	5.5	13	100	0.7	330
		Low	110	80,000	60	1,300	1,300	3	16	50	0.1	210

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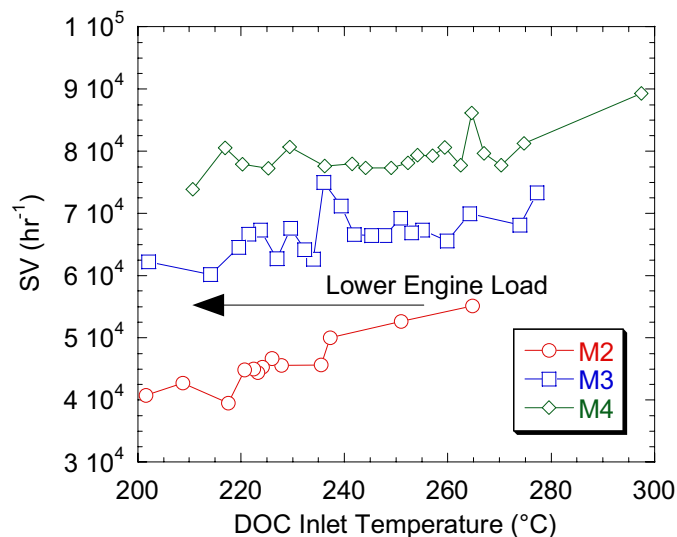


Figure 6: Typical space velocities versus DOC inlet temperature (T3) for engine operating modes M2, M3, and M4

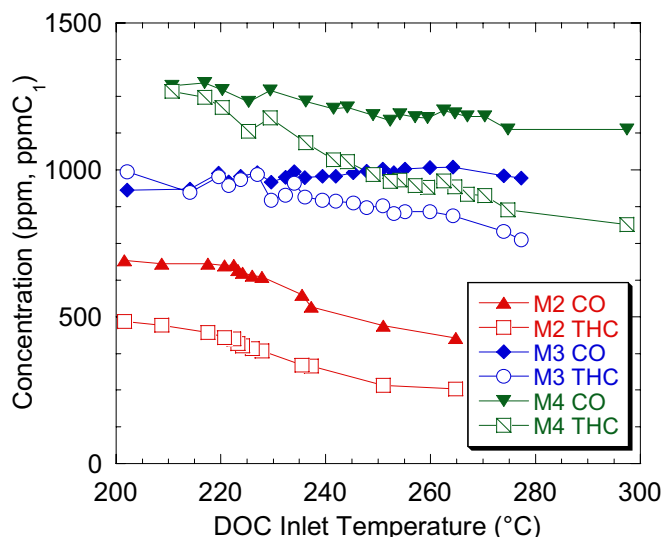


Figure 7: Typical CO and THC feedgas concentrations versus DOC inlet temperature (T3) for engine operating modes M2, M3, and M4

DOC DEGREENING RESULTS

Light-down curves for CO and THC are acquired on the fresh catalyst after 0, 1, 2, 3, 4, 6, 8, 10, 12, and 16 hours of degreening. Figure 8 and Figure 9 show the complete set of light-down curves for CO and THC. They were obtained at engine operating condition M3. Light-down curves are generated for three engine operating conditions, M2, M3, and M4. The engine operating conditions differ, as mentioned earlier, in temperature, space velocity and exhaust gas composition.

Comparing light-down curves at different stages of catalyst degreening reveals that the curves are identical in shape but light-down occurs at higher exhaust gas temperatures as degreening progresses as shown in Figure 8 and 9. Degreening does not affect overall conversion when the catalyst is fully lit. These results are found consistently for CO and THC across the three engine operating modes. The fact that the shape of the curves and the overall conversion are not affected by degreening suggests that only the initial part of the DOC activity is delayed.

In the low temperature regime where light-off begins, it is widely accepted that the conversion efficiency of a catalyst is controlled by chemical kinetics, i.e. chemical kinetics are the rate-limiting factor. At higher conversion efficiencies and temperatures, pore diffusion and bulk gas diffusion are thought to be the rate limiting processes rather than chemical kinetics [2 and 8]. Pore and bulk gas diffusion seem to be unaffected by the degreening process as indicated by the identical slopes and shapes of the light-down curves. This leads to the conclusion that the increase of the catalyst light-down temperature is primarily due to a loss of the precious metal sites, which may be caused by sintering. It is believed that the properties of the Al_2O_3 washcoat, such as specific surface area and pore size, are unaffected by the degreening temperature of 650°C.

During the initial hours of degreening, light-down temperatures increase rapidly and light-down curves are distinctly spaced with little to no overlap. In the later part of the degreening process, however, instances are observed where the catalyst seems to regain activity and light-down occurs at lower temperatures than at some of the cases with fewer hours of degreening. This is attributed to day-to-day and test-to-test variability. The experiments are run in an environment in which ambient temperature and humidity cannot be precisely controlled and thus vary from day to day.

T50, the temperature at which a catalyst is 50% active for a particular species, is a common performance indicator. Figure 10 and 11 show T50 for CO and THC respectively versus degreening time. T50 increases rapidly during the first 8 hours of degreening and then stabilizes. Changes in T50 from 8-16 hours are small and do not exceed measurement uncertainty. T50 CO light-down is shifted by 14°C through the degreening process for all three operating modes.

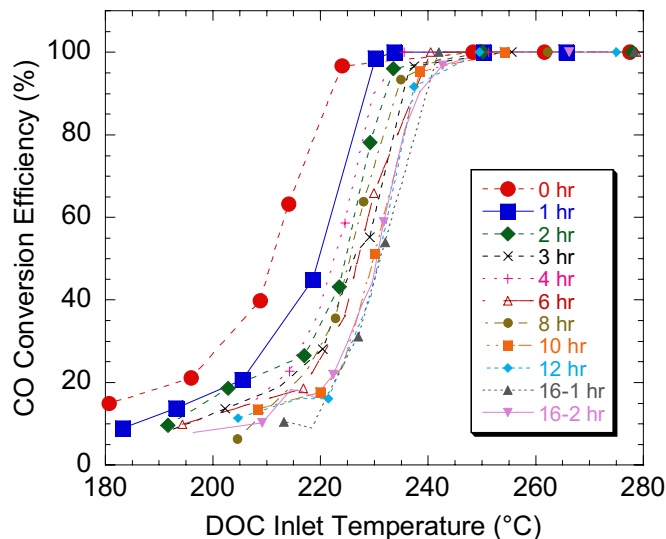


Figure 8: CO light-down curves at 0, 1, 2, 3, 4, 6, 8, 10, 12, and 16 hours of degreening; engine operating mode M3

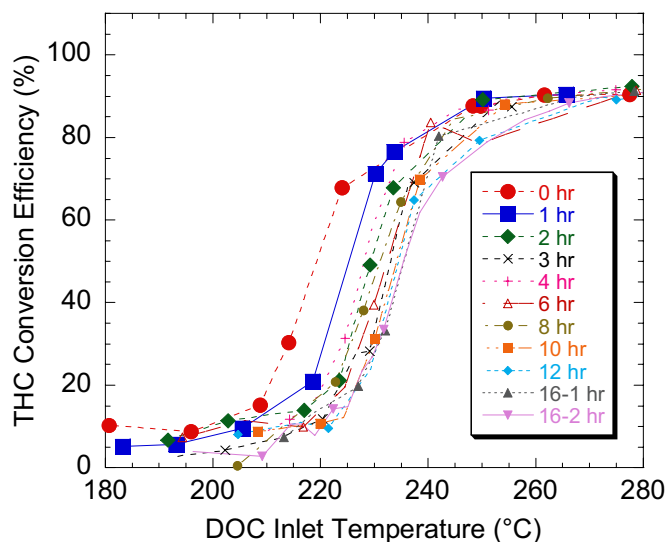


Figure 9: THC light-down curves at 0, 1, 2, 3, 4, 6, 8, 10, 12, and 16 hours of degreening; engine operating mode M3

At modes 3 and 4, catalyst light-down occurs at higher temperatures as shown in Figure 10, which is probably due to higher space velocities and species concentrations for these cases. Catalyst light-down for THC shows very similar trends. T50 increases rapidly during the initial 8 hours of degreening and then stabilizes to a large degree. Overall, T50 for hydrocarbons shifts by 11°C compared to 14°C for CO. Higher space velocities delay catalyst light-down for M3 and M4 similar to catalyst behavior for CO conversion. The fact that the catalyst activity stabilizes after 8 hours of exposure to 650°C in the presence of actual diesel engine exhaust gas suggests that the platinum dispersion is largely stabilized at this point.

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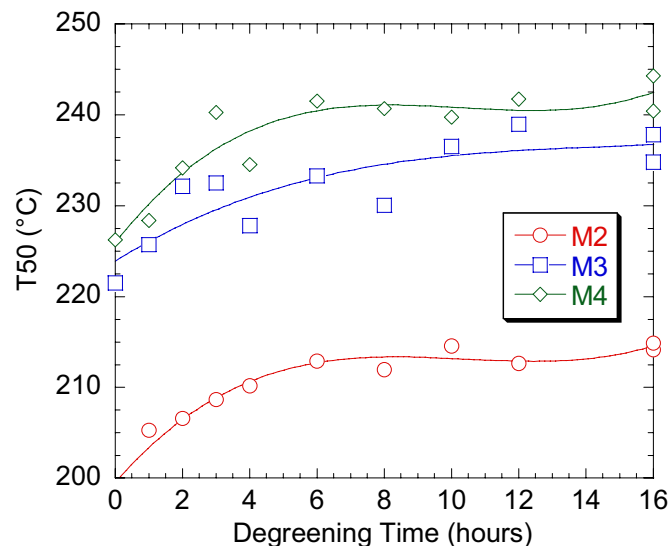


Figure 10: T50 (DOC inlet temperature T3) for CO versus degreening time

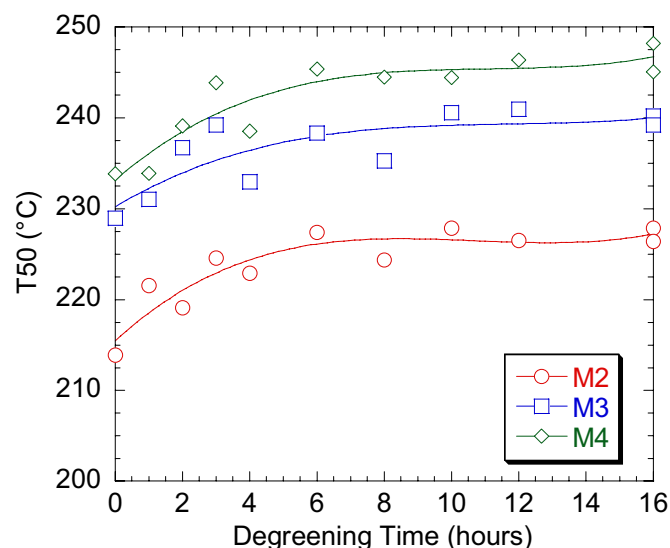


Figure 11: T50 (DOC inlet temperature T3) for THC versus degreening time

Figure 12 shows the light-down characteristics of the fully degreened catalyst with respect to CO. When the DOC is fully lit, the conversion efficiency reaches 100%. At M2 the catalyst deactivates at a lower temperature and more rapidly than at M3 and M4. In mode 2, conversion decreases from 80% to 20% when the DOC inlet temperature is decreased by 11°C. For M3 and M4 this temperature difference is 13°C. Note that 20 – 50% conversion occurs over the same temperature span for all three cases but 50 – 80% conversion occurs over 4°C for M3 and M4 versus 2°C for M2. CO, THC concentrations, and space velocities are higher for modes 3 and 4; thus CO-inhibition, pore diffusion and bulk gas diffusion may cause the differences in light-down behavior for the 3 operating modes.

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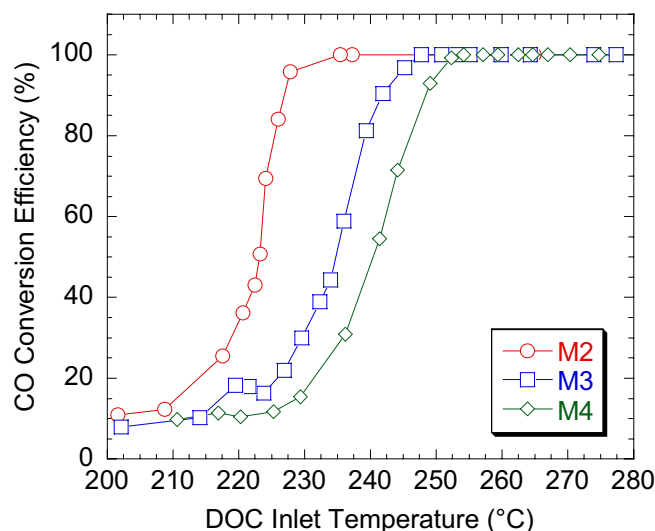


Figure 12: Fully degreened catalyst light-down curves for CO versus DOC inlet gas temperature (T3)

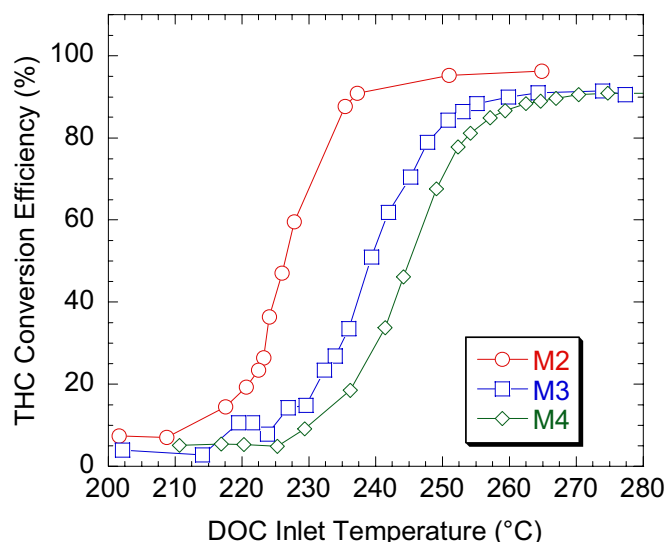


Figure 13: Fully degreened catalyst light-down curves for THC versus DOC inlet gas temperature (T3)

Light-down behavior of the fully degreened DOC with respect to THC is shown in Figure 13. The maximum conversion efficiency is ~95% for M2 and slightly lower (~90%) for M3 and M4. In order to obtain more insight into the catalyst's ability to oxidize hydrocarbons, hydrocarbon speciation was performed during the degreening process.

HYDROCARBON SPECIATION

Engine Operating Condition for HC Speciation

HC samples are taken pre and post DOC at 0, 4, 8, and 16 hours of degreening. Engine operating mode M3 (2000 rpm / 200 kPa BMEP) is chosen as the engine operating condition. As discussed earlier, conversion efficiency of the catalyst in the partially active regime is very sensitive to temperature. It is therefore necessary to accurately repeat and control the feedgas properties

and temperature into the catalyst when the effect of degreening is investigated. Average feedgas temperature is controlled to be within $247.5 \pm 1.5^\circ\text{C}$ and a standard deviation of less than 0.5% over the 5 minute sampling time. The average EGR rate must be within $29.2 \pm 2\%$, and the standard deviation of hydrocarbons at the catalyst inlet must not exceed 5% over the test duration. All HC speciation data shown in the subsequent sections meet the conditions listed above.

Carbon number resolved hydrocarbon concentrations are shown in Figure 14. The four curves represent catalyst inlet and outlet HC species at 0 and 16 hours of degreening. Despite higher HC concentrations at the inlet for the 0 hour test case, lower HC concentrations are found at the exit of the catalyst. This indicates that the HC conversion efficiency of the catalyst deteriorates through the degreening process, which confirms earlier findings. It can be seen that hydrocarbons of all carbon numbers are oxidized through the catalyst except C_1 , which corresponds to methane (CH_4). Throughout this investigation, the methane concentration seems to be largely unaffected by the catalyst.

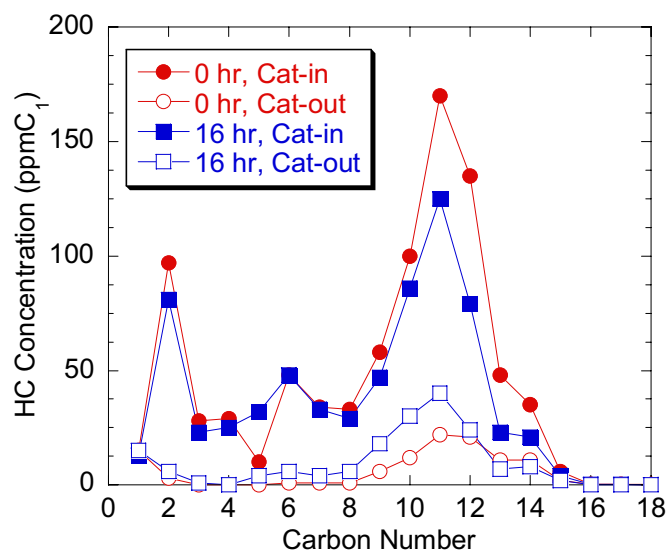


Figure 14: HC species resolved by carbon number pre and post DOC after 0 & 16 hours of degreening (green and degreened catalyst)

THC and CO conversion efficiencies at engine operating mode M3 are listed in Table 4. Note, in this section, THC and HC specific conversion efficiencies are determined via gas chromatography while CO is determined via a chemiluminescence detector (CLD). Conversion efficiency for CO is 100% in all cases. For HC, however, the catalyst shows monotonically lower conversion efficiencies as degreening progresses. Both trends are confirmed by Figure 8 and Figure 9.

Table 4: Conversion efficiency versus degreening time at engine operating mode M3

Time (hours)	CO	THC
0	100%	92%
4	100%	89%
8	100%	81%
16	100%	78%
Feedgas, 0 hr	944 ppm	904 ppmC ₁

Four groups of hydrocarbons commonly found in engine exhaust are acetylenes, olefins, aromatics and paraffins. Acetylenes or alkynes are hydrocarbons with at least one carbon – carbon triple bond; olefins, also known as alkenes, are hydrocarbons with at least one carbon – carbon double bond; aromatics or arenes are HCs with one or more sets of 6 planar carbon atoms; and paraffins or alkanes are fully saturated hydrocarbons.

Table 5: DOC conversion efficiency versus degreening time for Acetylenes + Olefins, Aromatics and Paraffins

Time (hours)	Acetylenes + Olefins	Aromatics	Paraffins
0	99 %	93 %	80 %
4	98 %	87 %	76 %
8	96 %	79 %	66 %
16	92 %	74 %	63 %
Feedgas, 0 hr	168 ppmC ₁	100 ppmC ₁	299 ppmC ₁

Conversion efficiency through the catalyst is found to be highest for acetylenes and olefins, followed by aromatics and paraffins as shown in Table 5. Catalyst activity deteriorates with degreening across all HC groups but

most severely for aromatics and paraffins. It can be seen that the rate of change in conversion efficiency is much higher over the initial eight hours of degreening compared to the later 8 hours of degreening. This suggests that the catalyst is mostly, but not completely, stable after 8 hours of degreening.

Individual major hydrocarbon species from the olefin and acetylene group are given in Table 6. Acetylene and heavy olefins such as 1-butene, 1-pentene and 1-hexene, are found to be among the most reactive hydrocarbons in the DOC. The catalytic converter is 100% active for those species regardless of degreening. Ethene and propene are readily oxidized by the green catalyst but show slightly lower conversion rates through the degreened catalyst.

Selected aromatic species and normal paraffins present in the exhaust are listed in Table 7 and Table 8. The catalyst shows virtually no activity for methane and actually produces methane for the 4, 8 and 16 hour tests as indicated by the negative conversion efficiencies. This may be due to cracking of heavier hydrocarbons by the catalyst where methane is formed as one of the products. The remaining aromatics and olefins show similar trends with catalyst degreening. Oxidation rates through the catalyst decrease rapidly over the initial 8 hours of degreening, and then decrease only a few percentage points through the additional 8 hours of degreening. Conversion of n-tetradecane shows essentially no change with catalyst degreening.

Table 6: DOC conversion efficiency versus degreening time for acetylenes and olefins

Time (hours)	Acetylene (C ₂ H ₂)	Ethene (C ₂ H ₄)	Propene (C ₃ H ₆)	1-butene (C ₄ H ₈)	1-pentene (C ₅ H ₁₀)	1-hexene (C ₆ H ₁₂)
0	100%	99%	100%	100%	100%	100%
4	100%	97%	100%	100%	100%	100%
8	100%	95%	96%	100%	100%	100%
16	100%	93%	94%	100%	100%	100%
Feedgas, 0 hr	22.4 ppmC ₁	74.8 ppmC ₁	25.9 ppmC ₁	14.9 ppmC ₁	4.1 ppmC ₁	4.0 ppmC ₁

Table 7: DOC conversion efficiency versus degreening time for major aromatic species

Time (hours)	Benzene (C ₆ H ₆)	Toluene (C ₇ H ₈)	n-propylbenzene (C ₉ H ₁₂)	1,4-dimethyl-2-ethylbenzene (C ₁₀ H ₁₄)	1,2-dimethyl-3-ethylbenzene (C ₁₀ H ₁₄)
0	99%	99%	97%	88%	89%
4	97%	96%	94%	85%	87%
8	91%	88%	92%	72%	79%
16	87%	85%	90%	66%	75%
Feedgas, 0 hr	18 ppmC ₁	10.3 ppmC ₁	10.4 ppmC ₁	9.3 ppmC ₁	6.3 ppmC ₁

Table 8: DOC conversion efficiency versus degreening time for n-paraffins

Time (hours)	Methane (CH ₄)	n-decane (C ₁₀ H ₂₂)	n-undecane (C ₁₁ H ₂₄)	n-dodecane (C ₁₂ H ₂₆)	n-tridecane (C ₁₃ H ₂₈)	n-tetradecane (C ₁₄ H ₃₀)
0	2%	86%	87%	84%	81%	66%
4	-10%	81%	83%	83%	77%	66%
8	-17%	66%	70%	72%	70%	69%
16	-13%	61%	67%	69%	67%	64%
Feedgas, 0 hr	14.8 ppmC ₁	33.6 ppmC ₁	80.2 ppmC ₁	86.3 ppmC ₁	19.2 ppmC ₁	16.1 ppmC ₁

SUMMARY AND CONCLUSION

A model catalyst was degreened at 650°C and 10% H₂O for 16 hours on a light duty diesel engine. Light-down curves were collected at 0, 1, 2, 3, 4, 6, 8, 10, 12, and 16 hours of degreening. The engine exhaust was analyzed for HC species via gas chromatography and catalyst activity was determined for various HC species at 0, 4, 8, and 16 hours of degreening.

As the catalyst is degreened, the catalyst light-down temperature increases. Light-down temperatures increase rapidly over the first 8 hours and then largely stabilize. T50 increases by 14°C for CO and by 11°C for THC through the degreening procedure. The shape of the light-down curves is not affected by the degreening process. Conversion efficiency of the fully lit catalyst is unaffected by degreening. It is believed that the catalyst performance changes due to coalescence of precious metal sites that have been exposed to high temperature. Thus only the initial part of catalytic activity is shifted towards higher temperatures, but the shape and overall conversion efficiency remains constant.

Hydrocarbons speciation suggests that the oxidation catalyst is not equally active for all hydrocarbon species. The oxidation catalyst is most active for acetylenes, then olefins and aromatics. Paraffins show the lowest activity through the oxidation catalyst. Little to no change in methane concentration is observed through the catalyst. Catalyst activity deteriorates with degreening across all HC groups but most severely for aromatics and normal paraffins.

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ABBREVIATIONS

AFR	Air Fuel Ratio
BMEP	Brake Mean Effective Pressure (kPa)
CO	Carbon Monoxide
CO ₂	Carbon Dioxide
CPSI	Cells Per Square Inch
°ATDC	Degree After Top Dead Center
°C	Degree Celsius
°CA	Degree Crank Angle
DOC	Diesel Oxidation Catalyst
EGR	Exhaust Gas Recirculation
FSN	Filter Smoke Number
H ₂ O	Water
HC	Hydrocarbon (ppmC1)
HCCI	Homogeneous Charge Compression Ignition
Hr	Hour
HSDI	High Speed Direct Injection
ICP	Injection Control Pressure
LHV	Lower Heating Value
Mx (e.g. M2)	Engine Operating Mode (e.g. M2)
NO	Nitric Monoxide
NO _x	Nitric Oxide
O ₂	Oxygen
PCI	Premixed Compression Ignition
PM	Particulate Matter
ppmC	Parts Per Million Carbon Atoms
ppmC1	Parts Per Million Hydrocarbon on a C1 basis
Txx (e.g. T50)	Temperature at which xx% of a particular species is converted (e.g. 50%)
THC	Total Hydrocarbons (ppmC1)
SV	Space Velocity (hr ⁻¹)
VGT	Variable Geometry Turbine

Methane Emissions from Gathering and Boosting Compressor
Stations in the U.S.:
Supporting Volume 3:
Emission Factors, Station Estimates, and National Emissions
October 2019 Revision

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S3-1 Field Campaign

This section provides an overview of the field campaign for the entire project and the data collected in the field campaign data and during the analysis phase of the project.

Accompanying data files:

All data tables referenced in this report are provided in the file *DataTable.xlsx*. Sheet names are given as needed throughout the document in italics; for example, a listing of partner data can be found in *D10 Partner Site Data*.

Throughout this volume we refer to a single compressor station as a “station” and reserve the term “facility” to refer to all operations by one company in one basin, in keeping with the EPA’s Greenhouse Gas Reporting Program’s definition of a *gathering and boosting facility*.

S3-1.1 Sampling Plan

Prior to the field campaign, partners provided lists of their stations along with basic information about the stations, including the location, number of compressors, a simple classification of the site type, and whether the station handled primarily *wet* or *dry* gas. In the context of this study, wet gas is defined as gas with less than 95% methane content. The partner data gathered is in sheet *D10 Partner Site Data*. Each partner was assigned an arbitrary letter ID, “A” through “I”.

The field campaign was conducted using geographically-clustered random sampling. The sampling procedure was as follows:

1. Basins where partners operated were selected to be representative of the mix of USA production basins.
2. In each basin, one or more partners were selected that had substantial operations in the basin. Field campaign weeks were dispersed such that each partner provided site access and support for a total of 2-3 weeks during the campaign.
3. Within the basin, for each week scheduled in the basin, one partner was selected as the host for that week.
4. For each campaign week, five random stations were selected from the partner’s stations within the basin. These five stations were organized geographically to minimize travel time between stations, typically completed in the evening or overnight. These stations were designated the “primary” stations for each day.
5. For each selected station, 3-5 nearby stations were identified using distance calculations, and ordered by distance. These secondary stations were measured in predetermined order if work was completed at the first station in less than a day.
6. Key characteristics of all selected stations for all campaign weeks were checked against the characteristics of all partner stations to assure a representative sample. The primary parameters checked were:

- (a) The type of station: compression, dehydrating, treating, and other station types.
- (b) The size of the station; the number of compressor engines was utilized as a surrogate for size.
- (c) Whether the station handled wet or dry gas.

Note that geographical diversity was assured by the selection of basins.

7. The above plan was shared with the host partner, who reviewed the site selection for any major issues. If a station was under major repairs, the station was excluded for safety reasons and its likely lack of pressurization, which could lead to unrepresentative emissions. Stations with high H_2S gas, where special breathing equipment was required, were also excluded from the field campaign.
8. Driving distances between stations were checked after selection, and if these differed substantially from the predetermined order, the order of the stations was changed to minimize travel time between stations.

The above plan was designed to maximize the number of stations measured during the campaign, while still measuring the appropriate mix of stations. The resulting diversity of stations selected for the field campaign matched the diversity of partner stations to within $\pm 12\%$ on these selected categories. Figure S3-1 overlays selected regions to the county level and measured stations for the entire field campaign. Counties are colored by gas production, illustrating that the campaign measured a diversity of production rates, including, importantly, the highest producing counties in the USA.

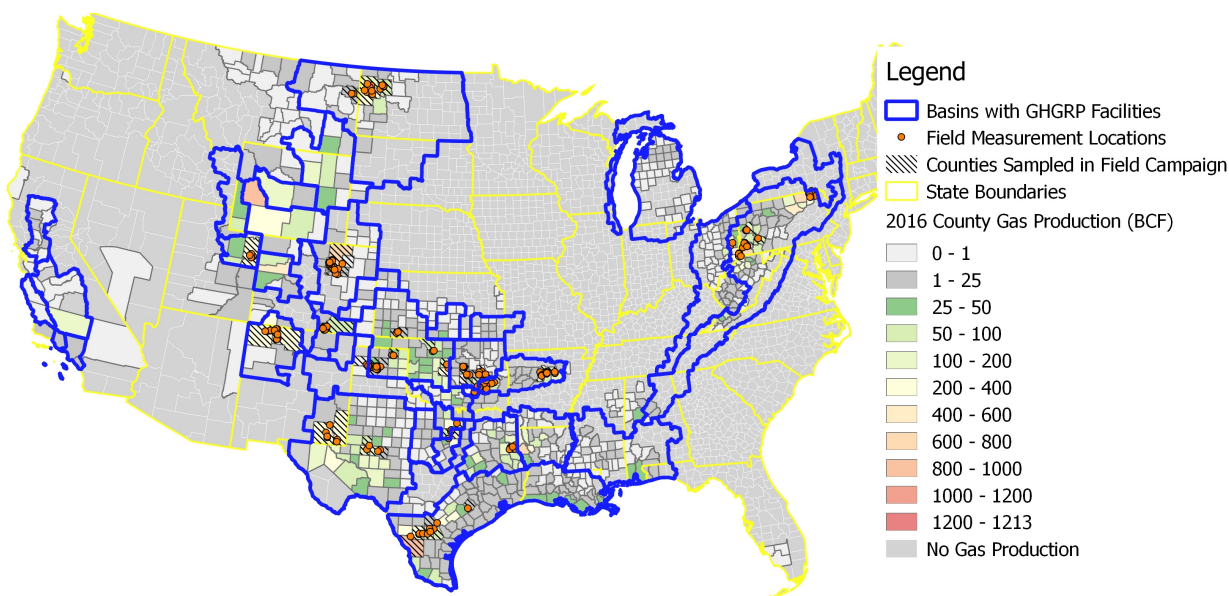


Figure S3-1: Map showing locations measured during the field campaign. Blue outlines indicate AAPG basins used for GHGRP reporting. Gas production is taken from DrillingInfo™ data.

Field teams measured the primary station and then moved on to secondary stations, in pre-planned order, each day. The number of stations measured varied by day - on some days only the primary station was measured, while on others the team completed all selected stations and

moved on to the next day's stations. The speed of measurement depended primarily upon the complexity of the station, although weather, road conditions, and distance between stations were also factors. Typically, teams measured 1-5 stations per day (except for 2 days where eight or more small stations were measured). The resulting mix of measured stations differed from the original station list and mix developed during campaign planning. However, the station mix closely aligns with the field campaign design. Figure S3-2 illustrates the mix of stations measured in the field campaign compared with the all stations in the partner population.

Two measurement teams were deployed for the field campaign. Both teams were equipped with one or more optical gas imaging (OGI) cameras for detecting emissions, a high flow sampler and other equipment for measuring emissions (see Section S3-1.3). In addition, Team 1 was equipped with six gas meters for long-term recording of pneumatic controller emissions (see Luck et al.[1]) and a set of equipment for measuring methane entrained in engine exhaust, a major source of emissions for gathering stations (see Vaughn et al.[2]). Team 1 completed 11 weeks of measurement while Team 2 completed 8 weeks.

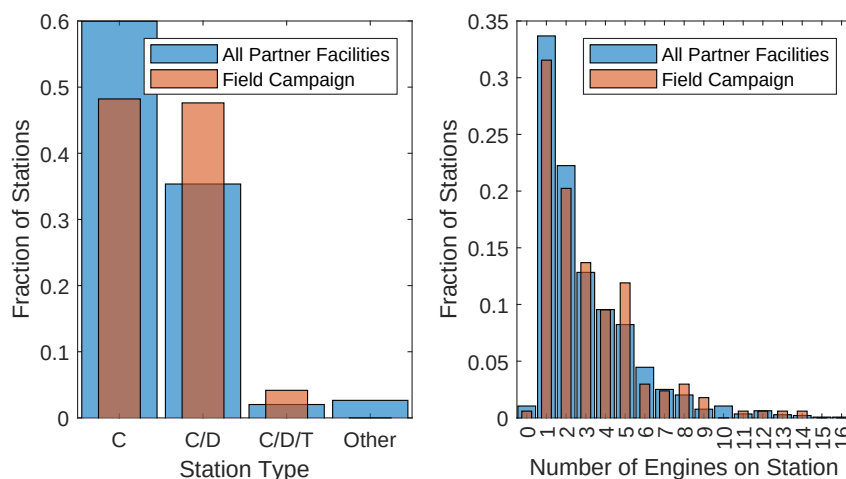


Figure S3-2: Mix of station types in the field campaign. Stations are classified by the type of major equipment on the station, where *C* indicates compression, *D* indicates dehydration, *T* indicates acid gas removal (treating). *Other* includes stations with no compressors.

For each measurement day, emissions detection and measurements were completed on *units* of *major equipment*, including: compressors, dehydrators, acid gas removal (AGRU, also known as *treaters*) skids, station separators, atmospheric tanks, and yard piping. While all types of tanks would have been measured, field teams encountered only atmospheric tanks - i.e. tanks kept at near atmospheric pressure, and typically vented to the atmosphere directly or through a combustion device (e.g. a flare) or a vapor recovery unit (a small compressor that compresses gas and injects it into the sales or fuel system on the station).

Yard piping was broken into sections for ease of processing, and each section was recorded, screened and measured as a unit. While all stations have at least one yard piping unit, some stations had several. Typical units of yard piping include fuel gas systems, station inlet and outlet headers, meter runs, and pig launchers and receivers. In addition, measurement teams occasionally divided yard piping into arbitrarily numbered subsets for ease of measurement. Measurement categories are further defined in Section S3-1.5. The measurement team selected units to screen

with OGI, and, time permitting, measured any leaks found on the unit. Both screening data and measurements were recorded *only if the entire unit was screened and/or measured*. Regardless of how yard piping was divided into subsets at a station, yard piping is considered screened measured for a station only if all subsets of yard piping at that station were screened and measured.

On each measurement day, the team screened equipment with an OGI camera and measured emissions as found. When all major equipment units at a station were measured, the team would move to a nearby station on the selected list and continue measuring. Similarly, measurement teams would count components on major equipment units for use as activity data. As with measurement data, counts were recorded only if all components on the unit were counted. For identical skid-based equipment, the count on one skid was applied to all identical skids on the station.

It is important to note that the sampling of equipment for counting and measurement was independent; a particular unit of major equipment may have been counted but not measured, or measured but not counted. Component types counted are described in S3-1.5. Field protocols are included in the appendices: *Appendix D Field Protocol.pdf* covers overall field measurement and counting protocol, *Appendix E Component Counting Protocol.pdf* provides instructions for component counting, and *Appendix F HiFlow Sampler Reach Protocol.pdf* provides for methods for reaching high emission locations.

Data was accumulated into two tables, *D8 Measurements* for all OGI detections and measurements, and *D9 Equipment* for all major equipment records and component counts. Tables are tied together by a major equipment ID consisting of a station identifier (randomly assigned integer in [1,3000]), equipment type, and an equipment ID. Additional qualifying fields provide more detail on the type of equipment.

During the field campaign, field teams made 229 measurements of pneumatic controllers (PCs) using the same methods as utilized for other emission sources (see Section S3-1.3). While these measurements last a few minutes, long duration measurements of PCs are required to adequately characterize emissions, and the measurement protocol did not distinguish between normal and abnormal operation of the controllers. Therefore, these measurements *are not* included in the measurement data set.

In addition, gas flow meters were installed at stations to measure PC emissions over an extended period [1]. These measurements could provide updated emissions factors for PCs, but due to a measurement error, additional corrections were made to some recordings and some recordings were discarded. To void any potential bias in the sample, this study instead utilizes emission factors from the GHGRP for all PC emissions.

S3-1.2 Additional Data from Longitudinal Compressor Study

Coincident with the field campaign for this study, GSI Environmental, Inc., completed a longitudinal* study of four compressor stations in southeast Texas. During campaign planning, the teams from both studies coordinated sampling methods and data collection. Following GSI's campaign, GSI provided their measurement data to CSU for inclusion in the CSU study.

*A longitudinal study looks at a, typically smaller, study population multiple times. The main study presented here is "latitudinal" - it looked at a larger sample population one time; i.e. a snapshot in time.

The GSI study focused on multiple measurements of the compressor stations over a one year period. Therefore, each compressor station was visited several times, screened with OGI, and measured using the high flow method. Since each unit was measured multiple times, potentially finding different emission locations or different emission rates at the previously identified locations, multiple emission measurements at any emission location were averaged before inclusion in the study data set to avoid unduly weighting these four stations relative to the other stations in the study. The impact of including this data is shown in Table S3-1. For reference (not used in the study), the impact of including all measurements without averaging is included in Table S3-2.

Stations included from the GSI study were assigned station IDs 3001 to 3004 in the study data sets and are assigned a partner ID code of “J”.

Table S3-1: Categories Impacted by Additional GSI Data

Category ¹	Meas. Count	Added Meas. Count	No GSI Data	With GSI Data	Relative Difference In Mean
Compressor PRV	33	2	17.8	21.2	20% [17% to 21%]
Non-compressor PRV	20	3	9.18	10.8	18% [15% to 21%]
Compressor Rod Packing Vent	353	37	26.2	28	7.6% [6% to 7.9%]
Non-compressor Regulator	37	6	7.76	8.05	3.3% [2.7% to 3.9%]
Compressor Connector Flanged	39	2	11.8	12.1	3% [2.7% to 3.5%]
Compressor Valve	38	1	40.5	41.2	2.1% [1.9% to 2.5%]
Compressor Blowdown Vent	29	1	21.8	21.5	-2% [-5.8% to -0.12%]
All Pump	11	1	36.6	35.6	-3.7% [-7.8% to -1.8%]
Compressor Regulator	34	3	14.5	13.8	-4.4% [-4.9% to -3.9%]
Non-compressor Valve	86	13	8.39	7.88	-6.1% [-9.2% to -3%]
Compressor Connector Threaded	98	9	15.8	14.6	-7.3% [-9.9% to -6%]
All Other	36	6	27	24.1	-10% [-12% to -8.6%]
Compressor Pocket Vent	19	4	9.45	7.82	-17% [-19% to -16%]
Non-compressor Connector Flanged	25	6	9.7	7.92	-18% [-20% to -17%]

¹ Categories with more than 1% change shown

Table S3-2: Categories Impacted by Non-Averaged GSI Data

Category ¹	Meas. Count	Added Meas. Count	Without GSI Data	With GSI Data	Relative Difference In Mean
Compressor PRV	33	5	17.8	31.6	80% [73% to 82%]
Non-compressor PRV	20	3	9.18	10.8	17% [14% to 21%]
Compressor Rod Packing Vent	353	80	26.2	27.9	7.4% [4.7% to 8.9%]
Compressor Valve	38	2	40.5	41.8	4.2% [3.5% to 4.5%]
Compressor Connector Flanged	39	3	11.8	12.2	3.3% [2.9% to 3.7%]
Non-compressor Regulator	37	7	7.76	8.02	2.8% [2.3% to 3.5%]
Non-compressor Connector Threaded	71	15	5.72	5.68	-1% [-1.8% to -0.48%]
Compressor Blowdown Vent	29	1	21.8	21.3	-2% [-6.9% to 0.41%]
All Pump	11	1	36.6	35.7	-3.5% [-7.7% to -2.1%]
Compressor Regulator	34	3	14.5	13.9	-4.3% [-4.9% to -3.8%]
Non-compressor Valve	86	21	8.39	7.97	-4.9% [-9.4% to -0.52%]
Compressor Connector Threaded	98	9	15.8	14.7	-7.5% [-9.4% to -6.1%]
Compressor Pocket Vent	19	4	9.45	7.8	-17% [-19% to -16%]
All Other	36	12	27	22	-17% [-21% to -15%]
Non-compressor Connector Flanged	25	7	9.7	7.68	-21% [-22% to -19%]

¹ Categories with more than 1% change shown

S3-1.3 Measurement Equipment

Leaks were detected utilizing infrared gas cameras, commonly known as *optical gas imaging* or *OGI*. Both Opgal EyeCGas and FLIR GF320 cameras were used. The detection threshold of these cameras is an active research area. Ravikumar et al. [3] suggest a 90% detection efficacy of $\epsilon = 1.845d^{1.925}$, where d is the observation distance from the camera to the leak location. For this study, we estimate a typical observation distance of 1.5 m, leading to an estimated 90% detection threshold of 0.21 scfh methane.

The primary instrument used to measure fugitive and vented emissions was the Bacharach Hi Flow sampler (BHFS). Several authors have expressed concerns about the operation of the instrument [4, 5, 6]. However a recent report by EPA Inspector General [7] indicates that the instrument provides effective measurements provided that use procedures, spelled out in the instrument's user manual [8] are followed correctly.

A total of 1153 emission locations were measured using the BHFS. For each measurement, 1-4 measurement attempts (i.e. repeat measurements) were made resulting in 2142 total attempts; 844 emission locations had at least two measurement attempts to quantify emissions. In 301 measurement attempts (14% of all attempts), emissions were detected by OGI, but produced a zero emission reading when measured using the high flow instrument. For 103 emission locations, all measurement attempts returned readings of zero.

Given the time delay between the OGI screen and high flow measurement, the emissions may have stopped due to a variety of reasons, including changes in site operation or intermittent equipment operation. However, it is also possible that emissions seen during the OGI screen persisted, but the emission rate was below the lower detection limit (LDL) of the high flow instrument. To assess the instrument's LDL, a controlled release test was performed, with natural gas releases (ap-

proximately 85% methane) from 0 to 0.5 scfh, with the instrument having a 100% detection rate of the emissions at 0.5 scfh. A logistic regression was performed to establish the LDL, as shown in Figure S3-3, of 0.204 scfh. To estimate uncertainty in high flow measurements, a relative accuracy of $\pm 10\%$ was assumed (normally distributed errors, 90% confidence interval). This data is included in the data tables, in sheet *D1 HiFlowLDL*.

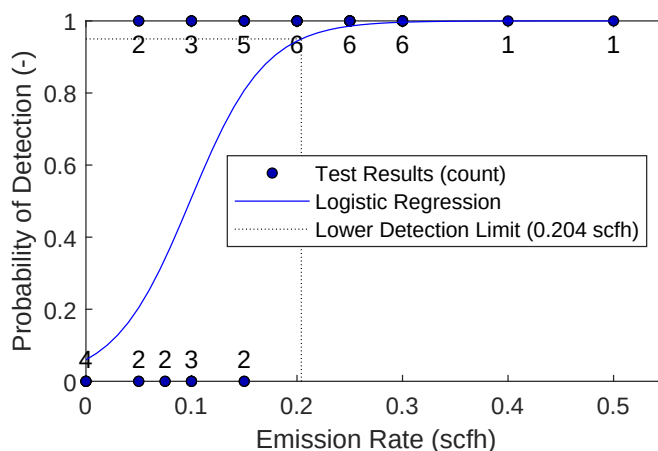


Figure S3-3: Data and logistic regression utilized to develop a lower detection limit (LDL) for one of the Bacharach High Flow samplers utilized in the study. Points represent test conditions performed in outdoor laboratory tests using compressed natural gas. Point labels indicate the number of non-sequential test cases with either detections ($y=1$) or non-detection ($y=0$). The logistic regression and computed lower detection limit at 95% confidence level are also shown.

The BHFS must be corrected for gas composition. These corrections were developed by testing after the field campaign, and are instrument-specific. Six BHFS instruments were utilized in the field campaign. Three of these units were returned to METEC post-campaign to develop corrections: one unit owned by CSU ('CSU' - 544 measurements) and two owned by UT Austin ('UTBlack' - 64 measurements and 'UTBlue' - 7 measurements). The other units were not available after the campaign; one had been stolen during the campaign (the unit id'd as 'AECOM') and the other two were used by partner company personnel and were not available post-campaign. Of the unavailable units only the AECOM unit had been utilized for a large number of measurement attempts (478).

While several authors provide BHFS corrections they utilized for various studies, most corrections were developed by limited testing – typically one or two gas compositions fed directly to the BHFS sensor. In contrast, the corrections presented here use specialized equipment at METEC to vary both flow rate and methane composition over a wide range by mixing methane, ethane and propane using mass flow controllers. This system is capable of controlled emission rates of 1-100 slpm. Resulting emissions were introduced directly into the intake of the instruments. Therefore, the resulting corrections include all instrument subsystems, including flow measurement and sensor behavior. All test data is provided in the data tables, in sheet *D6 BHFS Test Data*.

The resulting test data is shown in Figure S3-4 for all three available BHFS instruments. The data clearly indicates a dependence on both gas composition, as indicated in the BHFS manual, and *also* on indicated flow rate (i.e. the flow rate reported on the instrument screen), which is not mentioned in the BHFS manual. The flow rate dependence could be due to variation in the flow

rate sensor (an orifice plate sensor), the concentration sensor, or could be a software artifact.

Data was collected over a multi-month period, when METEC and staff were available and weather conditions supported outdoor use of the equipment. Gas compositions used in testing mirror those seen in the field. The BHFS senses gas concentration using a single pellistor sensor operating in two modes, a catalytic oxidation (CatOx) mode which operates up to a gas concentration of approximately 5%, and a thermal conductivity mode for gas concentration above $\approx 5\%$. The active sensor is noted by observing the number of digits displayed to the right of the decimal point on the gas composition reading: CatOx - 2 digits, TCD - 1 digit [9]. Switching between modes *does not* occur at exactly 5%, and the switching concentration is dependent on the whether input gas is going from low-to-high or high-to-low concentration. Ranges observed in testing at METEC are noted in the titles of the Figure S3-4. The UTBlue unit produced unstable readings near the switch-over point; therefore, the testing team left a gap in the flow rates when collecting test data.

Additional unusual measurement behaviors were observed during testing. Over multiple days of data collection, the testing team saw substantial changes in indicated emissions for the same emission rate, likely due to changes in calibration; the instrument was calibrated before each testing session. As per the instrument manual, each BHFS was calibrated at two points, 2.5% methane in nitrogen and 100% methane. These two calibration points represent single-point calibrations for each of the sensor’s active modes - 2.5% for CatOx and 100% for TCD. In field conditions, the sensor is not operated at 100% methane, as this would violate the “high flow” assumption. This experience indicates that day-to-day variations in calibration may be substantial, and daily calibration – the procedure recommended to avoid sensor transition failure – may actually contribute to uncharacterized measurement uncertainty. Additional investigation is recommended for future projects.

Testing was done in sets, where each set of emissions had an approximately constant flow rate but a series of different methane fractions. A set was included only if the linear regression across methane fractions (concentrations) for a chosen flow rate had $R^2 \geq 0.5$.

Experimentation indicated that a curve fit parameterized on both indicated flow rate and methane fraction produced high R^2 values and produced an easily implemented correction curve. For the CatOx sensor, the form of this correction equation constrains the output (actual flow) to be zero when the indicated flow is zero, since the CatOx mode is utilized for low emission rates. The form of the correction equation for the TCD mode does not require this constraint, and the simplest surface form (bi-linear) was used for the TCD mode.

Since the active sensor is not known in the field data - gas concentration was noted without noting the number of digits on the display (the display behavior was not known at the time of the field campaign) - there exists a gas concentration region where the instrument may be in either sensor mode. In these cases *both* corrections are applied, and the resulting data shows a corresponding increase in uncertainty. When the measurement instrument was not available for testing at METEC, the correction for all three of the available instruments was applied, which resulted in up to six estimates of actual gas flow if the gas concentration was in the transition region of all three instruments.

Parametric values for the resulting corrections are shown in Table S3-3 for CatOx mode and Table S3-4 for TCD mode. Figures S3-5 to S3-7 show the correction curves and test data. Finally, Figures S3-9 and S3-8 compare the three corrections on one plot.

Table S3-3: Corrections for BHFS in CatOx Sensor Mode

$\hat{g} = a_1g + b_1g\phi + c_1g^2\phi$
 where:
 $\hat{g}$ is the actual flow rate (slpm)
 g is BHFS indicated flow rate (slpm)
 ϕ is methane mixing ratio (-)

Coefficient Name	CSU		UTBlack		UTBlue	
	Coefficient Value	Confidence Interval	Coefficient Value	Confidence Interval	Coefficient Value	Confidence Interval
a_1	0.935	± 0.041	0.747	± 0.042	0.736	± 0.042
b_1	0.238	± 0.057	0.311	± 0.064	0.127	± 0.062
c_1	0.0142	± 0.0042	-0.0113	± 0.006	0.0118	± 0.0056
R^2	1		0.99		0.99	

Table S3-4: Corrections for BHFS in TCD Sensor Mode

$\hat{g} = a_1g + b_1\phi + c_1g\phi$
 where:
 $\hat{g}$ is the actual flow rate (slpm)
 g is BHFS indicated flow rate (slpm)
 ϕ is methane mixing ratio (-)

Coefficient Name	CSU		UTBlack		UTBlue	
	Coefficient Value	Confidence Interval	Coefficient Value	Confidence Interval	Coefficient Value	Confidence Interval
a_1	2.48	± 0.097	1.6	± 0.16	1.86	± 0.16
b_1	-2.07	± 1.3	-15.9	± 4.1	8.46	± 2.1
c_1	-1.47	± 0.11	-0.637	± 0.17	-1.3	± 0.17
R^2	0.99		0.84		0.89	

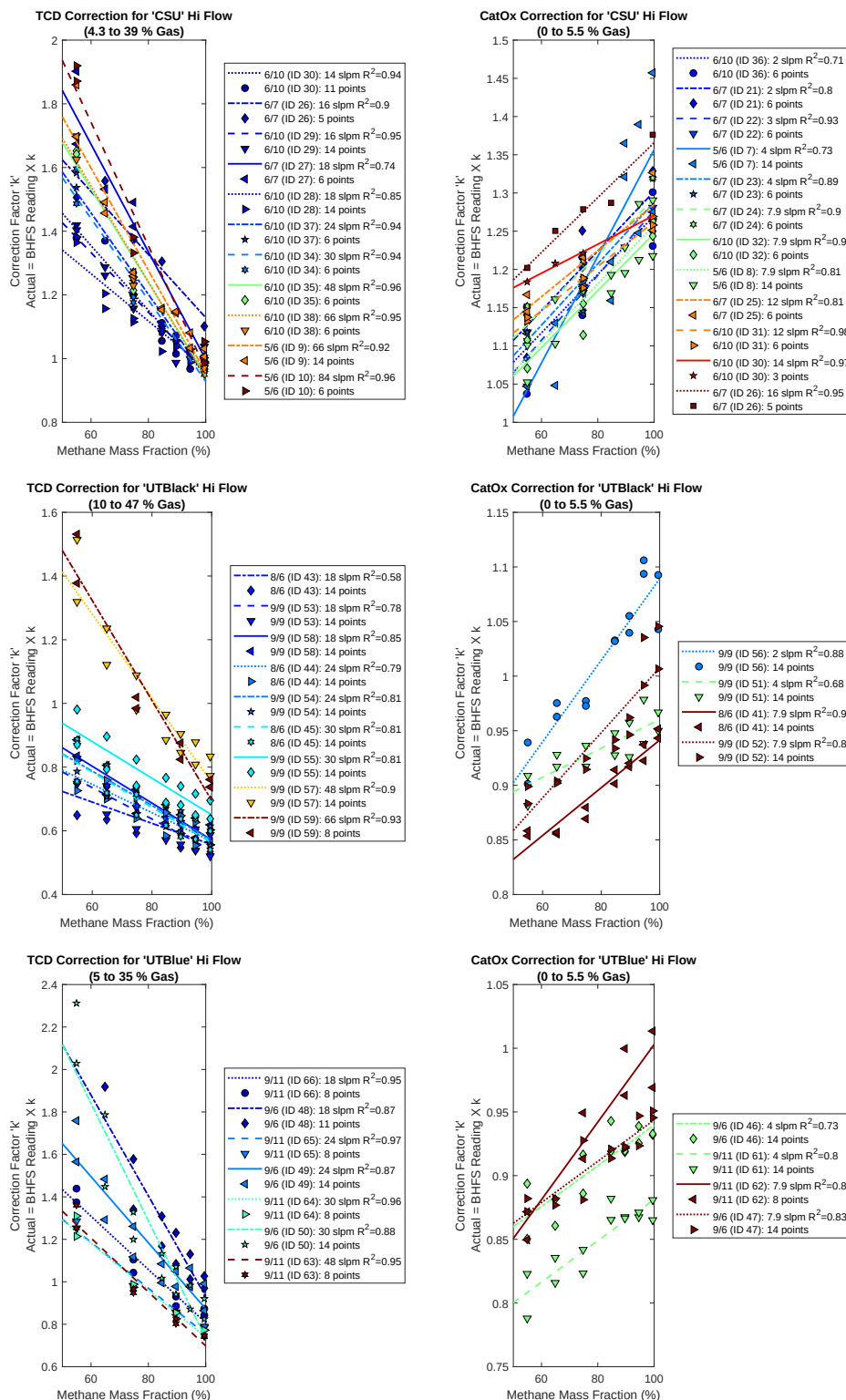


Figure S3-4: Summary of calibration data utilized to develop the gas composition and flow rate correction for the BHFS instruments. Left side of each plot includes all data for when the instrument utilized its sensor in thermal conductivity (TCD) mode; right plot provides the data when the instrument used the same sensor in catalytic oxidation (CatOx) mode.

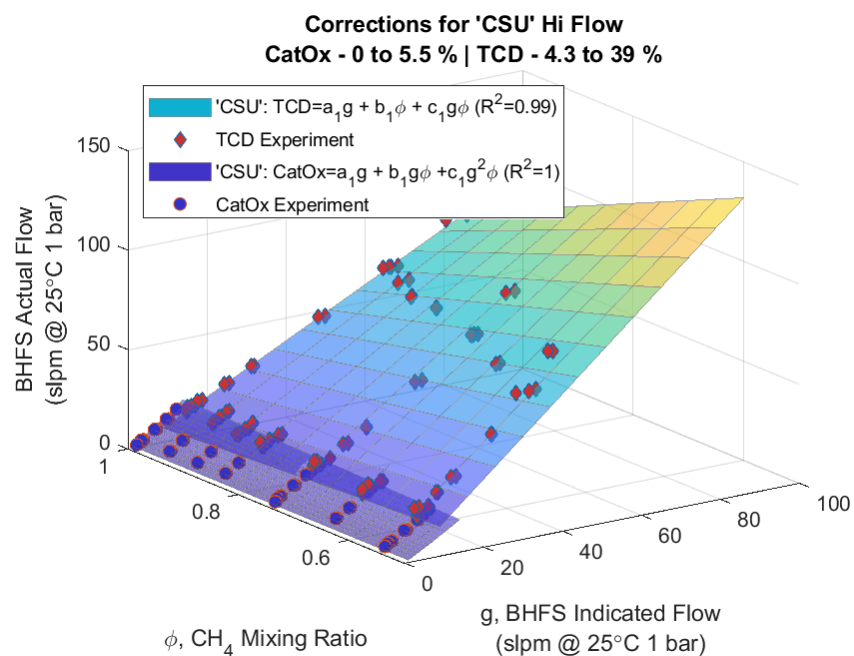


Figure S3-5: Correction surfaces for the CSU BHFS instrument. Standard conditions are 1 atm / 25°C

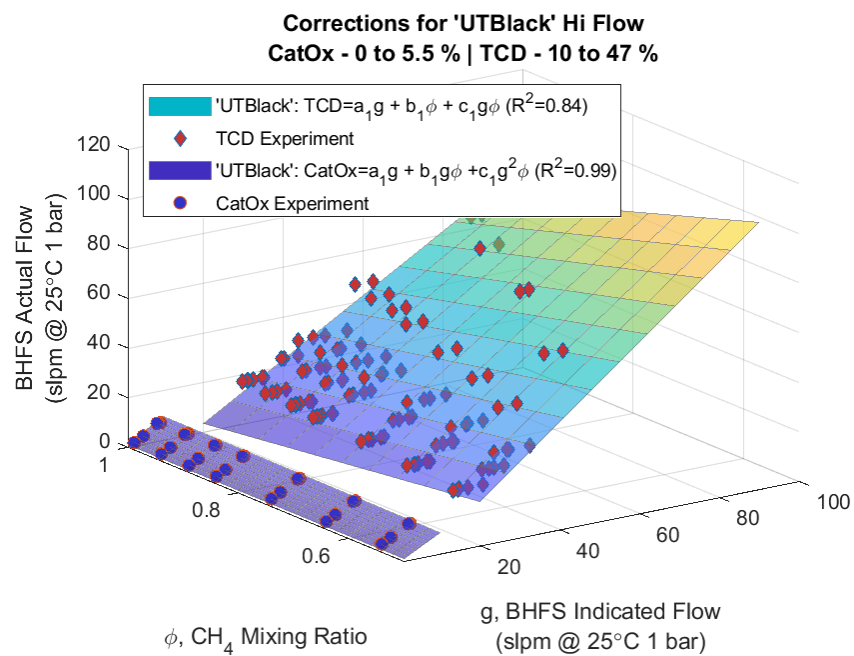


Figure S3-6: Correction for the UT Black BHFS instrument. Standard conditions are 1 atm / 25°C

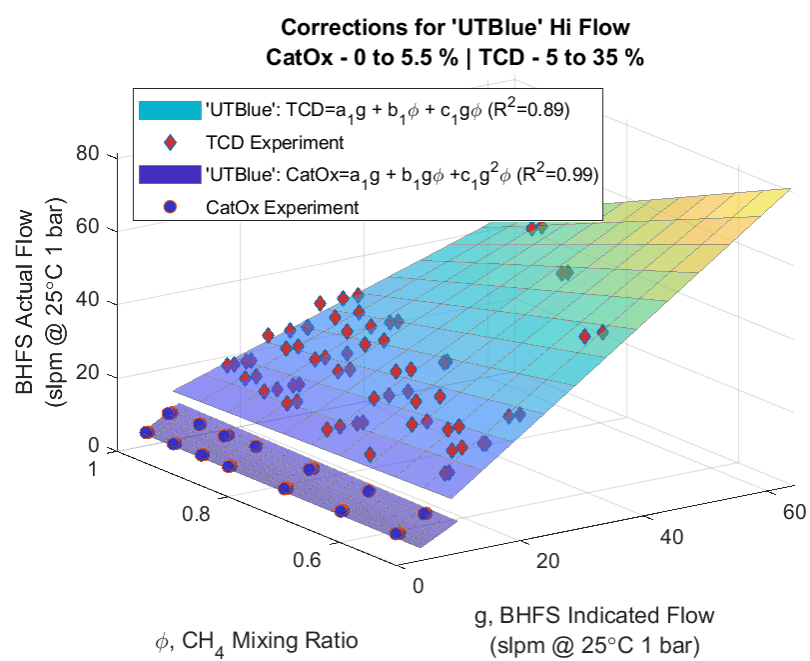


Figure S3-7: Correction for the UT Black BHFS instrument. Standard conditions are 1 atm / 25°C

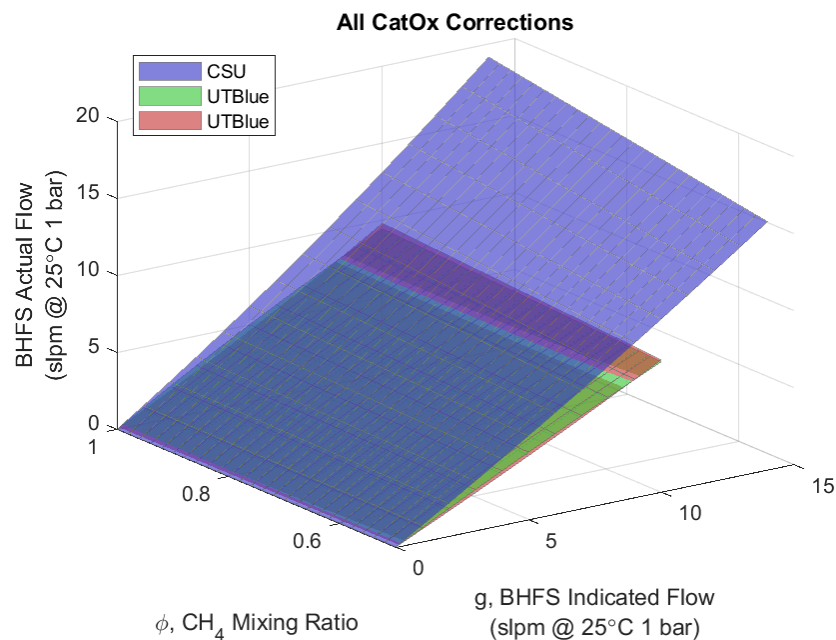


Figure S3-8: Comparison of correction curves for all three BHFS instruments operating in CatOx mode. Standard conditions are 1 atm / 25°C

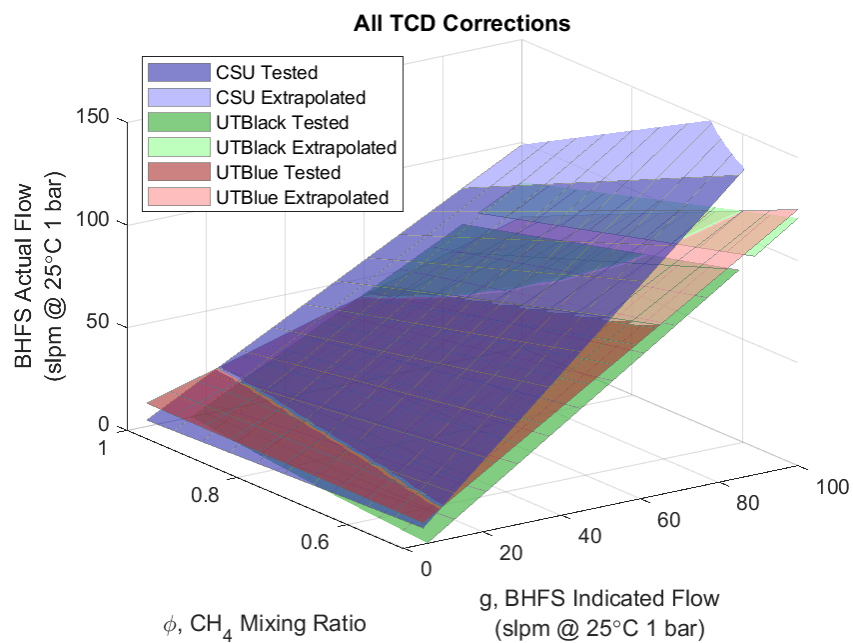


Figure S3-9: Comparison of correction curves for all three BHFS instruments operating in TCD mode. Standard conditions are 1 atm / 25°C

S3-1.4 Bag Measurements

During the field campaign, 4 measurements were made using a bag [10] when the field team judged that the emission was too large for the BHFS. Bag measurements use a $3ft^3$ bag to capture the gas while another operator times how long the emission took to fill the bag. Since few bag measurements were used, and bag measurements have not been tested for accuracy in field conditions, measurement errors were modeled using a normal distribution and a 90% confidence interval of $\pm 20\%$.

S3-1.5 Measurement Data Summary

This chapter provides an overview of the measurement data categorized by the type of major equipment on which the measurement was made, and the component which was measured. Not all component types occur, or were measured, on all types of major equipment. For component emission factors, there are insufficient measurements to develop emission factors for each component type on each type of major equipment. Therefore, emission factors are divided into three major categories:

Compressor: includes components on the compressor skid and associated compressor driver, typically a natural-gas fueled engine or turbine, or an electric motor. See Table S3-5.

Tank: includes all major venting sources on atmospheric tanks; no pressurized tanks were encountered in the field campaign. To simplify the analysis, 3 measurements of minor tank components are included in the *Non-compressor* category. See Table S3-7.

Non-compressor: includes components not associated with either tanks or compressors. See Table S3-6.

The counts listed in the tables include all emissions identified, whether or not they could be successfully measured.

In addition, one measurement made on a dehydrator still vent was eliminated from the analysis, as it was the only measurement of its type. See Section S3-5 for how dehydrator vents were modeled at the station and national levels.

In general, a major equipment unit is identified by the flange or valve which connects the unit to the other equipment at the station. The *compressor* and *tank* categories consist of only one type of major equipment, compressors and tanks, respectively. The *non-compressor* category includes three major equipment types: acid gas removal units (AGRUs), dehydrators, and separators, as well as components on yard piping. Separators in this category include only those separators which are not mounted on the skid of other equipment. For example, an interstage separator on a compressor skid is included in the compressor component counts.

All remaining equipment that is not in one of the above major equipment categories is classified as *yard piping*. During the field campaign, in-line heaters were counted separately, but since only four units were encountered across all stations, these units are counted as yard piping in all subsequent analysis. Yard piping configuration varies between stations, but often includes suction and discharge headers, pig launchers and receivers, fuel gas conditioning and metering equipment,

meter runs, and other miscellaneous support equipment. Yard piping accounts for 69% of non-compressor measurements.

Table S3-5: Compressor Measurement Count

Component Type	Major Equipment Type Compressor	Total
Blowdown Vent	109	109
Common Multi-Unit Vent	23	23
Common Single-Unit Vent	49	49
Connector Flanged	48	48
Connector Threaded	127	127
Other	38	38
PRV	200	200
Pocket Vent	28	28
Regulator	37	37
Rod Packing Vent	530	530
Starter Vent	66	66
Valve	42	42
Total	1297	1297

Table S3-6: Non-compressor Measurement Count

Component Type	Major Equipment Type				Total
	AGRU	Dehydrator	Separator	YardPiping	
Common Station Vent	0	0	0	20	20
Connector Flanged	0	0	5	28	33
Connector Threaded	1	18	12	56	87
OEL	2	3	2	20	27
Other	0	4	3	17	24
PRV	0	44	28	93	165
Pump	0	0	0	15	15
Regulator	0	15	4	28	47
Valve	2	6	17	101	126
Total	5	90	71	378	544

Table S3-7: Tank Measurement Count

Component Type	Major Equipment Type Tank	Total
Common Multi-Unit Vent	22	22
Common Single-Unit Vent	79	79
Thief Hatch	120	120
Total	221	221

S3-1.6 Measurement Quality Indicators

As part of the quality assurance procedure post-campaign, field entries were classified to indicate the quality of the measurement. Based on these classifications, emission measurements were either included in emission factors, excluded, or estimated from available information.

Emission locations which were detected using the OGI camera and measured successfully with high flow instrument or bag are marked as “Measured.” All other measurement entries indicate some type of question or problem with the measurement process.

Two measurement quality indicators indicate that a measurement was attempted, but was unsuccessful. In general, these emission locations are likely to have higher emissions than other locations that were successfully measured.

Value	Description
Exceeded Capacity	Measurement exceeded the upper measurement capacity of the high flow instrument, including two cases: (1) OGI detected where the team attempted to measure, but emissions exceeded capacity of the high flow instrument and a bag would not work, and (2) a measurement was not attempted due to the size of the emission observed by the OGI camera operator and/or safety concerns related to measuring a larger leak. A model was developed to estimate these emissions when calculating major equipment emission factors and station emissions; see Section S3-4.2.
Incomplete capture	Field team could not achieve a sufficiently tight seal to capture all emissions with the high flow instrument. Incomplete captures were identified by observing the measurement process with an OGI camera during measurement – if the camera operator noted emissions that were not captured by the measurement instrument, the measurement was marked as incomplete in field notes. In 11 of 23 cases, the camera operator also estimated the fraction of emissions captured by the instrument. These estimates were utilized to estimate total emissions; see Section S3-2.5.

Additionally, there are five measurement quality indicators that identify cases where emissions could not be measured due to issues unrelated to the size of the emissions:

Value	Description
Inaccessible	Emission locations were identified as inaccessible for one of three reasons: (1) Emissions were detected with OGI, but could not be safely accessed by the measurement team; (2) Prior to the protocol change on July 26 th emission points that should have been measured and could have been safely measured but had no OGI detect were identified as inaccessible, and (3) one case when the OGI camera was not available for detection
Safety	Nearby equipment that was too hot to safely access or personal gas monitor alarmed near the emission location.
Cannot Measure	Measurement conditions were incompatible with the instrumentation available for reasons other than inaccessibility or safety. Examples include conditions when emissions had significant entrained oil vapor, such as a crankcase vent, or when measuring would disrupt the operation of site equipment.
Weather	Too windy to complete measurement.
Other	Includes observed emissions that were fixed before they could be measured and emissions that were not measured due to time constraints

Finally, one measurement quality indicator, *OGI non-detect*, denotes measurements made on leak sources where there was no prior OGI camera detection of emissions. Prior to July 26th the protocol was to measure all compressor and station vents, tank thief hatches and vents, as well

as several other components, even if the OGI screen did not detect emissions. Teams made 429 measurements in this category, resulting in 1 non-zero measurement (0.23%). Note: The non-zero measurement was a made on a compressor (Station 744, Compressor 1202).

These measurements validated that OGI was detecting measurable emissions nearly 100% of the time on these key component categories. Therefore, after July 26th, OGI non-detects in these categories were not generally measured. Table S3-8 summarizes all measurements in this category. Note that some unmeasured OGI non-detects are included in the field data tables where field comments or other information were collected and deemed useful to subsequent practitioners. These measurements are summarized in Table S3-8.

Table S3-8: Measurements where no Emissions were Detected with OGI

Measurement Location	Count of OGI Detections		Fraction Non-Zero
	No Emissions Measured	Non-Zero Emissions Measured)	
Blowdown Vent	68	0	0%
Common Multi-Unit Vent	2	0	0%
Common Single-Unit Vent	39	0	0%
Common Station Vent	1	0	0%
Connector Threaded	1	0	0%
OEL	1	0	0%
PRV	199	0	0%
Pocket Vent	1	0	0%
Rod Packing Vent	56	1	1.8%
Starter Vent	32	0	0%
Thief Hatch	25	0	0%
Valve	3	0	0%
Total	428	1	0.23%

In 88 cases, or 7.8% of all emission locations, an OGI detect was followed by one or more measurement attempts that all indicated zero emissions. Two cases are possible: First, the emission rate may be below the lower detection limit of the measurement instrument. Second, the emission rate may have changed between the OGI detect and the attempted measurement. Counts of these measurements are summarized in Table S3-9. Locations where more than 10% of measurements returned zero are noted as bold text in the table.

Table S3-9: OGI Detections with Zero Measurements

Measurement Location	Total Measurements	Number of Zero Measurements	Zero Fraction
Compressor Blowdown Vent	29	2	6.9%
Compressor Common Multi-Unit Vent	13	2	15%
Compressor Common Single-Unit Vent	23	0	0%
Compressor Connector Flanged	39	2	5.1%
Compressor Connector Threaded	98	9	9.2%
Compressor Other	23	2	8.7%
Compressor PRV	33	5	15%
Compressor Pocket Vent	19	1	5.3%
Compressor Regulator	34	1	2.9%
Compressor Rod Packing Vent	352	8	2.3%
Compressor Starter Vent	20	3	15%
Compressor Valve	37	2	5.4%
Non-compressor Common Station Vent	6	0	0%
Non-compressor Connector Flanged	25	1	4%
Non-compressor Connector Threaded	71	6	8.5%
Non-compressor OEL	23	3	13%
Non-compressor Other	13	0	0%
Non-compressor PRV	20	9	45%
Non-compressor Pump	11	0	0%
Non-compressor Regulator	37	3	8.1%
Non-compressor Valve	86	22	26%
Tank Common Multi-Unit Vent	14	0	0%
Tank Common Single-Unit Vent	42	5	12%
Tank Thief Hatch	65	2	3.1%
Total	1133	88	7.8%

S3-1.7 Gas Types and Units

All measurement equipment quantified whole gas emission rates, which were later corrected by temperature and barometric pressure to standard conditions of 60 °F and one atmosphere and are presented in *standard cubic feet per hour*, (scfh).

Station gas composition was utilized to estimate the methane emission rate. Since gas composition varies within a station, whole gas emission factors are recommended for vented and fugitive emissions when using leaker, average, and major equipment emission factors. For methane emissions, the conversion from scfh to mass flow units is 19.2 g/scf.

Throughout this analysis, gas types are identified by coded names:

Value	Description
WholeGas	Emission rate is in mass flow of the entire gas stream, uncorrected for composition.
CH4	Methane-only fraction of the emission rate, using the appropriate gas compositions.

S3-1.8 Comparison Emission Factors

Emission factors developed here are compared with emissions factors utilized by the Greenhouse Gas Reporting Program (GHGRP), which in turn are derived from a 1996 GRI/EPA study [11] of methane emissions in the oil and gas supply chain. The GRI/EPA focused on well sites; at the time gathering and boosting (G&B) was not considered as a separate supply chain segment. (The GRI/EPA study recognized the following supply chain segments: Onshore Production, Offshore Production, Gas Processing, Transmission, Storage, and Customer Meter Sets.)

Emission factors were developed from measurements on 12 eastern, and 13 western production (i.e. well) sites. The study surveyed 1 well site with gathering compressors in the eastern area (2 compressors), and 13 well sites with gathering compressors in the western U.S. (61 compressors). Gathering compressors hosted on well sites such as those likely visited by the measurement teams during the GRI/EPA study, are typically smaller than those surveyed in this study.

The GRI/EPA study utilized a flame ionization detector (FID) to screen for leaks (this study used OGI) and used one of two methods to quantify emissions:

1. Apply EPA's correlation equation [12] to estimate the emission rate based on concentration measured by the FID.
2. Quantify with high flow method, similar to the approach utilized in this study.

The GRI/EPA study gathered component counts by major equipment at each site visited using a method similar to this study (see Table S3-10). Average factors for the equipment sample are tabulated in Table S3-11.

To calculate national activity factors, the study estimated 129 small gathering compressors in the Eastern US, none at G&B stations (all were estimated to be at well sites, a type of compressor *not* included in this study). In the Western US, the study estimated 16,915 small gathering compressors (found on well sites), and 96 large gathering compressors on 12 large G&B stations.

Table S3-10: EPA/GRI Volume 8, Table 1: Default Average Component Counts for Major Onshore Natural Gas Production Equipment and Onshore Petroleum and Natural Gas Gathering and Boosting Equipment¹

Major Equipment	Valves	Connectors	Open-ended Lines	Pressure Relief Valves	Compressor Seals
Eastern U.S.					
Wellheads	8	38	0.5	0	
Separators	1	6	0	0	
Meters/piping	12	45	0	0	
Gathering Compressors	12	57	0	0	Not reported
In-line heaters	14	65	2	1	
Dehydrators	24	90	2	2	
Western U.S.²					
Wellheads	11 (30%)	36 (20%)	1 (28%)	0	0
Separators	34 (44%)	106 (38%)	6 (94%)	2 (68%)	0
Meters/piping	14 (31%)	51 (47%)	1 (113%)	1 (150%)	0
Gathering Compressors	73 (102%)	179 (51%)	3 (50%)	4 (84%)	4 (69%)
In-line heaters	14 (49%)	65 (70%)	2 (66%)	1 (89%)	0
Dehydrators	24 (31%)	90 (37%)	2 (69%)	2 (53%)	0

¹ [13, Table 1]² Values in parentheses represent the 90% confidence interval. Confidence intervals were not reported for Eastern U.S. component counts.**Table S3-11:** EPA/GRI Volume 8, Table 2: Average Component Emission Factors¹

Component Type	Total Count of Components Screened	Component Emission Factor (scfh CH_4)	Component Emission Factor (scfh whole gas)	Confidence Interval ² (CH_4)
Eastern U.S.				
Valves	4,200	0.021	0.027	29%
Connectors	18,639	0.003	0.004	20%
Open-ended Lines	260	0.048	0.062	54%
Pressure Relief Valves	92	0.032	0.041	88%
Western U.S.				
Valves	6,059	0.095	0.122	10%
Connectors	32,513	0.013	0.017	9%
Open-ended Lines	1,051	0.025	0.032	33%
Pressure Relief Valves	448	0.152	0.195	37%
Compressor Seals	40	0.271	0.347	72%

¹ [13, Table 2].² Confidence interval provided for methane emission factors but not for whole gas factors.

Comparison factors for major equipment emission factors are taken from EPG GHGRP and EPA GHGI, and are shown in Table S3-12.

Table S3-12: Comparison Factors for Major Equipment Units

Equipment Type	EPA GHGI 2016 ¹		EPA GHGRP 2017 (East) ²		EPA GHGRP 2017 (West) ³	
	Whole Gas (scfh whole gas)	Methane (scfh CH ₄)	Whole Gas (scfh whole gas)	Methane (scfh CH ₄) ³	Whole Gas (scfh whole gas)	Methane (scfh CH ₄) ³
Compressors	14.5	11.9	0.5	0.41	12.7	9.83
Dehydrators	3.41	2.80	1.1	0.91	4.87	3.69
Separators	2.84	2.33	0.05	0.04	6.49	5.01
Meters & Piping ⁴	1.50	1.23	0.46	0.38	2.78	2.12
In-line Heaters	1.77	1.46	0.73	0.60	3.05	2.34

¹ GHGI emission factors are from April, 2018, Table 3.6-2 for wellpad equipment[14, Table 3.6-2].

² EPA GHGRP emission factors taken from *Subpart W Calculation Tool for RY16 and Later.xlsx*, sheet '(r) Population Factors-4'[15].

³ Whole gas emission factors are converted to methane using an average methane fraction of 0.821 from GHGI Table 3.6-3.

⁴ Activity data for the meters/piping emission factor is the number of meters in the facility, as per U.S. Code of Federal Regulations 98.233(r)(2)(i)(A).

Leaker emission factors computed here are also compared with measurements from a study of transmission and storage stations. Data used for comparison is the “CDFMaster.xlsx” data file from Zimmerle et. al [16], using only measurements taken from transmission stations. Comparison data is summarized in Table S3-13. For emissions from open-ended lines (“OEL”), measurements from compressor and non-compressor tables were combined into one emission factor. To convert from methane to whole gas, the paper assumes a methane mass fraction of 0.95.

Table S3-13: Whole gas leaker emission factors from transmission and storage study

Leaker Emission Factor	Sheet in T&S Data File	Measurement Count	Emission Factor (scfh Whole gas)
Compressor Connector Flanged	CC Connector	145	21.2 [0.07 to 120]
Compressor Connector Threaded	CC Connector	145	21.2 [0.07 to 120]
Compressor Valve	CC Valve	139	12.2 [0.564 to 86.8]
Compressor PRV	Other	93	22.6 [0.585 to 298]
Non-compressor PRV	Other	93	22.6 [0.585 to 298]
All Other	Other	93	22.6 [0.585 to 298]
Non-compressor Connector Flanged	NC Connector	218	9.87 [0.0616 to 58.4]
Non-compressor Valve	NC Valve	134	12 [0 to 56.3]
Non-compressor Connector Threaded	NC Valve	134	12 [0 to 56.3]
Compressor Rod Packing Vent	RecipRodPack_OP	34	219 [0 to 1.81×10^3]
Compressor Blowdown Vent	BD_ALL	379	76.4 [0 to 494]
All OEL	CC OEL and NC OEL	153	143 [0 to 1.71×10^3]

¹ Activity factor from GHGRP for eastern and western regions.

S3-2 Component Leaker Emission Factors

Leaker emission factors for component categories, represent the distribution of emission rates expected from a source category when emissions are detected during an OGI screen or using a similar screening method. In general, leaker factors are utilized by screening equipment with a leak detection method, and each detected leak is estimated using the appropriate leaker emission factor.

For some component categories, choices must be made on how to group measurements into emission factors. Sections S3-2.1-S3-2.3 discuss key categories where grouping decisions were made. To compare sub-categories of an emission factor, we utilized 2-sample Kolmogorov-Smirnov test (MatLab `kstest2()`) with a statistical significance of 0.95 to detect differences between sub-categories of emissions. For example, one might test whether a valve has the same leak rate on dehydrators as in yard piping.

S3-2.1 Tank Vent Emission Factor Categories

This section describes the development of emissions factors for atmospheric tanks. For the 180 stations in the field campaign, 168 stations had one or more atmospheric-pressure tanks on the station. A total of 403 atmospheric tanks were identified in the field campaign, and 251 were screened and measured. The remaining 12 stations had no tanks.

Measurements were made on two tank locations – thief hatches and other vents (commonly called *Enardo* valves, a type of pressure relief valve or “PRV”). In some cases, measurements were taken on vents attached to a common header across multiple tanks.

This study identifies three source locations for tank emissions:

Thief Hatch: Large access port, typically on the top of the tank. Most thief hatches are equipped with a hatch cover that will open if pressure in the tank exceeds a preset limit. On some tanks, thief hatch may indicate an open hole in the top of the tank with no cover. The number of thief hatches per tank was not counted during the field campaign. Although it is common to have only one thief hatch per tank, 4 tanks measured in the field campaign had more than one measurement per tank, indicating the presence of more than one thief hatch.

Common Single-Unit Vent: A vent location, likely equipped with one or more pressure relief valves, that combines one or more openings in the tank, typically not including the thief hatch. While vent configurations vary widely, it is not unusual that multiple ports or vents in a tank will be combined into a header and routed to atmosphere through a single open-ended line. Common single-tank vents were not counted during the field campaign. However, tanks typically have ports in addition to a thief hatch, and it is reasonable to assume at least one single-tank vent per tank, although some may be plumbed together with vents from other tanks into a common multi-tank vent.

Common Multi-Unit Vent: A vent location that combines vents from multiple tanks into a single emission location. Vent locations are similar to those in the common single-unit vent. Common multi-tank vents were not counted during the field campaign, and the number of such vents and the ports connected to each is difficult to estimate.

Due to their configuration, safely accessing tank emission locations may be difficult if significant emissions are present. During the field campaign, 85 measurements were attempted, and 68 attempts resulted in successful measurements (80%). Of the 50 measurements of common single-tank vents attempted, 84% were successful. As with other sources, successful measurements are utilized in emission factors and estimates are utilized where sources were identified but could not be measured.

Comparing emission sources from individual tanks, both thief hatches and common single tank vents exhibit a similar emission distribution. However, since the activity data for each location is different, and since sufficient data exists for two strong emission factors, both leaker emission factors are provided. Multi-tank vents are significantly larger than single tank vents, warranting separate emission factors. Unfortunately, the number of measurements for multi-tank vents is small, leading to increased uncertainty for that emission factor.

S3-2.2 Compressor Vent Categories and Operating Modes

This section considers how to group emissions measurements for compressors into emission factors, considering the operating state of the compressor, the type of compressor, and the type of compressor driver. In particular, it considers whether separate emission factors are needed – and can be provided – for different operating modes.

Figure S3-10 provides a visual depiction of the common compressor sources on a cutaway view of a single compressor cylinder, and defines principal components of the cylinder. The handling of rod packing vents (RPVs) varies between compressor installations. In some installations, RPVs are connected to a single header and routed to a vent location. In others, RPVs are vented individually at the compressor or through short lengths of tubing. Since emissions from the dog house originate with emissions through rod packing, emissions from dog house vents are included in rod packing emissions. The pocket, and associated pocket vent, sets the compression ratio of the compressor cylinder. While rod packing is designed to emit in regular operation, the pocket vent should not have emissions during normal operation.

Compressors may be in three operating states or *modes*:

Abbreviation	Description
NOP	Pressurized but not operating (“not operating pressurized”)
NOD	Depressurized and not operating (“not operating depressurized”)
OP	Pressurized and operating (“operating”)

Similarly to other measurement campaigns [17, 18], most compressors were operating when measured during this field campaign. During the campaign, field teams screened 465 compressors utilizing OGI and measured 454 compressors, some of which had no OGI detect and no emissions measured. OGI detect occurred on 319 compressor units and was measured using high-flow or bag methods. Of the measured compressors, 83% of the compressors were operating at the time of measurement, and 87% of compressor-related measurements were made while the compressor was operating. (See Tables S3-14 and S3-15)

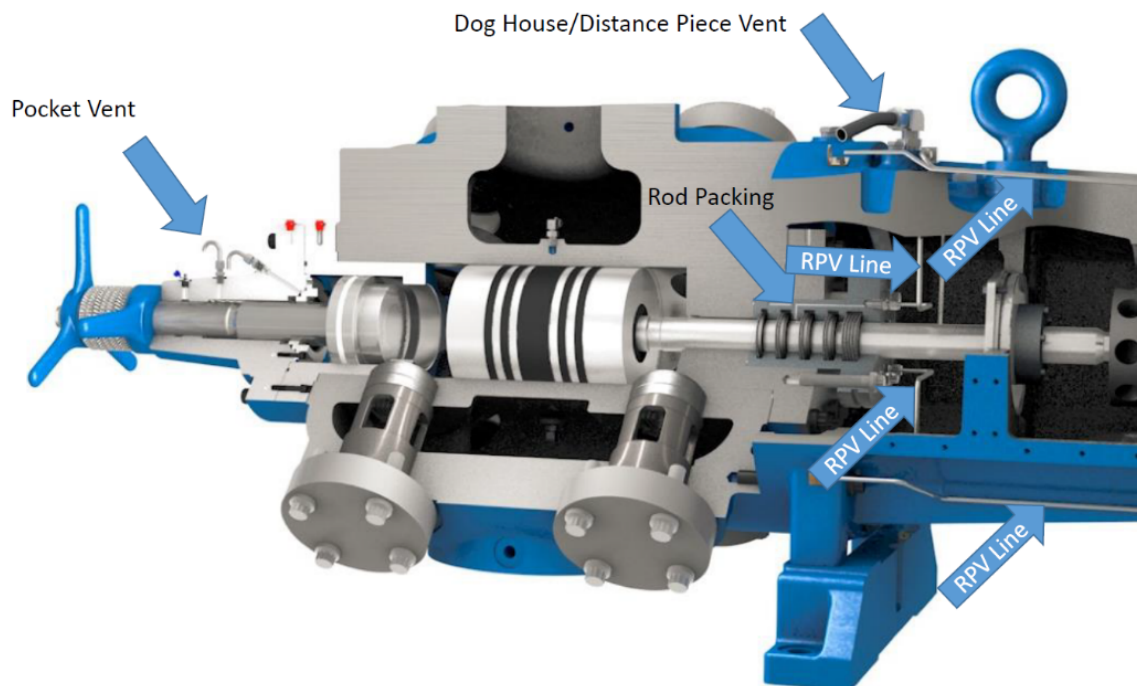


Figure S3-10: Components of compressor cylinder. RPV refers to *rod packing vent*, the vent location for gas which is emitted through the *rod packing seal*. When operating, rod packing vents are expected to emit some gas. The *dog house*, or *distance piece*, contains the straight section of the cylinder rod between the rod packing housing and the crank case of the compressor (not shown). For this study, emissions from dog house vents are considered to rod packing emissions, as the gas has passed through the rod packing and into the dog house area. The pocket vent allows gas to be pushed out of the cylinder when adjusting the compression ratio of the cylinder; in normal operation the pocket vent should not emit any gas.

Image: <https://www.arielcorp.com/Technical-Papers/Compressor-Emissions-Reduction-Technology/>

Table S3-14: Compressor Operating Mode Summary for Measured Compressors

Compressor Type	Operating Mode			Total	Fraction
	NOD	NOP	OP		
Centrifugal	5	2	7	14	3.1%
Reciprocating	31	36	336	403	89%
Screw	2	0	35	37	8.1%
Total	38	38	378	454	100%
<i>Fraction</i>	8.4%	8.4%	83%	100%	

Table S3-15: Count of Measurements Made on Compressors, by Operating Mode

Measurement Type	Operating Mode				Total	Fraction
	NA	NOD	NOP	OP		
Component	0	5	17	264	286	36%
Vent	41	14	27	431	513	64%
Total	41	19	44	695	799	100%
<i>Fraction</i>	5.1%	2.4%	5.5%	87%	100%	

Due to the small number of both units and measurements in NOD and NOP modes, all emission factors are calculated utilizing all measurements in all modes to create emission factors which are not mode-specific. This method effectively combines all operating modes into one emission factor, which is representative of aggregate emissions, provided it is applied to fleets of gathering compressors which have similar, high, utilization rates, as the rates seen in this study.

Notwithstanding the above, it should be noted that for sources where some emission measurements were made in NOP and NOD modes, significant differences were seen relative to operating mode measurements. Examples are provided in Tables S3-16 and S3-17 for two common compressor vents. Therefore, if future data suggests a change in compressor utilization patterns, additional measurements should be made in those NOD and NOP modes to develop separate emission factors. (*KS Test* in the table indicates results of a *Kolmogorov-Smirnoff 2-sided test of similarity*, at the 95% confidence level.)

Table S3-16: Measurement Comparison by Operating Mode for Blowdown Vent

Category	Sub-Category	Count	KS Test	Min	Mean	Max	Mean Ratio	Bootstrap CI
Blowdown Vent		30		0.136	10.8	103		0.14 to 82.76
Blowdown Vent	NOD	3	Passed	3.75	41.4	103	3.81	3.75 to 102.85
Blowdown Vent	NOP	7	Passed	0.166	6.77	22.5	0.62	0.17 to 22.47
Blowdown Vent	OP	20	Passed	0.136	7.7	22.3	0.71	0.14 to 22.26

Table S3-17: Measurement Comparison by Operating Mode for Rod Packing Vent

Category	Sub-Category	Count	KS Test	Min	Mean	Max	Mean Ratio	Bootstrap CI
Rod Packing Vent		393		0.111	23.6	717		0.14 to 163.99
Rod Packing Vent	NOD	7	Passed	4.21	11.5	21.3	0.49	4.21 to 21.28
Rod Packing Vent	NOP	17	Passed	0.115	23.1	113	0.98	0.12 to 113.20
Rod Packing Vent	OP	369	Passed	0.111	23.9	717	1.01	0.14 to 167.94

As shown in Table S3-18, 89% of compressors are of the reciprocating type, followed by screw compressors (8.1%) and a small number of centrifugal compressors (3.1%). 93% of reciprocating compressors are driven by reciprocating engines, typically 4-stroke lean- or rich-burn engines, as shown in Table S3-19. Other compressor types are more often driven by electric or turbine drives. As with the operating mode, few measurements were made on centrifugal or screw compressors (about 4.1%). Therefore, only one emission factor is developed, including all compressor types, and – as with the discussion on operating mode – the result should be applicable provided the mix of compressors does not change substantially from the mix seen in this study.

Table S3-18: Compressor Driver Type by Compressor Type for Measured Compressors

Compressor Driver	Compressor Type			Total	Fraction
	Centrifugal	Reciprocating	Screw		
Electric Motor	0	1	12	13	2.9%
Reciprocating Engine	6	402	25	433	95%
Turbine	8	0	0	8	1.8%
Total	14	403	37	454	100%
<i>Fraction</i>	3.1%	89%	8.1%	100%	

Compressor are equipped with several vent locations designed to emit gas during certain compressor operations. For example, a blowdown vent is utilized to depressurize a compressor, typically to release pressurized gas in the compressor to atmosphere. When not being utilized to depressurize

Table S3-19: Compressor Driver Type Summary for Measured Compressors

Compressor Driver	Operating Mode			Total	Fraction
	NOD	NOP	OP		
4-Stroke Lean Burn	18	22	260	300	<i>66%</i>
4-Stroke Rich Burn	17	15	101	133	<i>29%</i>
Electric Motor	0	0	13	13	<i>2.9%</i>
Turbine	3	1	4	8	<i>1.8%</i>
Total	38	38	378	454	<i>100%</i>
<i>Fraction</i>	<i>8.4%</i>	<i>8.4%</i>	<i>83%</i>	<i>100%</i>	

a compressor, a blowdown vent should emit no gas and any observed emissions are due to leakage through the blowdown valve. In this study emissions blowdown vents, starter vents and pocket vents were not measured during defined venting operations. Therefore emissions reported from these three categories in this study are leaks.

In contrast, when the compressor is operating, rod packing seals are designed to emit some gas, and any observed emissions are technically *venting*, i.e. planned emissions, although on some compressors, rod packing may be emitting more than the manufacturer's specifications. When the compressor is not operating (NOP or NOD modes), emissions should be zero, and any measured emissions are considered leaks.

Comparing the four compressor vent locations encountered during the field study, we find that a separate emission factor is required for each vent location, but insufficient data exists to split emission factors by *both* vent type and operating mode. Therefore separate emission factors are developed for each vent location.

S3-2.3 Component Categories for Flanged and Threaded Connectors

During the field campaign, connectors were classified as flanged or threaded connectors. The comparisons of leaker emission factors (whole gas), below, indicates that all connectors on compressor equipment have statistically similar emissions (Figure S3-11), while connectors on non-compressor equipment have statistically different emissions (Figure S3-12). No explanation of this behavior is available. For consistency, emission factors are separated by connector type for both compressor and non-compressor equipment.

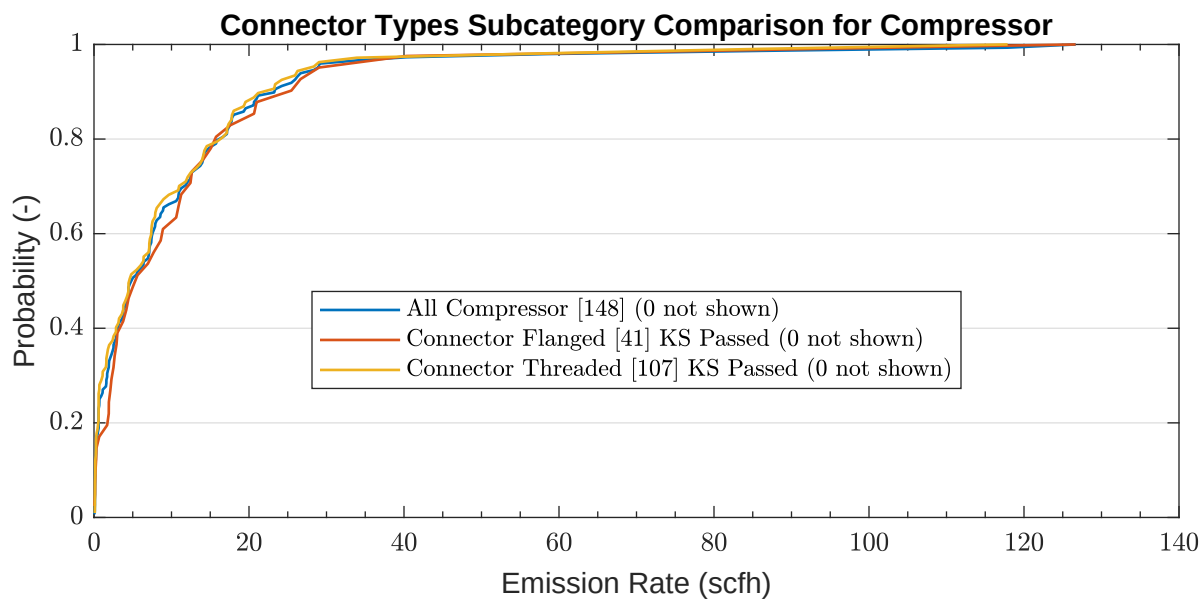


Figure S3-11: Connector Types Subcategory Comparison for Compressor

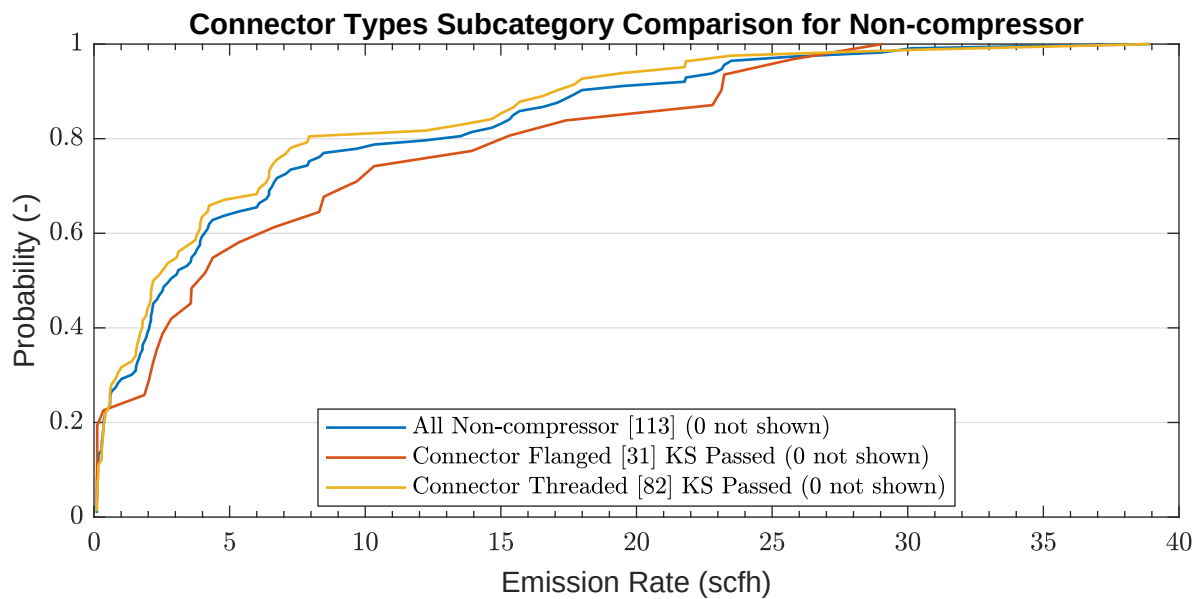


Figure S3-12: Connector Types Subcategory Comparison for Non-compressor

S3-2.4 Use of Measurement Quality Indicators in Leaker Emission Factors

Table S3-20 summarizes the use of measurement quality indicators in development of leaker emission factors. Measurement quality indicators which were not included in leaker emission factors were excluded for one or both of two factors: First, insufficient information existed to estimate emissions for any given emission point. Second, for these categories, there is no indication that the unmeasured emissions were unrepresented by measurements that *were* completed – i.e. there is no evidence they were systematically higher or lower than other successful measurements. In practice, detected emissions which were successfully measured (measurement quality indicator of “Measured”) and measurement attempts with “Incomplete Capture” were included in the leaker emission factors.

Table S3-20: Measurement Quality Indicators For Leaker Factors

Measurement Quality Indicator	Included in Leaker Emission Factor	Measurement Made (possibly incomplete) ³	Estimated Emissions Included in Leaker Emission Factor
Measured	✓	✓	✗
Incomplete Capture	✓	✓ ¹	✓
Exceeded Capacity	✗	✗	✗ ⁴
Inaccessible	✗	✗	✗
Safety	✗	✗	✗
Cannot Measure	✗	✗	✗
Weather	✗	✗	✗
Other	✗	✗	✗
OGI Non-detect ²	N/A	N/A	N/A
Multi-component vents	✓ ⁵	✓	✗

¹ Field teams estimated the fraction of emissions captured in 11 of 23 measurements. Mean fraction estimated, and range of estimates, is 56% [30% to 90%].

² Some measurements of vents were made prior to July 26th for vents with no OGI emissions detection. These measurements are not included in leaker factors since leaker factors are only applicable for emission points with OGI detections.

³ Incomplete measurements are classified as *Incomplete Capture*. See description in text.

⁴ *Exceeded Capacity* measurements are included in major equipment emission factors but not in leaker or population emission factors.

⁵ Separate emission factors are developed for multi-component emission locations, separate from single-component emission locations.

In a few cases, attempts to measure emissions exceeded the capacity of the measurement equipment. Including these large emitters in leaker emission factors tends to distort individual factors. For example, one “Exceeded Capacity” measurement occurred on compressor flanged connectors but zero on compressor threaded connectors, while for non-compressor connectors, it situation was reversed. Therefore, all “Exceeded Capacity” measurements are excluded from leaker emission factors but are included in emission factors for major equipment (Section S3-4).

S3-2.5 Estimation of “Incomplete Capture” Measurements

For “Incomplete Capture”, emissions are estimated from the measured value divided by the fraction captured when noted by the observer with an OGI camera who watched the measurement. Where field notes do not indicate a fraction captured, the fraction is estimated using bootstrap methods from the distribution of all such estimates made during the field campaign. A histogram of these estimates is shown in Figure S3-13. The mean value of these estimates is 56% [41% to 73%] indicating that, on average, actual emissions were approximately twice the measured value. The impact of this adjustment is tabulated in Table S3-21. All measurement records for incomplete capture as summarized in data table *D7 IncompleteCaptures*.

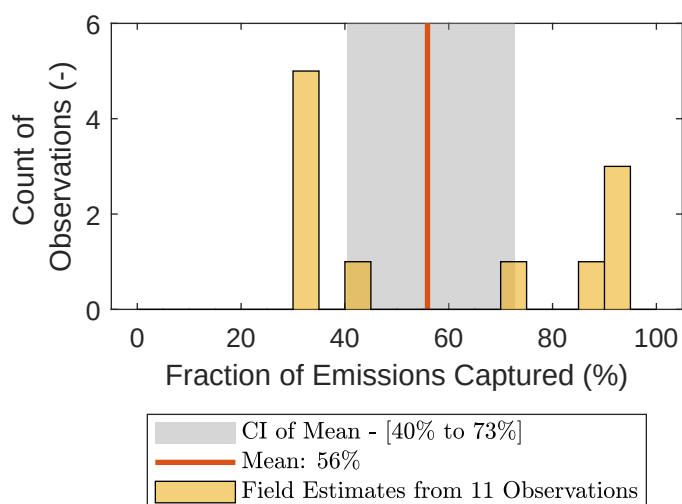


Figure S3-13: Estimated Fraction of Emissions Captured For Incomplete Capture

Table S3-21: Impact of Incomplete Capture Adjustment on Leaker Emission Factors

Category ¹	Without Adjustments	With Adjustments	Relative Difference In Mean
Compressor Blowdown Vent	10.8	21.1	95% [38% to 228%]
Station Common Station Vent	53	85.3	62% [41% to 104%]
All Pump	23.3	35.5	51% [21% to 101%]
Tank Common Single-Unit Vent	32.6	48.3	49% [26% to 101%]
Compressor Connector Threaded	9.83	14.6	49% [30% to 83%]
Compressor PRV	16.2	21.3	31% [14% to 75%]
Compressor Rod Packing Vent	23.8	28	18% [11% to 41%]
Compressor Valve	37.4	41.2	10% [6.2% to 18%]
All Other	23.2	24.1	3.3% [3.1% to 3.7%]
Compressor Connector Flanged	11.9	12.2	2.4% [1.9% to 3%]
Non-compressor Connector Flanged	8.07	7.9	-1.9% [-2.2% to -1.6%]

¹ Categories with more than 1% change shown

S3-2.6 Leaker Emission Factor Tables

Table S3-23 compares emission factors developed here to GHGRP emission factors and to similar emission factors for transmission [16] for those categories that have comparable emission factors. Abbreviations used in the table are:

- *Comp* - indicates emission factors for component in compressor service.
- *NC* - indicates non-compressor service.
- *Reg.* - abbreviates “regulator”.
- *Conn.* - abbreviates “connector”.

The complete set of leaker emission factors for whole gas are summarized in Table S3-24 and data table *D21 Leaker Whole Gas EF*. Component categories where there were less than 15 measurements are indicated by italics in the tables, and should be utilized with caution. Appendix B contains detailed plots and activity data tables for all leaker emission factors.

In addition to the component categories in the tables, no leaks were detected on 2 component categories, although a substantial number of components in each category were counted during the field campaign. No emission factors are possible for this set of components, although screening results indicate emissions are lower than other categories with detected and measured emissions. A summary of the component counts are in Table S3-22. Note that a full list of component counts, by major equipment type, is included in the *DataTable.xlsx*.

Table S3-22: Component Categories with No OGI Detections or Measurements

Component Category	Number of Components Counted
Gauge	1859
Meter	618

Table S3-23: Component Leaker Factor Comparison

Component ¹	Emission Factor (scfh whole gas)	GHGRP ² Emission Factor	Ratio Study to GHGRP	Transmission ³ Emission Factor	Ratio Study to Transmission
All OEL	5.58 [+67%/-51%]	2.8	1.99	143 [+1093%/-100%]	0.044 [0.016 to 0.1]
All Other	24 [+67%/-49%]			22.6 [+1218%/-97%]	1.1 [0.43 to 2.5]
Comp Blowdown Vent	21.3 [+150%/-70%]			76.4 [+546%/-100%]	0.15 [0.066 to 0.28]
Comp Conn. Flange	12.2 [+57%/-40%]	4.1	2.98	21.2 [+465%/-100%]	0.77 [0.21 to 2]
NC Conn. Flange	7.88 [+42%/-36%]	4.1	1.92	9.87 [+491%/-99%]	0.84 [0.47 to 1.4]
Comp Conn. Thread	14.5 [+52%/-38%]	1.3	11.2	21.2 [+465%/-100%]	0.64 [0.19 to 1.5]
NC Conn. Thread	5.77 [+31%/-28%]	1.3	4.44	12 [+368%/-100%]	0.5 [0.29 to 0.78]
Comp PRV	21.2 [+82%/-57%]	4.5	4.71	22.6 [+1218%/-97%]	0.8 [0.29 to 1.8]
NC PRV	10.8 [+123%/-80%]	4.5	2.41	22.6 [+1218%/-97%]	0.53 [0.092 to 1.4]
Comp Reg.	13.9 [+38%/-32%]	4.5	3.09		
NC Reg.	8.01 [+33%/-30%]	4.5	1.78		
Comp Rod Packing Vent	28.2 [+37%/-24%]			219 [+728%/-100%]	0.12 [0.059 to 0.23]
Comp Valve	41.1 [+109%/-64%]	4.9	8.39	12.2 [+613%/-95%]	3.3 [0.91 to 8.2]
NC Valve	7.89 [+46%/-37%]	4.9	1.61	12 [+368%/-100%]	0.68 [0.38 to 1.1]

¹ Abbreviations: “Comp” = Compressor service; “NC” = non-compressor service; “Conn.” = connector; “Reg.” = regulator.

² [?, Table W-1E]

³ [16, Data File CDFMaster.xlsx]

Table S3-24: Whole Gas Leaker Emission Factors

Component	Number Measured	Number Simulated	Emission Factor (scfh whole gas)	Confidence Interval (scfh whole gas)	Fraction of Emissions Due to Largest 5% of Emitters
Non-compressor service					
Connector Flanged	31	1	7.88	[+42%/-36%]	18%
Connector Threaded	82	0	5.77	[+31%/-28%]	25%
PRV	23	0	10.8	[+123%/-80%]	54%
Regulator	43	0	8.01	[+33%/-30%]	18%
Valve	99	0	7.89	[+46%/-37%]	38%
Compressor service					
Connector Flanged	41	1	12.2	[+57%/-40%]	33%
Connector Threaded	107	5	14.5	[+52%/-38%]	47%
PRV	35	1	21.2	[+82%/-57%]	43%
Regulator	37	0	13.9	[+38%/-32%]	21%
Valve	39	1	41.1	[+109%/-64%]	58%
Common Multi-Unit Vent	13	0	66	[+86%/-71%]	
Common Single-Unit Vent	23	0	76	[+52%/-45%]	20%
Blowdown Vent	30	1	21.3	[+150%/-70%]	59%
Pocket Vent	23	0	7.81	[+80%/-61%]	34%
Rod Packing Vent	390	7	28.2	[+37%/-24%]	46%
Starter Vent	21	0	296	[+193%/-96%]	86%
Rod Packing Vent (OP)	366	7	28.5	[+35%/-24%]	47%
Rod Packing Vent (NOP)	17	0	23	[+65%/-49%]	
Rod Packing Vent (NOD)	7	0	11.5	[+42%/-37%]	
Tank service					
Common Multi-Unit Vent	15	0	119	[+90%/-68%]	
Common Single-Unit Vent	42	2	48.4	[+86%/-58%]	45%
Thief Hatch	65	0	30.1	[+54%/-41%]	41%
Other					
OEL	23	0	5.58	[+67%/-51%]	31%
Other	42	1	24	[+67%/-49%]	44%
Pump	12	2	35.5	[+74%/-53%]	

S3-3 Component Average Activity and Emission Factors

Average emission factors (also known as *population* emission factors) provide distributions of emissions for a population of components. Average factors are typically utilized by counting all components within a population and multiplying the count of components with the appropriate emission factor. Unlike leaker factors, Section S3-2, no screening for leaks is required.

S3-3.1 Methodology for Average Emission Factors

This section describes the methods utilized to develop average emission factors. The same calculation method is also utilized to develop major equipment emission factors, Section S3-4.

During the field campaign, major equipment units (Table S3-25) were screened utilizing optical

gas imaging (OGI). Average emission factors are calculated by (1) adding estimates or measurements for all detected emissions, (2) estimating the total number of components screened – the *activity basis* for the emission factor, and (3) dividing the emissions estimate by the activity estimate. The emission estimate must include an estimate for all detected emissions, and the activity estimate must include an estimate for all components screened.

Components were counted on a subset of major equipment. Considering one component category c there is a set $\{n_{c,e}\}$ containing $N_{c,e}$ units of major equipment of type e for which components were counted, producing a distribution of component counts for that type of major equipment, $D_{c,e}$, where each element of the distribution is the count on one piece of major equipment.

There is also a set $\{m_{c,e}\}$ containing $M_{c,e}$ units of major equipment which were screened and measured. These units may or may not have been subjected to component counts. Any OGI detections on the screened units are noted, producing a set of $\{E_{c,e}\}$ emission detections. As per the discussion of quality indicators (Section S3-1.6), some, but not all detections were successfully measured. For population (and major equipment) emission factors, we estimate all detected but unmeasured emissions except for the large emitter quality indicator, as described in Section S3-3.2. Therefore $\{E\}$ has a non-zero estimate for all detected emissions. Other screened components, where there was no OGI detect, are assumed to have zero emissions, following common practice for development of population emission factors.

To develop an component count estimate for emission factor f_c , we cycle through the $\{m_{c,e}\}$ pieces of major equipment which were screened and measured for the emission factor and estimate a component count for each. Since not all measured equipment was counted, this includes two terms – actual component counts when available, ($\{\hat{n}_{c,e}\} = \{m_{c,e}\} \cap \{n_{c,e}\}$), and estimated component counts when not available. The component count estimate is:

$$D_c^{(j)} = \sum_{e \in f} \left[\sum_{e \in \{\hat{n}_{c,e}\}} D_{c,e} + \sum_{i=\hat{N}_{c,e}+1}^{M_{c,e}} \text{draw}(D_{c,e}) \right] : j = 1..N_j \quad (1)$$

where the operator $\text{draw}(d)$ draws a sample from distribution d . The sampling operation is completed N_j times to develop a distribution of component counts, $D_c = \{D_c^{(j)} : j = 1..N_j\}$. For this analysis $N_j = 5000$. Distribution D_c represents a component count estimate for all equipment which was screened for component type c and therefore is the total component population for f_c .

Total emissions associated with these components can also be summed, using the same uncertainty models as described for leaker emissions factors in Section S3-2.4:

$$E_c^{(j)} = \sum_{e \in f} \sum_{e \in \{E_{c,e}\}} E_{c,e} : j = 1..N_j \quad (2)$$

where replicates $1..N_j$ account for measurement and estimation uncertainty.

Table S3-25: Major Equipment Types

Type	Total	OGI Screen	Measured
AGRU	14	8	8
Compressor	541	465	435
Dehydrator	154	132	123
Separator	372	336	326
Tank	403	339	251
YardPiping	876	815	805

Finally, the emission factor distribution for the component f_c is:

$$f_c^j = \frac{E_c^{(j)}}{D_c^{(j)}} : j = 1..N_j \quad (3)$$

S3-3.2 Estimation of Detected but Unmeasured Emissions

Average emission factors must include estimates for all detected emissions, since component counts are included for all screened and measured units. Table S3-26 summarizes how each measurement quality indicator was incorporated into simulated emissions. Additional notes:

- When incorporating a measurement into the emission factor, either a completed measurement (column 2 in table) or drawing from a leaker emission factor (column 3 in table), measurement uncertainty is also applied to the emission rate.
- If an “Exceeded Capacity” indicator is encountered on a unit of major equipment, that unit is not included in average emission factor calculation. This guarantees that all detected emissions are included in the average emission factor calculation.
- For the two tank emission categories (thief hatches and common single-unit-vents) and one compressor emission category (common single-unit vents), activity counts were not completed during the field campaign. For these emission factors we assume there is one hatch or vent per unit (tank or compressor). This assumption reduces the component count, and increases the emission factor, in these categories.

For example, of 251 tanks screened and measured in the field campaign, 81 had thief hatch emissions and 4 of those tanks had emissions reported on more than one thief hatch. Assuming the frequency of multiple measurements is approximately equal to the frequency of multiple thief hatches in the total population, the assumption of one thief hatch per tank increases the average emission factor by 4.9%. Using the same analysis, the assumption increases the tank and compressor single unit vent average emission factor by 14% and 3.1%, respectively.

Table S3-26: Measurement Quality Indicator For Average Emission Factors

Measurement Quality Indicator	Measurement Included in Factor	Estimated from Leaker Emission Factor for Component ¹	Estimated using Alternative Algorithm
Measured	✓		
Incomplete Capture			✓ ²
Exceeded Capacity			✗ ³
Inaccessible		✓	
Safety		✓	
Cannot Measure		✓	
Weather		✓	
Other		✓	
OGI Non-detect			✓ ⁴
Single-unit vents			✗ ⁵
Multi-unit vents			✗ ⁵

¹ Estimate made by identifying the component type for each identified emission source, and then drawing an emission rate from the leaker emissions distribution for that component type.

² *Incomplete Capture* emissions are included in average factors using same algorithm as utilized for leaker factors.

³ Emissions for *Exceeded Capacity* are not included in average emission factors, but are included in major equipment emission factors.

⁴ OGI non-detects are included, as are other non-detects, as “no detected emissions” when calculating average emission factors.

⁵ Single-unit vents, which combine emissions from multiple components, and multi-unit vents, which combine emissions from multiple equipment units, are not included in average emission factors, but are included in major equipment emission factors and station estimates.

S3-3.3 Average Emission Factor Results

Table S3-27 summarizes the population (average) emission factors. Columns in the tables are:

Column Header	Description
Category	Emission factor category name.
Activity Basis	Which components were counted to create the average emission factor.
Mean Population	The mean number of units which were screened with OGI during the field had they been emitting.
Emission Factor	Mean value of the emission factor (scfh)
Confidence Interval	Empirical 95% confidence interval taken from the replicates in Eqn. 3 without bootstrapping
GHGRP East & West	Where possible, data is compared with emission factors from the <i>GHGRP</i> . For average factors, GHGRP provides seperate factors for the eastern and western USA, see Section S3-1.8.

Activity factors for all component and major equipment categories are given the data file *D12 Components Per Unit*. Data for emission factors are in the data file *D22 Average Whole Gas EF*. The additional data file *AvgFactor.xlsx* contains detailed data for all average factors, in the form of histograms of the simulated results.

Since many of the average factor distributions are highly skewed, detailed distributions for whole gas average factors are provided in the accompanying data files *AvgFactors.xlsx*.

Table S3-27: Whole Gas Average Emission Factors

Component	Activity Basis	Mean Population	Emission Factor (scfh WholeGas)	Confidence Interval (scfh WholeGas)
Non-compressor service				
Connector Flanged	Counted Components	12,290	0.0213	[+17%/-14%]
Connector Threaded	Counted Components	38,696	0.0127	[+12%/-11%]
PRV	Counted Components	1,067	0.279	[+50%/-22%]
Regulator	Counted Components	608	0.626	[+23%/-19%]
Valve	Counted Components	9,981	0.091	[+28%/-23%]
Compressor service				
Connector Flanged	Counted Components	30,964	0.0186	[+25%/-14%]
Connector Threaded	Counted Components	60,419	0.0308	[+31%/-20%]
PRV	Counted Components	1,698	0.54	[+44%/-25%]
Regulator	Counted Components	658	0.781	[+15%/-14%]
Valve	Counted Components	10,204	0.169	[+38%/-18%]
Common Multi-Unit Vent	One per Station	140	7.2	[+36%/-23%]
Common Single-Unit Vent	One per Compressor	433	4.19	[+22%/-14%]
Blowdown Vent	One per Compressor	416	0.614	[+126%/-22%]
Pocket Vent	Compressor Cylinders	1,506	0.135	[+30%/-17%]
Rod Packing Vent	One per Compressor	412	27.7	[+25%/-11%]
Starter Vent	One per Compressor	426	16.7	[+78%/-31%]
Rod Packing Vent (OP)	One per Compressor	431	25.2	[+25%/-11%]
Rod Packing Vent (NOP)	One per Compressor	435	1.14	[+39%/-28%]
Rod Packing Vent (NOD)	One per Compressor	434	0.15	[+18%/-20%]
Tank service				
Common Multi-Unit Vent	One per Station	127	15.9	[+40%/-27%]
Common Single-Unit Vent	One per Tank	246	5.35	[+33%/-17%]
Thief Hatch	One per Tank	240	8.05	[+9.4%/-9.3%]
Other				
OEL	Counted Components	476	0.294	[+30%/-21%]

Tables S3-28 and S3-29 compare the component average emission factors to emission factors utilized in the GHGRP for whole gas and methane, respectively. Different average emission factors are utilized by the GHGRP for eastern and western regions of the USA, as described in Section S3-1.8.

To compute ratios, the confidence interval provided with GHGRP emission factors was assumed to be a 90% confidence interval on lognormally distributed data with a relative mean of $m = 1.0$ and a relative standard deviation of $s = CI/1.645$, since $z_{\alpha}/2 = 1.645$ for a 90% CI. Since some GHGRP emission factors have high uncertainty (CIs as high as 88%), the ratios are highly uncertain as well.

Table S3-28: Comparison of Whole Gas Average Emission Factors to GHGRP Factors

Category	Emission Factor (scfh)	Eastern Region		Western Region	
		GHGRP EF (scfh)	Ratio of Study to GHGRP EF	GHGRP EF (scfh)	Ratio of Study to GHGRP EF
Compressor Connector Flanged	0.0186 [+25%/-14%]	0.003	6.28 [4.65 to 8.53]	0.017	1.1 [0.902 to 1.4]
Non-compressor Connector Flanged	0.0213 [+17%/-14%]	0.003	7.2 [5.41 to 9.47]	0.017	1.26 [1.04 to 1.5]
Compressor Connector Threaded	0.0308 [+31%/-20%]	0.003	10.4 [7.45 to 14.7]	0.017	1.82 [1.42 to 2.43]
Non-compressor Connector Threaded	0.0127 [+12%/-11%]	0.003	4.3 [3.28 to 5.54]	0.017	0.75 [0.639 to 0.878]
Compressor PRV	0.54 [+44%/-25%]	0.04	17.4 [5.21 to 42.8]	0.193	2.93 [1.63 to 4.95]
Non-compressor PRV	0.279 [+50%/-22%]	0.04	9.01 [2.82 to 22.5]	0.193	1.52 [0.871 to 2.64]
Compressor Valve	0.169 [+38%/-18%]	0.027	6.46 [4.27 to 9.78]	0.121	1.4 [1.1 to 1.95]
Non-compressor Valve	0.091 [+28%/-23%]	0.027	3.48 [2.21 to 5.16]	0.121	0.755 [0.564 to 0.991]
Compressor Rod Packing Vent	27.7 [+25%/-11%]	1.3	21.8 [15.2 to 30.8]	1.3	21.9 [15.3 to 31.2]
All OEL	0.294 [+30%/-21%]	0.061	5.32 [2.6 to 9.76]	0.031	9.92 [6.03 to 15.6]
Compressor Rod Packing Vent (OP)	25.2 [+25%/-11%]	1.3	19.8 [13.9 to 28.3]	1.3	19.8 [13.9 to 28.1]
Compressor Rod Packing Vent (NOP)	1.14 [+39%/-28%]	1.3	0.895 [0.556 to 1.37]	1.3	0.895 [0.558 to 1.4]
Compressor Rod Packing Vent (NOD)	0.15 [+18%/-20%]	1.3	0.119 [0.0814 to 0.165]	1.3	0.118 [0.0807 to 0.167]

Table S3-29: Comparison of Methane Average Emission Factors to GHGRP Factors

Category	Emission Factor (scfh)	Eastern Region		Western Region	
		GHGRP EF (scfh)	Ratio of Study to GHGRP EF	GHGRP EF (scfh)	Ratio of Study to GHGRP EF
Compressor Connector Flanged	0.014 [+23%/-14%]	0.00234	6.04 [4.51 to 8.22]	0.0133	1.06 [0.873 to 1.32]
Non-compressor Connector Flanged	0.0174 [+16%/-14%]	0.00234	7.54 [5.6 to 9.93]	0.0133	1.31 [1.09 to 1.58]
Compressor Connector Threaded	0.0254 [+29%/-19%]	0.00234	11 [7.91 to 15.4]	0.0133	1.92 [1.51 to 2.52]
Non-compressor Connector Threaded	0.0108 [+13%/-11%]	0.00234	4.7 [3.58 to 6.07]	0.0133	0.819 [0.702 to 0.967]
Compressor PRV	0.459 [+51%/-28%]	0.0312	18.9 [5.81 to 46.3]	0.151	3.21 [1.81 to 5.69]
Non-compressor PRV	0.243 [+48%/-22%]	0.0312	10.1 [3.14 to 25.3]	0.151	1.7 [0.959 to 2.94]
Compressor Valve	0.15 [+46%/-18%]	0.0211	7.36 [4.81 to 11.4]	0.0944	1.6 [1.26 to 2.34]
Non-compressor Valve	0.0772 [+28%/-24%]	0.0211	3.78 [2.44 to 5.68]	0.0944	0.821 [0.605 to 1.07]
Compressor Rod Packing Vent	24.3 [+26%/-11%]	1.02	24.5 [17.3 to 35.8]	1.02	24.4 [17 to 35.1]
All OEL	0.238 [+31%/-21%]	0.0476	5.56 [2.64 to 10.5]	0.0242	10.2 [6.35 to 15.9]
Compressor Rod Packing Vent (OP)	22.1 [+25%/-12%]	1.02	22.2 [15.6 to 31.8]	1.02	22.4 [15.4 to 32.3]
Compressor Rod Packing Vent (NOP)	0.988 [+40%/-29%]	1.02	0.997 [0.611 to 1.56]	1.02	0.993 [0.615 to 1.54]
Compressor Rod Packing Vent (NOD)	0.117 [+17%/-22%]	1.02	0.118 [0.0804 to 0.166]	1.02	0.118 [0.0798 to 0.165]

S3-3.4 Component Counts for Average Emission Factors

Component counts (i.e. component activity factors) for each major equipment type are given in Tables S3-30 - S3-35. Where available, activity factors are compared to component counts used in the GHGRP for the Eastern and Western EPA regions.

Table S3-30: Component Counts for AGRU

Component	Activity Basis	Units Counted	Component Count (-)	East ¹ Component Count	Ratio East to Study	West ¹ Component Count	Ratio West to Study
Connector Flanged	Unit	7	53 [+36%/-100%]				
Connector Threaded	Unit	7	128 [+154%/-58%]				
Gauge	Unit	7	6 [+150%/-100%]				
Meter	Unit	7	0.857 [+600%/-100%]				
OEL	Unit	7	0.571 [+425%/-100%]				
PRV	Unit	7	5 [+100%/-40%]				
Pneumatic Controller	Unit	4	0				
Regulator	Unit	7	1 [+600%/-100%]				
Valve	Unit	7	50.1 [+70%/-30%]				

¹ Activity factor from GHGRP for eastern and western regions.

Table S3-31: Component Counts for Compressor

Component	Activity Basis	Units Counted	Component Count (-)	East ¹ Component Count	Ratio East to Study	West ¹ Component Count	Ratio West to Study
Connector ²	Unit	286	211 [+109%/-83%]	57	0.27	179	0.846
Connector Flanged	Unit	286	71.6 [+137%/-97%]				
Connector Threaded	Unit	286	140 [+160%/-80%]				
Gauge	Unit	286	3.31 [+385%/-100%]				
Meter	Unit	286	1.43 [+1923%/-100%]				
OEL	Unit	283	0.622 [+865%/-100%]	0	0	3	4.82
PRV	Unit	286	3.93 [+78%/-100%]	0	0	4	1.02
Pneumatic Controller	Unit	130	3.18 [+57%/-69%]				
Regulator	Unit	286	1.52 [+294%/-100%]				
Valve	Unit	286	23.6 [+133%/-100%]	12	0.508	73	3.09

¹ Activity factor from GHGRP for eastern and western regions.

² Includes both flanged and threaded connectors to compare to GHGRP activity factor.

Table S3-32: Component Counts for Dehydrator

Component	Activity Basis	Units Counted	Component Count (-)	East ¹ Component Count	Ratio East to Study	West ¹ Component Count	Ratio West to Study
Connector ²	Unit	63	149 [+134%/-75%]	90	0.605	90	0.605
Connector Flanged	Unit	63	21.2 [+238%/-100%]				
Connector Threaded	Unit	63	128 [+154%/-85%]				
Gauge	Unit	63	3.9 [+310%/-100%]				
Meter	Unit	63	0.222 [+800%/-100%]				
OEL	Unit	63	0.46 [+552%/-100%]	2	4.34	2	4.34
PRV	Unit	63	2.54 [+133%/-100%]	2	0.788	2	0.788
Pneumatic Controller	Unit	31	3.23 [+176%/-69%]				
Regulator	Unit	63	3.19 [+242%/-100%]				
Valve	Unit	63	23.1 [+155%/-100%]	24	1.04	24	1.04

¹ Activity factor from GHGRP for eastern and western regions.² Includes both flanged and threaded connectors to compare to GHGRP activity factor.**Table S3-33:** Component Counts for Separator

Component	Activity Basis	Units Counted	Component Count (-)	East ¹ Component Count	Ratio East to Study	West ¹ Component Count	Ratio West to Study
Connector ²	Unit	184	47.9 [+284%/-83%]	6	0.125	106	2.21
Connector Flanged	Unit	184	16.6 [+297%/-100%]				
Connector Threaded	Unit	184	31.3 [+285%/-96%]				
Gauge	Unit	184	0.766 [+552%/-100%]				
Meter	Unit	184	0.0598 [+1573%/-100%]				
OEL	Unit	182	0.225 [+788%/-100%]	0	0	6	26.6
PRV	Unit	184	1.2 [+151%/-100%]	0	0	2	1.67
Pneumatic Controller	Unit	80	1.93 [+160%/-48%]				
Regulator	Unit	184	0.25 [+1060%/-100%]				
Valve	Unit	184	11.3 [+217%/-100%]	1	0.0882	34	3

¹ Activity factor from GHGRP for eastern and western regions.² Includes both flanged and threaded connectors to compare to GHGRP activity factor.**Table S3-34:** Component Counts for Tank

Component	Activity Basis	Units Counted	Component Count (-)	East ¹ Component Count	Ratio East to Study	West ¹ Component Count	Ratio West to Study
Connector Flanged	Unit	54	4.44 [+585%/-100%]				
Connector Threaded	Unit	54	35.4 [+382%/-88%]				
Gauge	Unit	54	1.48 [+383%/-100%]				
Meter	Unit	54	0				
OEL	Unit	54	0.278 [+980%/-100%]				
PRV	Unit	54	1.63 [+244%/-100%]				
Pneumatic Controller	Unit	32	0				
Regulator	Unit	54	0.37 [+710%/-100%]				
Valve	Unit	54	5.13 [+829%/-100%]				

¹ Activity factor from GHGRP for eastern and western regions.

Table S3-35: Component Counts for Yard Piping

Component	Activity Basis	Units Counted	Component Count (-)	East ¹ Component Count	Ratio East to Study	West ¹ Component Count	Ratio West to Study
Connector ²	Station	43	266 [+316%/-93%]	45	0.169	51	0.192
Connector Flanged	Station	43	85.7 [+302%/-95%]				
Connector Threaded	Station	43	180 [+333%/-92%]				
Gauge	Station	43	4 [+561%/-100%]				
Meter	Station	43	1.51 [+287%/-100%]				
OEL	Station	42	0.881 [+661%/-100%]	0	0	1	1.14
PRV	Station	43	2.58 [+353%/-100%]	0	0	1	0.387
Pneumatic Controller	Station	17	5.06 [+177%/-100%]				
Regulator	Station	43	2.19 [+396%/-100%]				
Valve	Station	43	61.8 [+317%/-96%]	12	0.194	14	0.227

¹ Activity factor from GHGRP for eastern and western regions.

² Includes both flanged and threaded connectors to compare to GHGRP activity factor.

S3-4 Emission Factors for Major Equipment

This section provides the emission factors for units of major equipment, such as compressors or separators. To develop emission factors, each unit of equipment was identified by its station ID, equipment type, and equipment identifier. For example, station 123 could have a compressor identified as “*station 123, compressor, unit 1*” and a separator identified as “*station 123, separator, unit 1*”. In the data tables, sheet *D9 Equipment*, each unit of major equipment is represented by one line of data.

S3-4.1 Major Equipment Modeling Methods

A unit may have been screened with OGI and may also have been measured. If a unit is marked as screened, the entire unit was screened with an OGI camera, and if a unit is marked as measured, an attempt was made to measure all detected emissions on the unit. To develop emission factors, only units which were both screened and measured are included in the emission factor. For these units, all successful measurements are combined with estimates for all detected but unmeasured sources, using the same process as defined for *component average emission factors*, described in Section S3-3, with the following additions:

Common single-unit vent: these emission locations include emissions that all originate on a single major equipment unit, and all measured emissions are included in the total emissions for that unit.

Common multi-unit vent: these emission locations require additional handling, since these sources include emissions from multiple major equipment units. Multi-unit vents occur on both *compressors* and *tanks*. Emissions from these sources may originate with one, some, or all of the units combined into the multi-unit vent. Therefore, for an individual unit, emissions from one of these sources may range from zero to the 100% of emissions, and it is important to capture this range of uncertainty in the resulting per-unit emission factor(s).

Therefore, to handle multi-unit vents, emissions were first simulated as described in Section S3-3, producing a series of Monte Carlo estimates for the emissions. The emissions were then divided by a random number of “emitting units”, uniformly distributed between zero and the number of units connected to the multi-unit vent. This method replicates the full range of emissions for an individual unit, while assuming that, in the mean, one half of the connected units are responsible for the emissions. For example, if four compressors were connected to a common vent, the algorithm would estimate that, on average, two compressors are responsible for all of the emissions at any given time, with a range of emissions from any one unit from zero to the full emission rate of the multi-unit vent.

Yard piping: When measured during the field campaign yard piping was divided into arbitrary sub-units that were convenient for field teams. Therefore, a single station may have multiple yard piping equipment identifiers, all combining into a single yard piping “unit” for a station. Only stations where *all* yard piping was screened and measured are utilized to develop yard piping emission factors.

Pneumatic controllers: As per standard practice in the GHGRP and GHGI, pneumatic controller emissions *are not* combined into the emissions from major equipment. Instead, the count of pneumatic controllers, and their emissions, are tracked as a separate line item at the *station* for station estimates (see Section S3-5) or the *basin* for national estimates (see Section S3-6).

Exhaust methane: Also following the practice of the GHGRP and GHGI, emissions of methane entrained in the combustion exhaust of the compressor driver (commonly known as *combustion slip*) *are not* included in compressor emission factors. Combustion slip is tracked as separate methane source line(s) in the GHGI, and included in separate reporting fields for GHGRP and national model.

Vented emissions: Vented emissions include gas released from blowdowns or engine starters, and gas escaping through rod packing seals or centrifugal compressor seals. Blowdowns are typically associated with compressors and yard piping, but may also occur on most other major equipment groups. Gas engine starters utilize gas pressure to crank compressor drivers during start up, and apply only to compressors. As in the GHGI, blowdowns and starting gas emissions are represented by a separate category (“blowdown stacks”) and *are not* included in the major equipment emission factors. Emissions from rod packing and compressor seals *are* including in the compressor emission factor.

Compressors and compressor drivers: All fugitive and vented emissions from the compressor skid are included in the *compressor* emission factor. This includes fugitive emissions on the compressor, compressor driver, and any auxiliary equipment attached to the skid.

While this study updates combustion slip and rod packing estimates, it does not update blowdown or engine starter emission factors, which were not measured, or centrifugal compressor seal emissions, which were encountered in too low a frequency to be statistically valid.

Dehydrator and AGRU vents: Some methane may be present in dehydrator still vents and combustion stacks for heaters on AGRUs. This study develops no new emission factors for

these sources. Dehydrator vents are included in station and national emission estimates using GHGRP estimation methods; AGRU emissions are not estimated by GHGRP and not included.

Flares: Few flares were encountered during the field campaign and no fugitive emissions (leaks) were measured on gas supply lines for these units. No new emission factors are provided by this study. Methane released in combustion exhaust of the flare is estimated for national emissions using GHGRP methods.

S3-4.2 Large Emitters

Major equipment emission factors include estimates of all emissions on every unit that was measured. The majority of emission locations are handled as described in Section S3-3. The handling of the remaining measurement classification, “Exceeded Capacity”, is described here.

For measurement attempts that exceeded the capacity of the available measurement methods, there are no direct measurements of emissions. In most cases, the field team estimated that emissions would exceed the capacity of available instruments *or* observed emissions were too large to safely attempt a measurement. In the data tables, this type of emitter is marked as “Exceeded Capacity”, and is referred to in the text as a *large emitter*.

Table S3-36 provides the number of large emitter sources by station divided into compressors, tanks and all other equipment. Two stations had two large emitters; the remainder had one. Table S3-37 shows the same data, divided by component type. Common vents at the station yard piping, compressors, and tank batteries are the most frequent locations for EC sources.

While large emitters occurred on several component categories, these events are so rare that it does not make sense to include an estimate of emissions in any one component category where a similar (rare) event may occur – but was not observed – in another, similar, category. For example, as per Table S3-37, including large emitter emissions in Compressor/Flanged Connector, but not in Compressor/Threaded Connector would indicate the former emits far larger emissions than the latter, which is unlikely true in general. Similarly a large emitter was encountered on Non-Compressor/Threaded Connector, but not on Non-Compressor/Flanged Connector. Therefore, emissions estimates for large emitters are not included in component average emission factors, but are estimated in the major equipment emission factors, and since major equipment emission factors are the basis of station and national emission estimates, this treatment carries through to those estimates as well.

Table S3-36: Facilities with Exceeded Capacity Measurements

Study ID	Number of Sources			Total
	Compressor	Other Station	Tank	
7	0	0	1	1
11	1	0	1	2
19	0	1	0	1
570	1	0	0	1
1404	0	1	0	1
1564	1	0	0	1
1644	0	0	1	1
1731	0	0	1	1
2686	1	0	0	1
2736	0	0	1	1
2856	0	0	1	1
3001	1	1	0	2
Total	5	3	6	14

Table S3-37: Components with Exceeded Capacity Measurements

Component	Number of Sources						Total	
	Compressor EC Count	Meas. Count	Non-Compressor EC Count	Meas. Count	Tank EC Count	Meas. Count	EC Count	Meas. Count
Common Multi-Unit Vent	2	23			3	22	5	45
Common Single-Unit Vent	1	49			2	79	3	128
Common Station Vent			2	20			2	20
Connector Flanged	1	48					1	81
Connector Threaded			1	87			1	214
Rod Packing Vent	1	530					1	530
Thief Hatch					1	120	1	120
Total	5	777	3	140	6	221	14	1138

For this study, no method was available to measure emissions when they exceeded the capacity of the high flow instrument and a bag would not work for either safety or mechanical reasons. It is therefore necessary to approximate these emissions utilizing data from other studies. Two recent studies performed on compressor stations provide some insight into emission rates; the frequency at which large emitters occur is taken directly from observations during the field campaign.

The first study performed component level measurements on transmission and storage (T&S) stations, paired with downwind tracer flux measurements, and accumulated additional measurements made by partners utilizing similar equipment and methods [16]. Component measurements for this study included measurements made at higher emission rates than was measurable during the current study. We utilize large measurements from the T&S study to provide information about large emitters sizes for this study, but *do not* use the super-emitter category identified in

that study. To convert from kg/h methane to whole gas, we utilize the assumed methane content of 0.95 by mass; a typical assumption for transmission systems.

The second study performed both component level and downwind measurements on gathering compressor stations in the Fayetteville shale play [17]. Since the study utilized similar measurement equipment as this study, component measurements were not made above the range of the high flow instrument. However, the study isolated two large emitters on tanks using downwind methods which were too large to measure with onsite instruments - 606 [± 278] and 140 [± 64.2] kg/h methane. The larger of these measurements was confirmed by three aircraft measurements that estimated similar emission rates. To convert from kg/h methane to whole gas, we utilize an estimated methane content of 0.97 by mass.

These measurements were utilized to estimate emission rates for large emitters that could not be measured in the field campaign:

Rod Packing: The T&S study included 9 rod packing vent measurements that exceeded the high flow device capacity (data file sheet *D14 Rodpacking from T&S*). For use these measurements are fit to a lognormal distribution, shown in Figure S3-14, as an example of the fitting method utilized here.

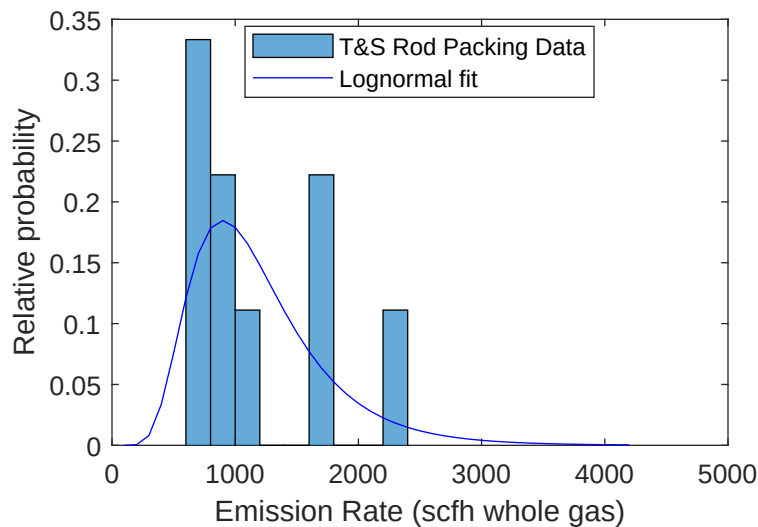


Figure S3-14: Data for rod packing emissions from the T&S study that exceeded the high flow capacity, and resulting lognormal fit to the data.

Common Single-Unit Vents and Thief Hatch: Following a similar method, 15 measurements from isolation valves from the T&S study were utilized to model all single-unit vents and thief hatch emitters (data file sheet *D15 Vents from T&S*).

Common Multi-Unit Vents and Common Station Vent: For these vents we assume emissions will range across both the T&S isolation valve data as well as the additional measurements made during the Fayetteville study. These measurements were concatenated into a single measurement set and fit to a lognormal distribution, with twice the weight given to the Fayetteville measurements to balance the influence of data from both sources.

Connectors: Large emissions from connectors are, by their nature, smaller than the other large emitters described above. These leaks were modeled using a triangular distribution centered on the BHFS upper measurement limit (600scfh whole gas) with an offset of $\pm 20\%$. This method provides an estimate in line with observations, a mean at the maximum reading of the BHFS, and bounded tails.

Resulting emission factors are summarized in Table S3-38.

Table S3-38: Summary of Emission Factors for Large Emitters

Component	Source Data		Lognormal Model		
	Count	Mean & Confidence Interval (scfh whole gas)	μ Parameter	σ Parameter	Mean & Confidence Interval (scfh whole gas)
Rod Packing	9	1,188 [656 to 2,298]	6.99	0.438	1195 [461 to 2561]
Common Single-Unit Vent Thief Hatch	15	2,483 [724 to 9,439]	7.42	0.856	2416 [313 to 8970]
Common Multi-Unit Vent Common Station Vent	19	5,210 [724 to 32,539]	7.83	1.17	4965 [255 to 24750]

The large emitter model impacts the three major equipment emission factors where large emitters occur (see Table S3-37). As has been found in other studies, large emitters occur infrequently, but account for a large fraction of total emissions. The impact is shown in Table S3-39.

Table S3-39: Impact of Large Emitter Model on Emission Factors

Major Equipment Type	Fraction of Samples Larger than Maximum of Reference Model ¹	Fraction of Samples Larger Than CI of Reference Model ²	Emissions Increase Due to Large Emitter Model ³
Compressors	0.0033%	4.5%	70%
Tanks	0.46%	3.3%	74%
Yard Piping	0.95%	3.8%	83%

¹ Fraction of the time emission estimates exceed the largest emission estimate from the reference distribution that does not contain the large emitter model.

² Fraction of the time emission estimates exceed the upper 95% confidence interval of the reference distribution that does not contain the large emitter model..

³ Increase in mean emissions due to the large emitter model.

S3-4.3 Major Equipment Results

Table S3-40 compares study emission factors for major equipment to similar emission factors from the GHGI and GHGRP. Since confidence intervals are not available for some emission factors, the ratio of mean values is utilized for all comparisons.

Table S3-40: Major Equipment Factor Comparison

Component ¹	Emission Factor (scfh whole gas)	GHGI ² Emission Factor	Ratio Study to GHGI	GHGRP East ³ Emission Factor	Mean Ratio Study to GHGRP East	GHGRP West ³ Emission Factor	Mean Ratio Study to GHGRP West
AGRU	4.04 [+451%/-95%]						
Compressor	110 [+542%/-100%]	14.5	7.58	0.5	220	12.7	8.63
Dehydrator	3.41 [+894%/-94%]	3.41	1	1.11	3.07	4.87	0.7
Separator	0.647 [+1188%/-68%]	2.84	0.228	0.05	12.9	6.49	0.0998
Tank	39.3 [+560%/-99%]						
YardPiping	86.3 [+190%/-100%]	1.5	57.5	0.46	188	2.78	31

¹ Abbreviations: “Comp” = Compressor; “AGRU” = Acid gas removal unit;

² [14, Table 3.6-2]

³ [?]

Emission factors are summarized below in Table S3-41 for whole gas and Table S3-42 for methane. Column headers are:

Column Header	Description
Category	name of the emission factor.
Activity Basis and Mean Population	the unit definition (“activity basis”) and number of units screened (“mean population”) used to develop the emission factor. Only units where all detected emissions could be estimated are included in the population.
Emission Factor	emission factor (mean of per-unit emissions), and upper and lower 95% confidence intervals. Since emission factors are developed utilizing Monte Carlo methods, these values are equivalent to a bootstrap mean and confidence interval of the emission factor.
Identified Emission Sources per Unit	mean number of emission sources identified, on a per-unit basis, the fraction of major equipment units in each category with <i>no</i> emissions detected, and the maximum number of emission sources found on one unit.

Appendix C Major Factors provides overview plots of each emission factor. Since many major equipment units were screened with OGI and no leaks were found, units with no detected fugitive emissions are plotted on the logarithmic plots at a low, non-zero value, to make counts of these units visible.

Table S3-41: Major Equipment Whole Gas Emission Factors

Category	Activity Basis	Mean Population	Emission Factor (scfh whole gas)	Confidence Interval (scfh whole gas)	Mean Sources per Unit	Fraction of Units with No Sources	Maximum Sources per Unit
AGRU ¹	Unit	8	4.04	[+264%/-99%]	0.5	63%	2
Compressor	Unit	435	110	[+78%/-44%]	2.69	20%	18
Dehydrator	Unit	124	3.41	[+76%/-59%]	0.532	74%	6
Separator	Unit	326	0.647	[+78%/-53%]	0.153	90%	6
Tank	Tank	251	39.3	[+130%/-62%]	0.793	44%	4
YardPiping	Station	157	86.3	[+265%/-80%]	1.9	48%	17

¹ Emission factor is based upon few measurements and is unlikely to be robust.

Table S3-42: Major Equipment Methane Emission Factors

Category	Activity Basis	Mean Population	Emission Factor (scfh CH ₄)	Confidence Interval (scfh CH ₄)	Mean Sources per Unit	Fraction of Units with No Sources	Maximum Sources per Unit
AGRU ¹	Unit	8	3.61	[+274%/-99%]	0.5	63%	2
Compressor	Unit	435	94.4	[+77%/-46%]	2.69	20%	18
Dehydrator	Unit	124	2.95	[+77%/-59%]	0.532	74%	6
Separator	Unit	326	0.545	[+79%/-54%]	0.153	90%	6
Tank	Tank	251	33.6	[+120%/-61%]	0.793	44%	4
YardPiping	Station	157	74.4	[+238%/-80%]	1.9	48%	17

¹ Emission factor is based upon few measurements and is unlikely to be robust.

S3-5 Station Emission Estimates

Estimates of complete station emissions were assembled for the 180 stations in the field campaign (including the four stations from the GSI longitudinal study, see Section S3-1). Handling of each type of emissions is briefly discussed below.

Vented and Fugitive Emissions: For each unit of major equipment emissions, a unit may be screened and measured, or not measured. For units that were screened and measured, actual measurements are utilized and bootstrapped for uncertainty using the same method as in Section S3-4. If a major equipment unit was not measured, emissions are drawn from the appropriate major equipment emission factor for that unit. Following simulation, emissions are accumulated by major equipment group (compressors, tanks, yard piping, etc.).

Pneumatic Controllers: Counts of PCs were taken from major equipment unit data if the unit was counted. For units where components were not counted, values were drawn from the activity factor for “PCs per unit” (see data tables, sheet *D12 Components Per Unit*) for the appropriate unit type (compressors, tanks, dehydrators, etc.). During the field campaign, the number of pneumatic controllers was counted, but the type of controller (i.e. bleed type) was not determined and recorded. To calculate pneumatic emissions, the mix of high/low/intermittent bleed pneumatic controllers was taken from reports to the GHGRP:

1. If the partner indicated that the station was on instrument air, the pneumatic controller count was assumed to be zero *for the purposes of calculating emissions*. This assumes that all controllers on the station are connected to instrument air.
2. If a station was in a basin where the partner reported to the GHGRP, the pneumatic controller mix was taken from the partner's GHGRP reports for the basin. This assumes that the ratio of controllers is the same for every station in the basin.
3. When a station *was not* in a basin where the partner reported to the GHGRP, the pneumatic controller mix was taken from the mean of all GHGRP reports in that basin.

Results of this analysis are provided in data table *D13 Pneumatic Controller Mix*.

Emissions were estimated utilizing whole gas emission factors from the GHGI for low (1.39 scfh), high (37.3 scfh), and intermittent bleed (13.5 scfh) devices. Uncertainty was assumed to be 20% at a 95% confidence level.

Compressor Exhaust: Methane entrained in compressor exhaust, often known as “combustion slip” or “methane slip”, was developed in Vaughn et al. [2] for all stations in the field study.

Large Emitters: For stations with large emitters, these sources were modeled as in the major equipment emission factor description (Section S3-4). Where equipment was not measured, major equipment emission factors were utilized, including the (low probability) impact of large emitters.

Dehydrator Vent Emissions: Methane released from dehydrator vents was estimated using emissions reported to the GHGRP, divided into “small” dehydrators with throughput <0.4 MMscfd, and “large” dehydrators with throughput >0.4 MMscfd.

For large dehydrators, each unit is reported separately to the GHGRP. For small dehydrators, all units combined into a single estimate for each GHGRP report. Total emission rate in both case was estimated by summing vented methane and methane emitted from flared emissions. Resulting distributions are summarized in table S3-43. The data pulled from GHGRP tables are included in data tables *D2 GHGRP Large Dehy* and *D3 GHGRP Small Dehy*.

If throughput was known for the station, per-dehydrator throughput was estimated by dividing station throughput by the number of dehydrators. If throughput was not known, the distribution for large dehydrators was utilized. Using the large/small selection, the emissions were drawn from the appropriate distribution. Due to the size of stations with dehydrators in the field campaign, only 1 station utilized the small dehydrator distribution to compute emissions.

Table S3-43: Summary of GHGRP Data for Dehydrators

Dehydrator Size (rated throughput)	Records in GHGRP	Emission Rate ($kg \cdot h^{-1}$)	Emission Rate Units
Large (>0.4 MMscfd) ¹	2921	1.88 [0 to 17.2]	$kg \cdot h^{-1} unit^{-1} CH_4$
Small (< 0.4 MMscfd) ²	104	0.188 [0 to 0.331]	$kg \cdot h^{-1} report^{-1} CH_4$

¹ GHGRP Subpart W, reporting year 2017, Table W_DEHYDRATORS_LARGE [19, Table E.3].

² GHGRP Subpart W, reporting year 2017, Table W_DEHYDRATORS_SMALL [19, Table E.1].

Flare Emissions: During the field campaign, field teams noted when flares were connected to tanks to combust vented emissions. These flares may also have been used for other waste gas at the station. No measurements were made of flare emissions. To estimate emissions at stations, we utilize data from GHGRP reports [19, Table N.1], and included in the data tables in sheet *D5 GHGRP Flare Stacks*. For reporting year 2017, the table contains 4318 flares for gathering and boosting, of which 23% are reported as having zero emissions. For the field campaign 10 of 180 stations had flares. To estimate flare emissions, the following process was used:

- If no flares were noted on any tank during the field campaign, we assume there is no flare at the station, and flaring emissions are zero. If a flare is noted on *any* tank, then we assume there is one flare on the station.
- If the partner reported flares to the GHGRP gathering and boosting sector (In Table N.1, field `INDUSTRY_SEGMENT` is equal to “*Onshore petroleum and natural gas gathering and boosting [98.230(a)(9)]*”) emissions from these flares were randomly sampled to estimate flaring emissions.
- If the partner did not report flares to GHGRP as noted above (even through a flare was observed during the field campaign), emissions were estimated from all flares reported in the basin.

It should be noted that GHGRP reports contain a small number of flares with large emissions, which occurred in basins and/or company combinations that were not sampled in the campaign, and thus not used in the analysis process indicated above. The largest 1% of flares have emissions greater than $4.9 kg \cdot h^{-1}$ methane, and account for 37% of total emissions reported to the GHGRP. Therefore, emissions from these larger flares appear in the national model, but are not applicable to the stations measured in this study.

Throughput Normalized Emissions: Throughput was not available for all stations. Where available, throughput normalized emissions were computed by:

1. Converting throughput from the provided units to mass units ($kg \cdot h^{-1}$) using the gas composition from the station, or, if none was available, an average gas composition for all stations.
2. Dividing estimated emissions by throughput.

S3-5.1 Station Results

Selected elements of the station emission estimates are summarized in Table S3-44 with stations listed in order of increasing emissions. Detailed results are provided in the data files *D23 Station Emissions*.

Table S3-44: Station Emissions

Facility ID	Facility Type ¹	Large Emitter Count	Number Comp.	Number Elec. Comp. ²	Instr. Air ³	Emissions ($kg \cdot h^{-1}CH_4$)	Thruput ($kg \cdot h^{-1}CH_4$)	Thruput Normalized Emissions
2364	C	0	1	1	NR	0.00386 [+79%/-79%]	19.6	0.02%
165	C	0	1	1	NR	0.00582 [+65%/-66%]	91.3	0.0064%
2586	C	0	1	1	NR	0.00585 [+65%/-65%]	84.7	0.0069%
2285	C	0	1	1	NR	0.00587 [+64%/-65%]	22.8	0.026%
83	C	0	1	1	NR	0.00588 [+64%/-65%]	81.5	0.0072%
1437	C	0	1	1	NR	0.00592 [+62%/-63%]	97.8	0.0061%
2407	C	0	1	1	NR	0.00772 [+57%/-56%]	84.7	0.0091%
2420	C	0	1	1	NR	0.00787 [+54%/-57%]	61.9	0.013%
2956	C	0	1	1	NR	0.00791 [+56%/-55%]	554	0.0014%
1487	C	0	1	0	No	0.00981 [+50%/-50%]	0	
202	C	0	1	1	NR	0.0117 [+46%/-45%]	313	0.0037%
119	C	0	1	0	NR	0.0328 [+611%/-85%]	31.3	0.1%
85	C	0	1	0	NR	0.0367 [+500%/-78%]	30	0.12%
1510	C	0	1	0	NR	0.0476 [+264%/-86%]	116	0.041%
1442	C	0	1	0	NR	0.0525 [+573%/-81%]		
2685	C	0	1	1	Yes	0.114 [+21%/-18%]		
39	C	0	2	0	NR	0.115 [+288%/-69%]		
1161	C	0	1	1	NR	0.161 [+43%/-38%]		
14	C	0	1	0	No	0.251 [+77%/-33%]		
1643	C	0	1	0	No	0.321 [+90%/-20%]	79.2	0.41%
244	C	0	1	0	NR	0.404 [+548%/-97%]	65.8	0.61%
1846	C	0	1	1	NR	0.405 [+384%/-97%]	228	0.18%
1834	C	0	2	0	Yes	0.573 [+242%/-47%]	843	0.068%
1080	C/T	0	3	0	Yes	1.01 [+313%/-46%]	4.67×10^3	0.022%
2485	C	0	1	0	Yes	1.05 [+12%/-11%]	0	
2607	C	0	1	0	No	1.07 [+73%/-44%]	634	0.17%
504	C	0	1	0	No	1.48 [+276%/-80%]	1.27×10^3	0.12%
1171	C	0	1	0	No	1.66 [+54%/-39%]	210	0.79%
1306	C	0	1	0	No	1.7 [+176%/-80%]	196	0.87%
1488	C	0	3	0	Yes	1.85 [+179%/-55%]		
1610	C	0	1	0	Yes	2.29 [+123%/-77%]		
719	C	0	1	0	No	2.29 [+46%/-28%]	267	0.86%
1308	C	0	1	0	No	2.29 [+235%/-54%]		
315	C	0	1	0	No	2.34 [+65%/-20%]	44.7×10^3	0.0052%
481	C	0	1	0	No	2.54 [+79%/-61%]	0	
2259	C/D	0	2	0	Yes	2.75 [+549%/-88%]	1.63×10^3	0.17%
1291	C	0	2	0	No	2.76 [+181%/-48%]	1.6×10^3	0.17%
2297	C	0	3	0	No	2.97 [+17%/-17%]	2.59×10^3	0.11%
2742	C	0	2	0	Yes	3.1 [+202%/-72%]	3.57×10^3	0.087%
1120	C/D	0	1	0	Yes	3.12 [+562%/-80%]	2×10^3	0.16%
788	C/D	0	5	0	Yes	3.18 [+476%/-85%]	6.01×10^3	0.053%
2188	C	0	1	0	No	3.19 [+172%/-53%]	1.17×10^3	0.27%
895	C	0	1	0	No	3.19 [+55%/-43%]		
1830	C	0	1	0	No	3.22 [+36%/-24%]	246	1.3%
268	C/D	0	1	0	Yes	3.34 [+456%/-64%]		
1165	C	0	3	0	No	3.39 [+54%/-35%]	7.82×10^3	0.043%

Table S3-44 continued

Facility ID	Facility Type ¹	Large Emitter Count	Number Comp.	Number Elec. Comp. ²	Instr. Air ³	Emissions ($kg \cdot h^{-1}CH_4$)	Thruput ($kg \cdot h^{-1}CH_4$)	Thruput Normalized Emissions
1652	C/D	0	2	0	Yes	3.42 [+456%/-64%]	550	0.62%
1756	C	0	2	0	No	3.5 [+157%/-47%]	1.29×10^3	0.27%
1860	C	0	2	0	No	3.54 [+97%/-45%]	991	0.36%
2474	C	0	1	0	No	3.58 [+245%/-76%]	352	1%
556	C	0	1	0	No	3.62 [+173%/-60%]	2.54×10^3	0.14%
2973	C/D	0	4	0	Yes	3.64 [+403%/-86%]	15.6×10^3	0.023%
2773	C/D	0	2	0	Yes	3.83 [+446%/-71%]	4.98×10^3	0.077%
2927	C/D	0	5	0	Yes	3.86 [+392%/-76%]	5.98×10^3	0.065%
2990	C	0	2	0	No	3.89 [+68%/-52%]	970	0.4%
2057	C/D	0	1	0	Yes	3.98 [+352%/-68%]	1.03×10^3	0.39%
704	C	0	2	0	Yes	3.99 [+456%/-81%]	1.47×10^3	0.27%
2964	C	0	3	0	Yes	4.38 [+220%/-67%]	5.2×10^3	0.084%
1141	C/D	0	2	0	Yes	4.62 [+465%/-85%]	2.25×10^3	0.2%
640	C/D	0	2	0	No	5.02 [+326%/-67%]	857	0.59%
1525	C	0	1	0	No	5.31 [+38%/-23%]	10.7×10^3	0.049%
2552	C/D	0	2	0	Yes	5.33 [+272%/-49%]		
952	C	0	2	0	No	5.34 [+113%/-40%]	5.85×10^3	0.091%
1681	C	0	2	0	No	5.4 [+114%/-37%]	9.97×10^3	0.054%
1779	C/D	0	1	0	No	5.74 [+273%/-50%]	469	1.2%
136	C	0	3	0	No	5.86 [+53%/-40%]	2.21×10^3	0.27%
2516	C	0	2	0	No	5.94 [+99%/-35%]	10.1×10^3	0.059%
2214	C	0	2	0	No	6 [+102%/-35%]	3.21×10^3	0.19%
492	C	0	2	0	Yes	6.02 [+101%/-34%]	5.43×10^3	0.11%
2785	C	0	4	0	Yes	6.06 [+130%/-31%]	2.93×10^3	0.21%
2783	C/D	0	1	0	No	6.53 [+247%/-59%]	549	1.2%
1011	C	0	1	0	No	6.61 [+29%/-20%]	483	1.4%
1536	C	0	1	0	No	6.76 [+456%/-84%]	587	1.2%
7	C	1	3	0	Yes	6.88 [+82%/-72%]	1.3×10^3	0.53%
1592	C/D/T	0	1	0	No	7.25 [+223%/-53%]	1.31×10^3	0.55%
1660	C	0	4	0	Yes	7.29 [+402%/-92%]	3.87×10^3	0.19%
2228	C	0	2	0	No	7.49 [+383%/-75%]	596	1.3%
216	C	0	2	0	No	7.5 [+82%/-30%]	2.41×10^3	0.31%
1633	C/D	0	5	0	Yes	7.57 [+256%/-58%]	6.82×10^3	0.11%
1914	C	0	2	0	No	7.7 [+45%/-36%]	775	0.99%
1644	C/D	1	5	0	Yes	7.73 [+338%/-62%]	3.97×10^3	0.19%
94	C/D	0	1	0	No	7.76 [+190%/-51%]	822	0.94%
1418	C	0	5	0	Yes	7.88 [+250%/-54%]	10.1×10^3	0.078%
2963	C/D	0	2	0	No	8.37 [+169%/-46%]	2.1×10^3	0.4%
621	C/D	0	2	0	Yes	8.6 [+487%/-89%]	4.02×10^3	0.21%
2744	C	0	1	0	Yes	8.75 [+124%/-35%]	738	1.2%
19	C/D	1	2	0	Yes	8.75 [+334%/-66%]	10.7×10^3	0.082%
1661	C	0	1	0	No	8.96 [+61%/-27%]	1.16×10^3	0.77%
1451	C/D	0	1	0	Yes	9.08 [+169%/-48%]	5.47×10^3	0.17%
2376	C	0	4	0	No	9.46 [+25%/-16%]	57.1×10^3	0.017%
2469	C/D	0	1	0	No	9.57 [+156%/-38%]	980	0.98%
1937	C/D/T	0	1	0	No	10.7 [+146%/-58%]		

Table S3-44 continued

Facility ID	Facility Type ¹	Large Emitter Count	Number Comp.	Number Elec. Comp. ²	Instr. Air ³	Emissions ($kg \cdot h^{-1}CH_4$)	Thruput ($kg \cdot h^{-1}CH_4$)	Thruput Normalized Emissions
791	C	0	2	0	No	11.2 [+192%/-52%]	1.47×10^3	0.76%
200	C	0	4	0	No	11.3 [+161%/-58%]	2.41×10^3	0.47%
765	C	0	2	0	No	11.5 [+47%/-33%]	4.61×10^3	0.25%
1235	C/D	0	5	0	Yes	11.7 [+186%/-50%]	15.4×10^3	0.076%
2736	C	1	4	0	Yes	11.8 [+588%/-90%]		
772	C	0	3	0	No	12.2 [+81%/-21%]	11.8×10^3	0.1%
247	C/D	0	3	0	No	13.4 [+112%/-38%]	727	1.8%
1702	C/D	0	3	0	No	13.7 [+170%/-40%]	7.46×10^3	0.18%
1315	C/D	0	4	0	Yes	13.8 [+182%/-51%]	13.5×10^3	0.1%
360	C/D	0	3	0	Yes	14.8 [+217%/-57%]		
40	C/D	0	1	0	No	15 [+111%/-50%]	4.88×10^3	0.31%
2268	C/D	0	5	0	Yes	15 [+169%/-41%]	19×10^3	0.079%
2291	C	0	1	0	No	15.1 [+35%/-24%]	919	1.6%
1167	C	0	6	0	No	15.1 [+380%/-54%]	952	1.6%
2416	C/D	0	3	0	Yes	16.4 [+168%/-66%]	9.27×10^3	0.18%
2603	C/D	0	3	0	Yes	16.6 [+292%/-66%]	19.5×10^3	0.085%
1566	C/D	0	3	0	No	17 [+334%/-58%]	9.76×10^3	0.17%
2307	C/D	0	1	0	Yes	17.3 [+91%/-30%]	644	2.7%
2451	C/D	0	2	0	No	17.4 [+308%/-65%]	3.57×10^3	0.49%
699	C/D	0	5	0	No	17.5 [+100%/-29%]	12.2×10^3	0.14%
2116	C/D	0	3	0	No	17.6 [+127%/-43%]	7.56×10^3	0.23%
1875	C/D	0	1	0	No	17.8 [+252%/-53%]	852	2.1%
3004	C	0	3	0	No	18.3 [+46%/-19%]		
206	C/D	0	5	0	Yes	19.9 [+151%/-63%]	21.1×10^3	0.094%
17	C/D/T	0	2	0	No	20.1 [+121%/-49%]	6.02×10^3	0.33%
235	C/D	0	5	0	Yes	20.2 [+75%/-37%]	24.9×10^3	0.081%
3003	C/D	0	2	0	No	21.9 [+71%/-23%]		
430	C/D	0	2	0	No	22.2 [+203%/-48%]	2.74×10^3	0.81%
2691	C/D	0	1	0	No	23.1 [+77%/-37%]	2.44×10^3	0.95%
2491	C	0	2	0	No	23.5 [+32%/-32%]	6.81×10^3	0.34%
1895	C/D	0	3	0	No	23.8 [+124%/-42%]	17.9×10^3	0.13%
1738	C/D	0	3	0	Yes	24 [+115%/-38%]	7.49×10^3	0.32%
744	C/D	0	3	0	No	24 [+321%/-59%]	6.26×10^3	0.38%
634	C/D	0	2	0	No	24.1 [+132%/-45%]	11×10^3	0.22%
117	C	0	7	0	No	25.2 [+369%/-68%]	5.48×10^3	0.46%
251	C/D	0	2	0	No	25.5 [+374%/-43%]	16×10^3	0.16%
1292	C/D	0	12	0	Yes	25.8 [+126%/-31%]	75.6×10^3	0.034%
1825	C/D	0	4	0	Yes	26.2 [+73%/-33%]	22.8×10^3	0.11%
2149	C/D	0	4	0	No	29.2 [+283%/-55%]	4.91×10^3	0.59%
3002	C/D	0	4	0	No	29.3 [+51%/-19%]		
604	C/D	0	2	0	No	29.6 [+89%/-31%]	7.88×10^3	0.38%
2186	C/D	0	3	0	No	30.2 [+66%/-30%]	10.9×10^3	0.28%
2048	C/D	0	3	0	Yes	30.9 [+315%/-53%]	41.3×10^3	0.075%
509	C	0	1	0	No	32.1 [+97%/-32%]	2.73×10^3	1.2%
512	C/D/T	0	3	0	Yes	32.1 [+150%/-37%]	13.2×10^3	0.24%
252	C/D	0	6	0	Yes	32.3 [+93%/-33%]	33.8×10^3	0.095%

Table S3-44 continued

Facility ID	Facility Type ¹	Large Emitter Count	Number Comp.	Number Elec. Comp. ²	Instr. Air ³	Emissions ($kg \cdot h^{-1} CH_4$)	Thruput ($kg \cdot h^{-1} CH_4$)	Thruput Normalized Emissions
1945	C/D	0	2	0	No	33.9 [+77%/-31%]	3.88×10^3	0.87%
1262	C/D/T	0	4	0	Yes	34.1 [+138%/-46%]	3.16×10^3	1.1%
2610	C/D	0	2	0	No	34.5 [+113%/-36%]	4.96×10^3	0.7%
2833	C/D	0	3	0	No	34.9 [+141%/-39%]	11.2×10^3	0.31%
2494	C/D	0	5	0	Yes	35.2 [+91%/-30%]	202×10^3	0.017%
691	C/D/T	0	4	0	Yes	35.8 [+300%/-58%]	20.5×10^3	0.18%
818	C	0	2	0	No	35.9 [+19%/-20%]	35.3×10^3	0.1%
55	C/D	0	4	0	No	36.7 [+83%/-35%]	11.3×10^3	0.32%
1505	C/D	0	4	0	No	38 [+82%/-30%]		
2827	C/D	0	4	0	No	39.7 [+47%/-22%]	5.06×10^3	0.79%
789	C/D	0	5	0	No	40.1 [+113%/-31%]	18.5×10^3	0.22%
2947	C/D	0	6	0	Yes	40.3 [+88%/-29%]	39.1×10^3	0.1%
2874	C	0	4	0	Yes	41.4 [+37%/-25%]	12.7×10^3	0.33%
2686	C/D	1	5	0	Yes	42 [+121%/-31%]	27.1×10^3	0.16%
1564	C/D	1	7	0	No	42.1 [+215%/-47%]	22.6×10^3	0.19%
1126	C/D	0	5	0	Yes	44.3 [+238%/-56%]	10.9×10^3	0.4%
2551	C/D	0	4	0	Yes	44.7 [+51%/-28%]	27.9×10^3	0.16%
1873	C/D/T	0	4	0	Yes	45.3 [+223%/-46%]	22.5×10^3	0.2%
333	C/D	0	6	0	Yes	47.1 [+36%/-20%]	42.3×10^3	0.11%
2064	C/D	0	2	0	No	49.5 [+112%/-39%]	8.53×10^3	0.58%
570	C/D	1	3	0	No	51.2 [+36%/-18%]	8.71×10^3	0.59%
1731	C/D	1	2	0	No	51.8 [+208%/-70%]	430	12%
790	C/D	0	6	0	No	52.4 [+54%/-23%]	18.4×10^3	0.29%
2856	C/D/T	1	5	0	Yes	52.6 [+150%/-37%]	27.5×10^3	0.19%
2557	C/D	0	5	0	No	53.8 [+61%/-24%]	24.2×10^3	0.22%
2575	C/D/T	0	5	0	No	55.8 [+106%/-28%]	19.2×10^3	0.29%
1618	C/D	0	6	0	No	59.6 [+66%/-26%]	24.6×10^3	0.24%
1496	C/D	0	5	0	No	60.7 [+38%/-20%]	22.5×10^3	0.27%
1461	C/D	0	11	0	Yes	71.9 [+35%/-24%]	58.6×10^3	0.12%
2588	C/D	0	5	0	No	72.6 [+60%/-26%]	18×10^3	0.4%
441	C/D	0	6	0	Yes	74.9 [+44%/-24%]	61.3×10^3	0.12%
660	C/D	0	12	0	No	76.6 [+113%/-25%]	14.4×10^3	0.53%
1785	C/D	0	10	0	Yes	79.8 [+82%/-24%]	57.6×10^3	0.14%
66	C	0	12	0	No	80.4 [+19%/-18%]	73×10^3	0.11%
123	C/D	0	7	0	No	81.6 [+106%/-26%]	30.6×10^3	0.27%
1259	C/D	0	8	0	Yes	85.7 [+118%/-31%]	126×10^3	0.068%
2643	C/D/T	0	9	0	Yes	90 [+66%/-29%]	42.4×10^3	0.21%
705	C/D	0	9	0	No	97.3 [+126%/-33%]		
11	C/D	2	5	0	No	127 [+96%/-36%]	19.6×10^3	0.65%
2073	C/D	0	8	0	No	224 [+38%/-17%]	8.23×10^3	2.7%
1404	C/D	1	2	0	Yes	272 [+214%/-71%]	121×10^3	0.22%
3001	C	2	4	0	No	437 [+162%/-65%]		

¹ Abbreviations: “C” = Compression; “D” = Dehydration; “T” = Treating;² Number of compressors driven by electric drivers³ Indicates if instrument air was used for pneumatically actuated valves. NR = “not recorded”

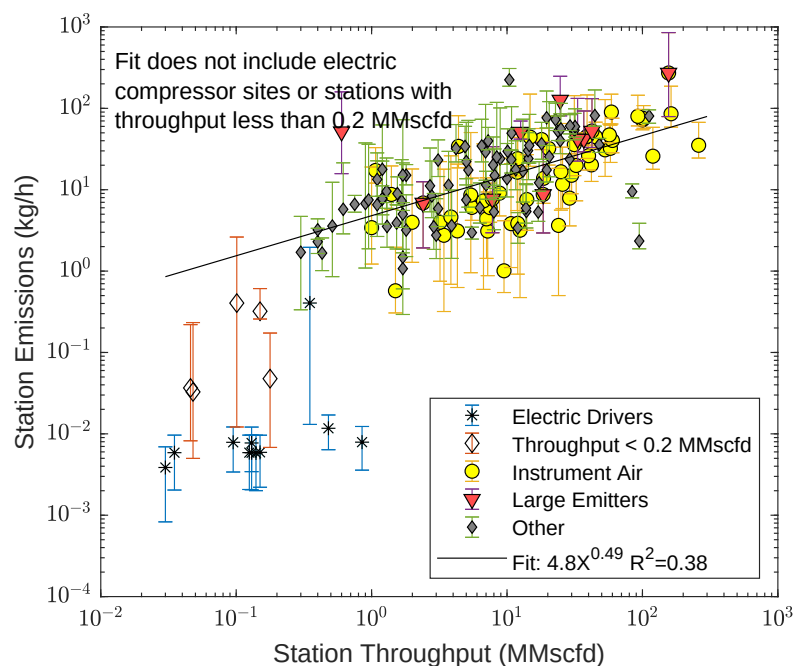


Figure S3-15: Emission rate as a function of throughput for the 157 stations in the field campaign where throughput data was available. Key characteristics of each station are indicated by point shape, including stations with all electric compressor drivers, stations where gas pneumatics and associated actuators are powered by instrument air, and stations with large emitters. Fit does not include 5 stations with throughput below 0.2 MMscfd or 11 small, all-electric, stations.

S3-6 National Emission Estimate

This section describes methods utilized to estimate national emissions. Section S3-6.1 discusses methods utilized to estimate the number of stations, which is used to estimate yard piping emissions, and major equipment units not included in GHGRP reports for the gathering and boosting sector. Section S3-6.2 describes the method utilized to scale activity data from GHGRP reports to a national estimate.

S3-6.1 Estimating Counts not Provided by GHGRP Reports

In general, the national emissions were estimated by utilizing major equipment counts from GHGRP reports for the gathering and boosting segment. However, as shown in Table S3-45, there are two categories where major equipment counts are not available – yard piping and separators. These must be estimated from other data.

Table S3-45: Activity Basis For National Model

Major Equipment Type	Counts in GHGRP Reports	Estimated from Station Count	Estimated from Other Ratio
AGRU	✓		
Compressors	✓ ¹		
Dehydrator	✓ ²		
Separator			✓ ³
Tank	✓ ⁴		
Yard Piping		✓	
Pneumatic Controllers	✓		
Combustion Slip	✓ ⁵		

¹ Count of all compressors, including centrifugal and reciprocating.

² Count of large and small dehydrators combined.

³ Ratio of separators-per-compressor developed from partner data and applied to combined compressor count for each GHGRP report.

⁴ Count of large and small tanks combined.

⁵ Since run hours and engine type are not known, the study assumed that mix seen in partner stations is representative of the mix of compressors in GHGRP.

Station Count Estimate: The number of gathering stations is not included in the GHGRP reports for the gathering and boosting sector. Since the emission factor for yard piping utilizes a *per-station* activity driver, the number of stations must be estimated at the basin or national level. While stations sizes vary widely (from 1 to 16), mean station size is substantially less variable, with 1.8 to 4.4 compressors per station across basins (considering only basins where partner companies had at least 25 stations). Using this data, a distribution of “compressors per station” was developed for each basin where sufficient partner data was available. This ratio is then used to estimate station count from the number of compressors in GHGRP reports.

Partners provided station information associated with 72 GHGRP reports. One partner provided station information by AAPG basin, but reported to the GHGRP using three separate reports, one for each operating company in the basin. In this case, all counts reported in the basin were combined for comparison purposes.

The ratio of compressors-per-station varies widely between basins and GHGRP reports, particularly for basins with few GHGRP reporters, and typically lower gas production. Therefore a separate ratio was developed for each basin where there were at least 100 partner compressors in the basin. To develop these estimates, an inverse Monte Carlo method must be used – identifying the number of stations required to account for reported compressor stations, rather than estimating the number of compressors given a number of stations.

In each basin there are S_p partner stations, each with a defined compressor count, $\{C_k, k = 1..S_p\}$. We also know that N_g compressors were reported to the GHGRP in that basin by partner and non-partner operators. We generate compressor populations by randomly selecting stations from $\{C\}$ and adding the compressor count:

$$\left[\sum_{i=1}^{S_j} \text{draw}(\{C\}, 1) \right] - N_g \leq \max(\{C\}) \quad (4)$$

The unknown in this equation is S_j , the number of stations for Monte Carlo replicate j required to produce N_g reported compressors. The above equation is solved 5000 times to develop a distribution of station counts, $\{N\}$, each of which produces N_g total reported compressors. A distribution of compressors per station, $\{P\}$ is then developed by dividing the reported compressor count by the simulated station count:

$$\{P_j\} = \frac{N_g}{S_j}, j = 1..5000 \quad (5)$$

The resulting ratios are shown in Figure S3-16. For AAPG basins with less than 100 compressors, the station count was estimated utilizing a ratio developed using all partner data in all basins, and labeled as “Default” in the figure. The resulting estimate of station count is shown in Figure S3-20 and provide in data table *D17 Compressors per Station*.

Basin 545 has one GHGRP report with 18 tanks and no reported compressors. For this basin, the station count is estimated using the number of tanks encountered in the field campaign. This results in an estimate of 0.6 [0 to 1] stations per tank.

Separator Count Estimate: Similarly, the ratio of separators-per-compressor was developed to estimate the number of separators for each basin with GHGRP reports. Since a separator count was not included in site information provided by the partners (Section S3-1), this ratio was estimated from data collected on the 180 stations visited during the field campaign. Scaling factors were developed for each basin where the field campaign measured a minimum of 5 stations. In each basin, the count of separators and compressors for each station was bootstrapped, producing a distribution of ratios for each basin. All data not used in the per-basin factors was utilized to create a default distribution for all other basins. Results are shown in Figure S3-17 and in data table *D18 Separators per Compressor*.

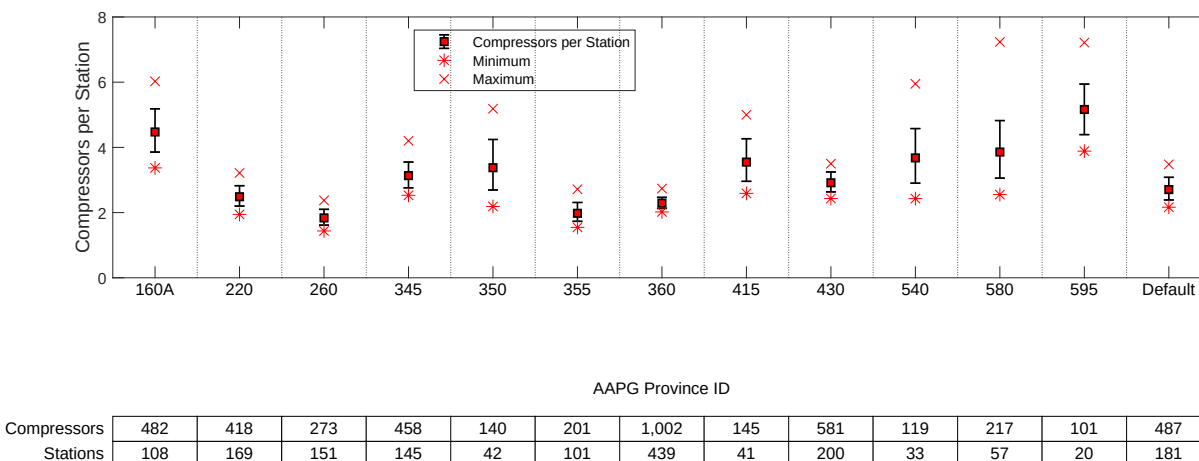


Figure S3-16: The ratio of compressors per station developed from partner data to estimate the station count for each AAPG basin. For each of the basins listed, partner data included more than 100 stations and a basin-specific ratio was developed. Partner data from outside the listed basins was used to develop a default factor for use in all other basins.

As with the station count for the basin with no reported compressors (basin 545), we estimated the separator count from the count of tanks and separators encountered in the field campaign, i.e. 1.1 [0 to 3] separators per tank.

Methane in Combustion Exhaust: Combustion slip (unburned methane entrained in combustion exhaust) is taken directly from Vaughn et al. [2], where a distribution of estimates was developed for each basin. Briefly, the model estimates the mix of compressor drivers for each basin using a combination of data from the GHGRP and data collected in the field campaign of this study. The model also estimates the typical load on compressors and average run time per year. The mix of driver types overall, and the mix of engine types for engine-driven units, varies substantially between basins. As a result, the combustion slip per compressor unit varies substantially between basins. Data from that paper is repeated in the data table *D19 Combustion Slip By Basin*.

Dehydrator Vent Emissions: Reported emissions for dehydrator vents (still or reboiler vents) were utilized directly from data reported to the GHGRP and then scaled to national estimates as discussed below. Large dehydrators (≥ 0.4 MMscfd throughput) are reported with one record per unit [19, Table E.3]. Small dehydrators (< 0.4 MMscfd throughput) are aggregated and reported as a single record for each basin [19, Table E.1].

Flaring Emissions: Flares are reported individually to the GHGRP [19, Table N.1] by estimating the quantity of gas sent to the flare and the methane combustion efficiency (typically 98%). GHGRP reports were used directly and scaled to national estimates as discussed below.

Blowdowns: Equipment blowdowns are reported as a count of blowdowns in several categories with estimated blowdown volumes [19, Table I.1 and Table I.2]. This data is included in the data tables in sheet *D4 GHGRP Blowdown Stacks*. Emissions from pipelines were excluded from this simulation, since this study focuses on station emissions.

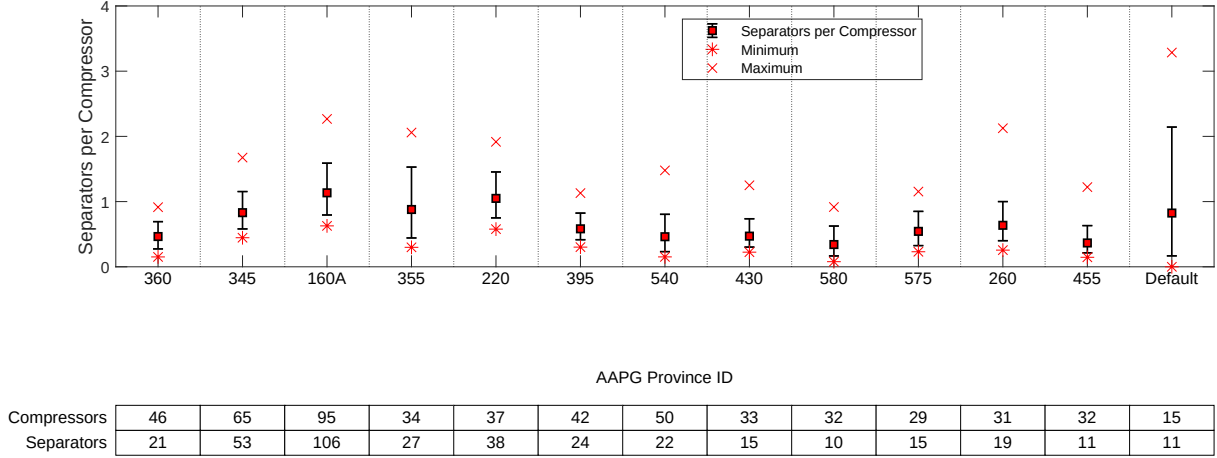


Figure S3-17: The ratio of separators per compressor developed from stations sampled in the field campaign. Basin-specific factors are developed for all basins where at least 5 were sampled in the field campaign. All data not used for basin-specific factors was utilized to develop the default factor for use in other basins.

S3-6.2 Scaling from GHGRP Reports to National Estimate

Gathering and boosting operations are reported to GHGRP if emissions from any operator's operation in a basin exceeds the reporting threshold of 25,000 metric tonnes of CO₂ equivalent emissions. Smaller operators in any basin, and small operations in basins with little gas production do not exceed this threshold and are not reported. Therefore, in addition to stations and equipment represented by the GHGRP reports, there are additional stations and equipment which are not reported to the GHGRP. No external information exists to directly scale GHGRP reports to national estimates. Therefore, to estimate the amount of non-reported equipment, we utilize a surrogate model developed from the production sector.

The DrillingInfo database [20] tracks the total natural gas production in the USA at a detailed level. GHGRP reports for the production sector (subject to the same reporting threshold as G&B) include natural gas production equipment and production rate of oil and gas for all production operations, by basin. The national model assumed that the ratio between reported and non-reported gas production is a good estimate of the ratio between reported and non-reported gathering stations and equipment, and used this ratio to scale up GHGRP reported equipment counts and associated emissions to a national estimate. In general, we utilize the ratio:

$$f_1 = \sum_{i \in \{N\}} g_i / \sum_{i \in \{N\}} d_i \quad (6)$$

where d_i is the gas production from DrillingInfo, and g_i is the gas production reported to the GHGRP production sector, for basin i , and N is the set of all basins with GHGRP reports. Any equipment count, station count, or emission estimate in basin i , can be scaled using this factor to account for operations not reported to the GHGRP by applying $X_i = x_i / f_1$.

Starting with reporting year 2017 GHGRP data[19], we apply the following filters:

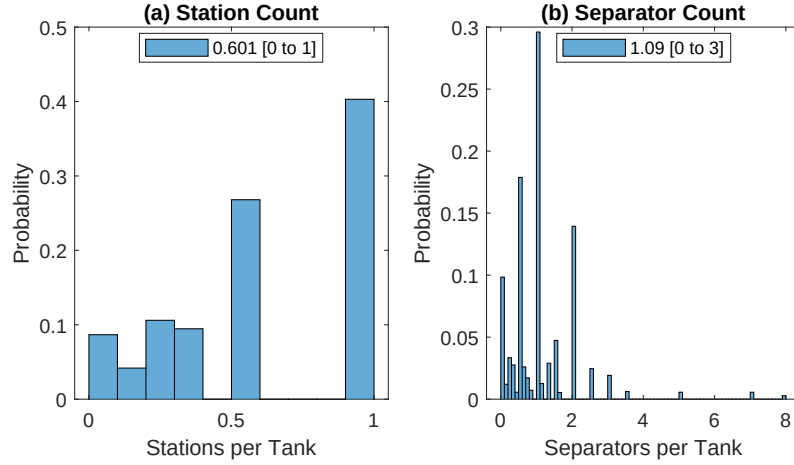


Figure S3-18: For basins with no reported compressors, station and separator count were estimated from reported tank count. Panel (a) shows the distribution of stations per tank, while panel (b) shows the distribution of separators per tank. Distributions are shown with no bootstrapping. Data can be extracted from data table *D9 Equipment*.

- GHGRP basin 210 has a known error where production is more than 250% of the DrillingInfo data, likely due to an erroneous report by one company; data from this basin was not utilized.
- To concentrate our analysis on gas-producing facilities, we eliminate any GHGRP basin where less than 50% of gas produced from wells is sold. This filter removes 6 basins accounting for 0.89% of GHGRP-reported gas production.

Starting with 65 basins that have non-zero DrillingInfo production data, 38 of those basins have GHGRP reports and 32 remain after all filters are applied; i.e. $N = 32$. These 32 basins produce 88% of gas production in the USA (DrillingInfo numbers). For currently available data $f_1 = 90\%$. All data is summarized in data table *D16 Production Ratio*.

In addition, the ratio d_i/g_i varies substantially between basins, particularly for basins with lower gas production and/or few GHGRP reports. Therefore, we modify Eqn. 6 to weight the probability of each basin by the gas production from DrillingInfo in each basin, and use the one ratio (with uncertainty) to scale all basins. This is performed by resampling $\{N\}$ so that each basin is represented proportionally to its gas production, and recomputing f :

$$f_w = \sum_{i \in \{\hat{N}\}} g_i / \sum_{i \in \{\hat{N}\}} d_i \quad (7)$$

where $\hat{N}$ is the proportionally up-sampled set of basins. Eqn. 6 is applicable in any basin with one or more GHGRP reports. For currently available data $f_w = 0.936$ [0.907 to 0.957], meaning that this study estimates that approximately 94% of gathering station infrastructure is reported to the GHGRP. Initial and weighted distributions are shown in S3-19.

In addition, there are 27 basins with no production GHGRP reports but some DrillingInfo production. To account for this production, after scaling all basins by f_w , the total is additionally scaled to account for G&B operations outside basins with GHGRP reports. This factor is:

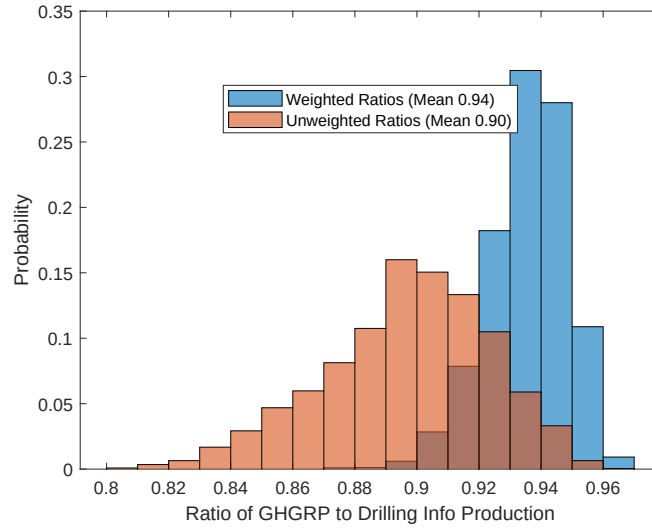


Figure S3-19: Scaling factor developed by comparing DrillingInfo™ with gas production numbers from the GHGRP production [19, Table AA.1.i] at the basin level. Unweighted ratios reflect the input data after filtering (Eqn. 6), while weighted ratios reflect a weighted bootstrap of the input data (Eqn. 7).

$$f_o = \sum_{j \in \{M\}} d_j / \sum_{k \in \{M+N\}} d_k \quad (8)$$

where $\{M\}$ is the set of basins with no GHGRP reports. These basins constitute a small portion of USA gas production and $f_o = 0.63\%$.

Finally, results for station counts or emission estimates in each basin are scaled using f_w and total national emissions are scaled by $(1 + f_o)$ to estimate national emissions:

$$X = (1 + f_o) \sum_{i \in \{N\}} \frac{x_i}{f_w} \quad (9)$$

where x_i is a station count or emission estimate and X is the national estimate of that parameter. In practice both x_i and f_w are distributions and the division $\frac{x_i}{f_w}$ is accomplished using Monte Carlo methods.

Using these ratios and the ratio of compressors-per-station developed in Section S3-6.1, a national station count estimate was developed as shown in Figure S3-20. Initial scaling from GHGRP reports resulted estimate of 5,683 [5,447 to 5,926] stations, and the application of $(1 + f_o)/f_w$ results in a national estimate of 6,111 [5,852 to 6,377] stations, including 6,075 [5,817 to 6,339] stations within basins with GHGRP reports and 36 [34 to 37] in other basins.

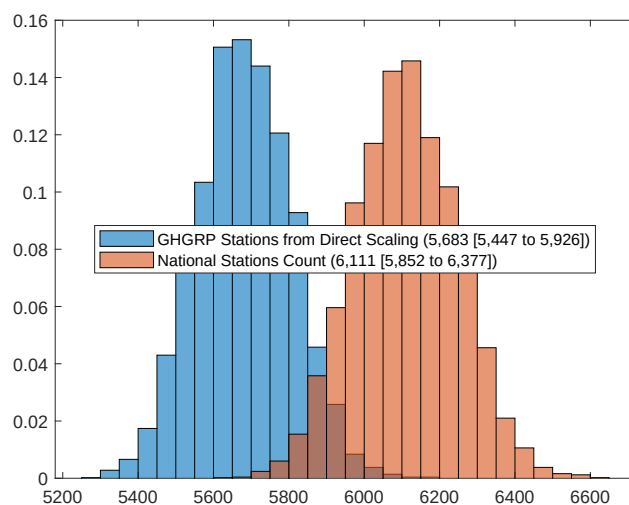


Figure S3-20: Estimated national station count. The initial estimate is made by estimating station count from compressor count, by basin, using ratios in Figure S3-16. The resulting estimate is scaled to a national estimate utilizing the gas production ratio between DrillingInfo and GHGRP production reports.

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