Statement of Basis

Permit to Construct No. P-2015.0051
Project ID 61598

Alta Mesa - ML Investments 1-3
Payette, Idaho

Facility ID 075-00024

Final

October 14, 2016
Kelli Wetzel KW
Permit Writer

The purpose of this Statement of Basis is to satisfy the requirements of IDAPA 58.01.01.et seq, Rules for the Control of Air Pollution in Idaho, for issuing air permits.

ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

AAC	acceptable ambient concentrations
AACC	acceptable ambient concentrations for carcinogens
acfm	actual cubic feet per minute
ASTM	American Society for Testing and Materials
Btu	British thermal units
CAA	Clean Air Act
CEMS	continuous emission monitoring systems
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CI	compression ignition
CMS	continuous monitoring systems
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	CO_2 equivalent emissions
DEQ	Department of Environmental Quality
dscf	dry standard cubic feet
EL	screening emission levels
EPA	U.S. Environmental Protection Agency
GHG	greenhouse gases
gr	grains (1 lb = 7,000 grains)
HAP	hazardous air pollutants
hp	horsepower
hr/yr	hours per consecutive 12 calendar month period
ICE	internal combustion engines
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
km	kilometers
lb/hr	pounds per hour
m	meters
MACT	Maximum Achievable Control Technology
MMBtu	million British thermal units
MMscf	million standard cubic feet
NAAQS	National Ambient Air Quality Standard
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NSPS	New Source Performance Standards
O&M	operation and maintenance
O_2	oxygen
PAH	polyaromatic hydrocarbons
PC	permit condition
PM	particulate matter
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
POM	polycyclic organic matter
ppm	parts per million
ppmw	parts per million by weight
PSD	Prevention of Significant Deterioration
psig	pounds per square inch gauge
PTC	permit to construct
PTC/T2	permit to construct and Tier II operating permit

PTE	potential to emit
RICE	reciprocating internal combustion engines
Rules	*Rules for the Control of Air Pollution in Idaho*
scf	standard cubic feet
SCL	significant contribution limits
SIP	State Implementation Plan
SM	synthetic minor
SM80	synthetic minor facility with emissions greater than or equal to 80% of a major source threshold
SO_2	sulfur dioxide
SO_x	sulfur oxides
T/day	tons per calendar day
T/hr	tons per hour
T/yr	tons per consecutive 12 calendar month period
T2	Tier II operating permit
TAP	toxic air pollutants
U.S.C.	United States Code
VOC	volatile organic compounds
yd^3	cubic yards
$\mu g/m^3$	micrograms per cubic meter

FACILITY INFORMATION

Description

Alta Mesa Services, LP (Alta Mesa) submitted an application for a new oil and gas well site gathering and processing facility to be called ML Investments 1-3 located at 44°3'46.65" N; 116°48'16.53" W approximately 5 miles northeast of the city of Payette. The proposed facility is necessary for the gathering and processing of produced hydrocarbons.

Production from this site will flow through separators and line heaters where any free water and natural gas liquids will be collected. Liquids separated from the separators will be sent to onsite tanks for storage where they will be pumped to trucks for disposal. The gas will proceed to a central dehydration unit where the remaining water will be removed from the wet gas stream. The gas will then be compressed with a natural gas engine compressor to be sent to pipeline and moved to the refrigeration plant approximately eight miles to the south.

Permitting History

This is the initial PTC for a new facility thus there is no permitting history.

Application Scope

This permit is the initial PTC for this facility.

The applicant has proposed to install and operate an oil and gas well site gathering and processing facility.

Application Chronology

September 28, 2015	DEQ received an application and an application fee.
October 14 – October 29, 2015	DEQ provided an opportunity to request a public comment period on the application and proposed permitting action.
October 28, 2015	DEQ determined that the application was incomplete.
October 28, 2015	DEQ received supplemental information from the applicant.
November 28, 2015	DEQ determined that the application was incomplete.
December 2, 2015	DEQ received supplemental information from the applicant.
December 30, 2015	DEQ determined that the application was incomplete.
February 16, 2016	DEQ received supplemental information from the applicant.
April 22, 2016	DEQ determined that the application was complete.
June 15, 2016	DEQ made available the draft permit and statement of basis for peer and regional office review.
August 12, 2016	DEQ made available the draft permit and statement of basis for applicant review.
August 31 – September 30, 2016	DEQ provided a public comment period on the proposed action.
October 12, 2016	DEQ received the permit processing fee.
October 14, 2016	DEQ issued the final permit and statement of basis.

TECHNICAL ANALYSIS

Emissions Units and Control Equipment

Table 1 EMISSIONS UNIT AND CONTROL EQUIPMENT INFORMATION

Source ID No.	Sources	Control Equipment
Compressor Engine ENG1	Manufacturer: Caterpillar Model: G398 TA Type Manufacture Date: TBD Max. capacity: 610 bhp Fuel: Natural Gas	None
Well Head Heater WHHTR1	Rated capacity: 0.05 MMBtu/hr Fuel: Natural Gas	None
Line Heater LNHTR1	Rated capacity: 0.5 MMBtu/hr Fuel: Natural Gas	None
Heater Treater HTRTR1	Rated capacity: 1.0 MMBtu/hr Fuel: Natural Gas	None
10 Oil Tanks OILTNK1-10	Capacity: 500 bbl each	Control Efficiency 95.0%
4 Water Tanks WTRTNK1-4	Capacity: 80 bbl each	None
Oil Loading LOAD1	Throughput: 500 BOPD	Control Efficiency 98.0%
Flare FLR1	Throughput: 1500 scf/d	None (considered an emission control device during an emergency situation)

Emissions Inventories

Potential to Emit

IDAPA 58.01.01 defines Potential to Emit as the maximum capacity of a facility or stationary source to emit an air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the facility or source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is state or federally enforceable. Secondary emissions do not count in determining the potential to emit of a facility or stationary source.

Using this definition of Potential to Emit an emission inventory was developed for the compressor engine, well head heater, line heater, heater treater, flare, ten oil tanks, four water tanks, and oil loading operations at the facility (see Appendix A) associated with this proposed project. Emissions estimates of criteria pollutant, greenhouse gases (GHG), hazardous air pollutants (HAP), and toxic air pollutants (TAP) were based on emission factors from AP-42, operation of 8,760 hours per year, manufacturer data, and process information specific to the facility for this proposed project. Tank emissions were calculated using U.S. EPA's TANKS program, version 4.09b.

Uncontrolled Potential to Emit

Using the definition of Potential to Emit, uncontrolled Potential to Emit is then defined as the maximum capacity of a facility or stationary source to emit an air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the facility or source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall **not** be treated as part of its design **since** the limitation or the effect it would have on emissions **is not** state or federally enforceable.

The uncontrolled Potential to Emit is used to determine if a facility is a "Synthetic Minor" source of emissions. Synthetic Minor sources are facilities that have an uncontrolled Potential to Emit for regulated air pollutants or HAP above the applicable Major Source threshold without permit limits.

The following table presents the uncontrolled Potential to Emit for regulated air pollutants as submitted by the Applicant and verified by DEQ staff. See Appendix A for a detailed presentation of the calculations and the assumptions used to determine emissions for each emissions unit. For this operation uncontrolled Potential to Emit is based upon a worst-case for operation of the facility of 8,760 hr/yr.

Table 2 UNCONTROLLED POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Source	$PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC	CO_2e
	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr
Point Sources						
ENG1	0.40	0.01	5.89	11.77	2.94	2213.2
WHHTR1	0.001	0.0001	0.02	0.02	0.001	23.2
LNHTR1	0.01	0.001	0.18	0.15	0.01	232.5
HTRTR1	0.03	0.002	0.36	0.30	0.02	464.9
OILTNK1-10	0.00	0.00	0.00	0.00	38.4	0.00
WTRTNK1-4					0.63	
LOAD1					23.9	
FLR1	0.02	0.02	1.55	7.06	1.85	4802.5
Total, Point Sources	**0.46**	**0.03**	**8.00**	**19.30**	**67.8**	**7736.3**

The following table presents the uncontrolled Potential to Emit for HAP pollutants as submitted by the Applicant and verified by DEQ staff. See Appendix A for a detailed presentation of the calculations and the assumptions used to determine emissions for each emissions unit. For this operation uncontrolled Potential to Emit is based upon a worst-case for operation of the facility of 8,760 hr/yr. Then, the worst-case maximum HAP Potential to Emit was determined for this operation.

Table 3 UNCONTROLLED POTENTIAL TO EMIT FOR HAZARDOUS AIR POLLUTANTS

Hazardous Air Pollutants	PTE (T/yr)
Benzene	0.29
Ethylbenzene	0.07
Formaldehyde	1.10
n-Hexane	0.07
Toluene	0.30
2,2,4-Trimethylpentane	0.01
Xylene	0.24
Total	**2.08**

Pre-Project Potential to Emit

This is a new facility. Therefore, pre-project emissions are set to zero for all criteria pollutants.

Post Project Potential to Emit

Post project Potential to Emit is used to establish the change in emissions at a facility and to determine the facility's classification as a result of this project. Post project Potential to Emit includes all permit limits resulting from this project.

The following table presents the post project Potential to Emit for criteria and GHG pollutants from all emissions units at the facility as determined by DEQ staff. See Appendix A for a detailed presentation of the calculations of these emissions for each emissions unit.

Table 4 POST PROJECT POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Source	$PM_{10}/PM_{2.5}$		SO_2		NO_X		CO		VOC		CO_2e	
	lb/hr(a)	T/yr(b)	lb/hr(a)	T/yr(b)	lb/hr(a)	T/yr(b)	lb/hr(a)	T/yr(b)	lb/hr(a)	T/yr(b)	lb/hr(a)	T/yr(b)
ENG1	0.09	0.40	0.003	0.01	1.34	5.89	2.69	11.77	0.67	2.94	505.3	2213.2
WHHTR1	0.0003	0.001	0.00002	0.0001	0.004	0.02	0.003	0.02	0.0002	0.001	5.3	23.2
LNHTR1	0.003	0.01	0.0002	0.001	0.04	0.18	0.03	0.15	0.002	0.01	53.1	232.5
HTRTR1	0.006	0.03	0.0005	0.002	0.08	0.36	0.07	0.30	0.005	0.02	106.1	464.9
OILTNK1-10									4.38	19.20		
WTRTNK1-4									0.14	0.63		
LOAD1									0.60	0.48		
FLR1	0.005	0.02	0.005	0.02	0.35	1.55	1.61	7.06	0.42	1.85	1096.5	4802.5
Post Project Totals	**0.10**	**0.46**	**0.009**	**0.03**	**1.81**	**8.00**	**4.40**	**19.30**	**6.22**	**25.13**	**1766.3**	**7736.3**

a) Controlled average emission rate in pounds per hour is a daily average, based on the proposed daily operating schedule and daily limits.
b) Controlled average emission rate in tons per year is an annual average, based on the proposed annual operating schedule and annual limits.

Change in Potential to Emit

The change in facility-wide potential to emit is used to determine if a public comment period may be required and to determine the processing fee per IDAPA 58.01.01.225. The following table presents the facility-wide change in the potential to emit for criteria pollutants.

Table 5 CHANGES IN POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Source	$PM_{10}/PM_{2.5}$		SO_2		NO_X		CO		VOC		CO_2e	
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
Pre-Project Potential to Emit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Post Project Potential to Emit	**0.10**	**0.46**	**0.009**	**0.03**	**1.81**	**8.00**	**4.40**	**19.30**	**6.22**	**25.13**	**1766.3**	**7736.3**
Changes in Potential to Emit	**0.10**	**0.46**	**0.009**	**0.03**	**1.81**	**8.00**	**4.40**	**19.30**	**6.22**	**25.13**	**1766.3**	**7736.3**

Non-Carcinogenic TAP Emissions

A summary of the estimated PTE for emissions increase of non-carcinogenic toxic air pollutants (TAP) is provided in the following table.

Pre- and post-project, as well as the change in, non-carcinogenic TAP emissions are presented in the following table:

Table 6 PRE- AND POST PROJECT POTENTIAL TO EMIT FOR NON-CARCINOGENIC TOXIC AIR POLLUTANTS

Non-Carcinogenic Toxic Air Pollutants	Pre-Project 24-hour Average Emissions Rates for Units at the Facility (lb/hr)	Post Project 24-hour Average Emissions Rates for Units at the Facility (lb/hr)	Change in 24-hour Average Emissions Rates for Units at the Facility (lb/hr)	Non-Carcinogenic Screening Emission Level (lb/hr)	Exceeds Screening Level? (Y/N)
Acrolein	0.00E-03	2.45E-02	2.45E-02	0.017	No
Biphenyl	0.00E-03	1.0E-03	1.0E-03	0.1	No
Chlorobenzene	0.00E-03	1.0E-04	1.0E-04	23	No
Chloroethane	0.00E-03	1.0E-05	1.0E-05	176	No
Cyclohexane	0.00E-03	3.0E-06	3.0E-06	70	No
Cyclopentane	0.00E-03	1.1E-03	1.1E-03	114.667	No
1,2-Dichloropropane	0.00E-03	1.0E-04	1.0E-04	23.133	No
Ethylbenzene	0.00E-03	1.3E-03	1.3E-03	29	No
Heptane	0.00E-03	3.32E-02	3.32E-02	109	No
n-Hexane	0.00E-03	2.61E-02	2.61E-02	12	No
Methanol	0.00E-03	1.46E-02	1.46E-02	17.3	No
Methylcyclohexane	0.00E-03	5.9E-03	5.9E-03	107	No
Naphthalene	0.00E-03	5.0E-04	5.0E-04	3.33	No
n-Nonane	0.00E-03	5.0E-04	5.0E-04	70	No
n-Octane	0.00E-03	1.7E-03	1.7E-03	93.3	No
Pentanes	0.00E-03	5.97E-02	5.97E-02	118	No
Phenol	0.00E-03	1.0E-04	1.0E-04	1.27	No
Toluene	0.00E-03	6.7E-03	6.7E-03	25	No
2,2,4-Trimethylpentane	0.00E-03	2.2E-03	2.2E-03	23.3	No
Xylene	0.00E-03	3.8E-03	3.8E-03	29	No

None of the PTEs for non-carcinogenic TAP were exceeded as a result of this project. Therefore, modeling is not required for any non-carcinogenic TAP because none of the 24-hour average carcinogenic screening ELs identified in IDAPA 58.01.01.585 were exceeded.

Carcinogenic TAP Emissions

A summary of the estimated PTE for emissions increase of carcinogenic toxic air pollutants (TAP) is provided in the following table.

Table 7 PRE- AND POST PROJECT POTENTIAL TO EMIT FOR CARCINOGENIC TOXIC AIR POLLUTANTS

Carcinogenic Toxic Air Pollutants	Pre-Project Annual Average Emissions Rates for Units at the Facility (lb/hr)	Post Project Annual Average Emissions Rates for Units at the Facility (lb/hr)	Change in Annual Average Emissions Rates for Units at the Facility (lb/hr)	Carcinogenic Screening Emission Level (lb/hr)	Exceeds Screening Level? (Y/N)
Acetaldehyde	0.00E-03	3.98E-02	3.98E-02	3.00E-03	Yes
Benzene	0.00E-03	1.10E-02	1.10E-02	8.00E-04	Yes
Benzo(e)pyrene	0.00E-03	2.0E-06	2.0E-06	2.00E-06	No
1,3-Butadiene	0.00E-03	3.2E-03	3.2E-03	2.40E-05	Yes
Carbon Tetrachloride	0.00E-03	2.0E-04	2.0E-04	4.40E-04	No
Chloroform	0.00E-03	1.0E-04	1.0E-04	2.80E-04	No
1,1-Dichloroethane	0.00E-03	1.0E-04	1.0E-04	2.50E-04	No
1,2-Dichloroethane	0.00E-03	1.0E-04	1.0E-04	2.50E-04	No
1,3-Dichloropropene	0.00E-03	1.0E-04	1.0E-04	1.90E-07	Yes
Ethylene Dibromide	0.00E-03	2.0E-04	2.0E-04	3.00E-05	Yes
Formaldehyde	0.00E-03	2.51E-01	2.51E-01	5.10E-04	Yes
Methylene Chloride	0.00E-03	2.0E-04	2.0E-04	1.60E-03	No
PAH	0.00E-03	7.0E-04	7.0E-04	9.10E-05	Yes
1,1,2,2-Tetrachloroethane	0.00E-03	2.0E-04	2.0E-04	1.10E-05	Yes
1,1,2-Trichloroethane	0.00E-03	2.0E-04	2.0E-04	4.20E-04	No
Vinyl Chloride	0.00E-03	1.0E-04	1.0E-04	9.40E-04	No

Some of the PTEs for carcinogenic TAP were exceeded as a result of this project but in accordance with IDAPA 58.01.01.210.20, several TAPs are regulated under 40 CFR Part 60 or 40 CFR Part 63 and no further procedures for demonstrating preconstruction compliance is required.

Post Project HAP Emissions

The following table presents the post project potential to emit for HAP pollutants from all emissions units at the facility as submitted by the Applicant and verified by DEQ staff. See Appendix A for a detailed presentation of the calculations of these emissions for each emissions unit.

Table 8 HAZARDOUS AIR POLLUTANTS EMISSIONS POTENTIAL TO EMIT SUMMARY

Hazardous Air Pollutants	PTE (T/yr)
Benzene	0.047
Ethylbenzene	0.005
Formaldehyde	1.101
n-Hexane	0.071
Toluene	0.028
2,2,4-Trimethylpentane	0.008
Xylene	0.017
Totals	**1.28**

The estimated PTE for all federally listed HAPs combined is below 25 T/yr and no PTE for a federally listed HAP exceeds 10 T/yr. Therefore, this facility is not a major source for HAPs.

Ambient Air Quality Impact Analyses

As presented in the Modeling Memo in Appendix B, the estimated emission rate of NO_X and CO from this project exceeded applicable screening emission levels (EL) and published DEQ modeling thresholds established in IDAPA 58.01.01.585-586 and in the State of Idaho Air Quality Modeling Guideline[1]. Refer to the Emissions Inventories section for additional information concerning the emission inventories.

The applicant has demonstrated pre-construction compliance to DEQ's satisfaction that emissions from this facility will not cause or significantly contribute to a violation of any ambient air quality standard. The applicant has also demonstrated pre-construction compliance to DEQ's satisfaction that the emissions increase due to this permitting action will not exceed any acceptable ambient concentration (AAC) or acceptable ambient concentration for carcinogens (AACC) for toxic air pollutants (TAP). A summary of the Ambient Air Impact Analysis for TAP is provided in Appendix A.

An ambient air quality impact analyses document has been crafted by DEQ based on a review of the modeling analysis submitted in the application. That document is part of the final permit package for this permitting action (see Appendix B).

REGULATORY ANALYSIS

Attainment Designation (40 CFR 81.313)

The facility is located in Payette County, which is designated as attainment or unclassifiable for $PM_{2.5}$, PM_{10}, SO_2, NO_2, CO, and Ozone. Refer to 40 CFR 81.313 for additional information.

Facility Classification

The AIRS/AFS facility classification codes are as follows:

For THAPs (Total Hazardous Air Pollutants) Only:

A = Use when any one HAP has actual or potential emissions ≥ 10 T/yr or if the aggregate of all HAPS (Total HAPs) has actual or potential emissions ≥ 25 T/yr.

SM80 = Use if a synthetic minor (potential emissions fall below applicable major source thresholds if and only if the source complies with federally enforceable limitations) and the permit sets limits ≥ 8 T/yr of a single HAP or ≥ 20 T/yr of THAP.

SM = Use if a synthetic minor (potential emissions fall below applicable major source thresholds if and only if the source complies with federally enforceable limitations) and the potential HAP emissions are limited to < 8 T/yr of a single HAP and/or < 20 T/yr of THAP.

B = Use when the potential to emit without permit restrictions is below the 10 and 25 T/yr major source threshold

UNK = Class is unknown

For All Other Pollutants:

A = Actual or potential emissions of a pollutant are ≥ 100 T/yr.

SM80 = Use if a synthetic minor for the applicable pollutant (potential emissions fall below 100 T/yr if and only if the source complies with federally enforceable limitations) and potential emissions of the pollutant are ≥ 80 T/yr.

SM = Use if a synthetic minor for the applicable pollutant (potential emissions fall below 100 T/yr if and only if the source complies with federally enforceable limitations) and potential emissions of the

[1] Criteria pollutant thresholds in Table 2, State of Idaho Guideline for Performing Air Quality Impact Analyses, Doc ID AQ-011, September 2013.

pollutant are < 80 T/yr.

B = Actual and potential emissions are < 100 T/yr without permit restrictions.

UNK = Class is unknown.

Table 9 REGULATED AIR POLLUTANT FACILITY CLASSIFICATION

Pollutant	Uncontrolled PTE (T/yr)	Permitted PTE (T/yr)	Major Source Thresholds (T/yr)	AIRS/AFS Classification
PM	0.46	0.46	**100**	B
$PM_{10}/PM_{2.5}$	0.46	0.46	**100**	B
SO_2	0.03	0.03	**100**	B
NO_X	8.00	8.00	**100**	B
CO	19.30	19.30	**100**	B
VOC	67.8	25.13	**100**	B
HAP (single)	1.10	1.10	**10**	B
HAP (Total)	2.08	1.28	**25**	B

Permit to Construct (IDAPA 58.01.01.201)

IDAPA 58.01.01.201 .... Permit to Construct Required

The permittee has requested that a PTC be issued to the facility for the proposed new emissions source. Therefore, a permit to construct is required to be issued in accordance with IDAPA 58.01.01.220. This permitting action was processed in accordance with the procedures of IDAPA 58.01.01.200-228.

Tier II Operating Permit (IDAPA 58.01.01.401)

IDAPA 58.01.01.401 .... Tier II Operating Permit

The application was submitted for a permit to construct (refer to the Permit to Construct section), and an optional Tier II operating permit has not been requested. Therefore, the procedures of IDAPA 58.01.01.400–410 were not applicable to this permitting action.

Visible Emissions (IDAPA 58.01.01.625)

IDAPA 58.01.01.625 .... Visible Emissions

The sources of PM_{10} emissions at this facility are subject to the State of Idaho visible emissions standard of 20% opacity. This requirement is assured by Permit Conditions 2.4 and 3.3.

Standards for New Sources (IDAPA 58.01.01.676)

IDAPA 58.01.01.676 .... Standards for New Sources

The fuel burning equipment located at this facility, with a maximum rated input of ten (10) million BTU per hour or more, are subject to a particulate matter limitation of 0.015 gr/dscf of effluent gas corrected to 3% oxygen by volume when combusting gaseous fuels. Fuel-Burning Equipment is defined as any furnace, boiler, apparatus, stack and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer. This requirement is assured by Permit Condition 2.3.

Title V Classification (IDAPA 58.01.01.300, 40 CFR Part 70)

IDAPA 58.01.01.301 .... Requirement to Obtain Tier I Operating Permit

Post project facility-wide emissions from this facility do not have a potential to emit greater than 100 tons per year for PM_{10}, SO_2, NO_X, CO, and VOC or 10 tons per year for any one HAP or 25 tons per year for all HAP combined as demonstrated previously in the Emissions Inventories Section of this analysis. Therefore, the facility is not a Tier I source in accordance with IDAPA 58.01.01.006 and the requirements of IDAPA 58.01.01.301 do not apply.

PSD Classification (40 CFR 52.21)

40 CFR 52.21 ....Prevention of Significant Deterioration of Air Quality

The facility is not a major stationary source as defined in 40 CFR 52.21(b)(1), nor is it undergoing any physical change at a stationary source not otherwise qualifying under paragraph 40 CFR 52.21(b)(1) as a major stationary source, that would constitute a major stationary source by itself as defined in 40 CFR 52. Therefore in accordance with 40 CFR 52.21(a)(2), PSD requirements are not applicable to this permitting action. The facility is not a designated facility as defined in 40 CFR 52.21(b)(1)(i)(a), and does not have facility-wide emissions of any criteria pollutant that exceed 250 T/yr.

NSPS Applicability (40 CFR 60)

The facility is subject to the requirements of 40 CFR 60 Subpart OOOO – Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Below is a breakdown of Subpart OOOO. DEQ is delegated this Subpart.

40 CFR 60, Subpart OOOO ....Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution

§60.5365 Am I subject to this subpart?

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (g) of this section for which you commence construction, modification or reconstruction after August 23, 2011.

(a) Each gas well affected facility, which is a single natural gas well.

The facility is not a gas well affected facility.

(b) Each centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals that is located between the wellhead and the 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 an affected facility under this subpart.

The facility has an internal reciprocating compressor/engine. The facility is not using a single centrifugal compressor using wet seals.

(c) Each reciprocating compressor affected facility, which is a single reciprocating compressor located between the wellhead and the 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 an affected facility under this subpart.

The facility is not subject to this portion of the rule as there are no single reciprocating compressors servicing a single well site.

(d)(1) For the oil production segment (between the wellhead and the point of custody transfer to an oil pipeline), each pneumatic controller affected facility, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 scfh.

The facility is not part of the oil production segment.

(2) For the natural gas production segment (between the wellhead and the point of custody transfer to the natural gas transmission and storage segment and not including natural gas processing plants), each pneumatic controller affected facility, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 scfh.

The facility is a natural gas processing plant.

(3) For natural gas processing plants, each pneumatic controller affected facility, which is a single continuous bleed natural gas-driven pneumatic controller.

The facility is not a natural gas processing plant subject to this rule.

(e) Each storage vessel affected facility, which is a single storage vessel located in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment, and has the potential for VOC emissions equal to or greater than 6 tpy as determined according to this section by October 15, 2013 for Group 1 storage vessels and by April 15, 2014, or 30 days after startup (whichever is later) for Group 2 storage vessels. A storage vessel affected facility that subsequently has its potential for VOC emissions decrease to less than 6 tpy shall remain an affected facility under this subpart. 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 specified in this section. 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 affected facility status, provided you comply with the requirements in paragraphs (e)(1) through (4) of this section.

(1) You meet the cover requirements specified in §60.5411(b).

(2) You meet the closed vent system requirements specified in §60.5411(c).

(3) You maintain records that document compliance with paragraphs (e)(1) and (2) of this section.

(4) 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 (e)(1) and (2) 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.

Emissions from storage vessel affected facilities satisfy any potentially applicable requirements.

(f) The group of all equipment, except compressors, within a process unit is an affected facility.

(1) Addition or replacement of equipment for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(2) 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 §§60.5400, 60.5401, 60.5402, 60.5421, and 60.5422 of this subpart 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 provisions of §§60.5400, 60.5401, 60.5402, 60.5421, and 60.5422 of this subpart.

(3) The equipment within a process unit of an affected facility located at onshore natural gas processing plants and described in paragraph (f) of this section are exempt from this subpart if they are subject to and controlled according to subparts VVa, GGG or GGGa of this part.

The facility is not an affected facility under this portion of the rule. The facility has no equipment that is subject to and controlled according to subparts VVa, GGG, or GGGa.

(g) Sweetening units located at onshore natural gas processing plants that process natural gas produced from either onshore or offshore wells.

(1) Each sweetening unit that processes natural gas is an affected facility; and

(2) Each sweetening unit that processes natural gas followed by a sulfur recovery unit is an affected facility.

(3) Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H_2S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in §60.5423(c) but are not required to comply with §§60.5405 through 60.5407 and §§60.5410(g) and 60.5415(g) of this subpart.

(4) Sweetening facilities producing acid gas that is completely reinjected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere are not subject to §§60.5405 through 60.5407, 60.5410(g), 60.5415(g), and 60.5423 of this subpart.

The facility does not have a sweetening unit.

(h) The following provisions apply to gas well facilities that are hydraulically refractured.

(1) A gas well facility that conducts a well completion operation following hydraulic refracturing is not an affected facility, provided that the requirements of §60.5375 are met. For purposes of this provision, the dates specified in §60.5375(a) do not apply, and such facilities, as of October 15, 2012, must meet the requirements of §60.5375(a)(1) through (4).

(2) A well completion operation following hydraulic refracturing at a gas well facility not conducted pursuant to §60.5375 is a modification to the gas well affected facility.

(3) Refracturing of a gas well facility does not affect the modification status of other equipment, process units, storage vessels, compressors, or pneumatic controllers located at the well site.

(4) A gas well facility initially constructed after August 23, 2011, is considered an affected facility regardless of this provision.

The facility is not a gas well affected facility under this subpart.

§60.5370 When must I comply with this subpart?

(a) You must be in compliance with the standards of this subpart no later than October 15, 2012 or upon startup, whichever is later.

(b) The provisions for exemption from compliance during periods of startup, shutdown and malfunctions provided for in 40 CFR 60.8(c) do not apply to this subpart.

(c) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

The facility must comply with this subpart upon startup.

§60.5375 What standards apply to gas well affected facilities?

The facility is not a gas well affected facility and therefore is not subject to the requirements in §60.5375.

§60.5380 What standards apply to centrifugal compressor affected facilities?

The facility is not a centrifugal compressor affected facility and therefore is not subject to the requirements in §60.5380.

§60.5385 What standards apply to reciprocating compressor affected facilities?

The facility is not a reciprocating compressor affected facility and therefore is not subject to the requirements in §60.5385.

§60.5390 What standards apply to pneumatic controller affected facilities?

For each pneumatic controller affected facility you must comply with the VOC standards, based on natural gas as a surrogate for VOC, 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 this requirement.

(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 affected facility 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 month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller, as required in §60.5420(c)(4)(ii).

(b)(1) Each pneumatic controller affected facility at a natural gas processing plant must have a bleed rate of zero.

(2) Each pneumatic controller affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller as required in §60.5420(c)(4)(iv).

(c)(1) Each pneumatic controller affected facility constructed, modified or reconstructed on or after October 15, 2013, 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 affected facility at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that controller as required in §60.5420(c)(4)(iii).

(d) You must demonstrate initial compliance with standards that apply to pneumatic controller affected facilities as required by §60.5410.

(e) You must demonstrate continuous compliance with standards that apply to pneumatic controller affected facilities as required by §60.5415.

(f) You must perform the required notification, recordkeeping, and reporting as required by §60.5420, except that you are not required to submit the notifications specified in §60.5420(a).

The facility does not currently have pneumatic controllers falling under these requirements. Should pneumatic controllers be installed, the controllers will be subject to the above requirements.

§60.5395 What standards apply to storage vessel affected facilities?

The facility is not a storage vessel affected facility.

§60.5400 What equipment leak standards apply to affected facilities at an onshore natural gas processing plant?

This section applies to the group of all equipment, except compressors, within a process unit.

(a) You must comply with the requirements of §§60.482-1a(a), (b), and (d), 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in §60.5401.

The facility must comply with these requirements. Below are the requirements of Subpart VVa as referenced above:

§60.482-1a Standards: General.

(a) Each owner or operator subject to the provisions of this subpart shall demonstrate compliance with the requirements of §§60.482-1a through 60.482-10a or §60.480a(e) for all equipment within 180 days of initial startup.

(b) Compliance with §§60.482-1a to 60.482-10a will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in §60.485a.

(d) Equipment that is in vacuum service is excluded from the requirements of §§60.482-2a through 60.482-10a if it is identified as required in §60.486a(e)(5).

§60.482-2a Standards: 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 §60.485a(b), except as provided in §60.482-1a(c) and (f) and 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 §60.482-1a(c) and 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, except as provided in §60.482-1a(f).

(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 §60.485a(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 §60.482-9a.

(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 §60.482-10a; 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 §60.485a(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 §60.486a(e)(1) and (2), 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 §60.485a(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 §60.482-10a, it is exempt from paragraphs (a) through (e) of this section.

(g) Any pump that is designated, as described in §60.486a(f)(1), 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.

§60.482-4a Standards: 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 §60.485a(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 §60.482-9a.

(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 §60.485a(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 §60.482-10a 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 §60.482-9a.

§60.482-5a Standards: Sampling connection systems.

(a) Each sampling connection system shall be equipped with a closed-purge, closed-loop, or closed-vent system, except as provided in §60.482-1a(c) and paragraph (c) of this section.

(b) Each closed-purge, closed-loop, or closed-vent system as required in paragraph (a) of this section shall comply with the requirements specified in paragraphs (b)(1) through (4) of this section.

(1) Gases displaced during filling of the sample container are not required to be collected or captured.

(2) Containers that are part of a closed-purge system must be covered or closed when not being filled or emptied.

(3) Gases remaining in the tubing or piping between the closed-purge system valve(s) and sample container valve(s) after the valves are closed and the sample container is disconnected are not required to be collected or captured.

(4) Each closed-purge, closed-loop, or closed-vent system shall be designed and operated to meet requirements in either paragraph (b)(4)(i), (ii), (iii), or (iv) of this section.

(i) Return the purged process fluid directly to the process line.

(ii) Collect and recycle the purged process fluid to a process.

(iii) Capture and transport all the purged process fluid to a control device that complies with the requirements of §60.482-10a.

(iv) Collect, store, and transport the purged process fluid to any of the following systems or facilities:

(A) A waste management unit as defined in 40 CFR 63.111, if the waste management unit is subject to and operated in compliance with the provisions of 40 CFR part 63, subpart G, applicable to Group 1 wastewater streams;

(B) A treatment, storage, or disposal facility subject to regulation under 40 CFR part 262, 264, 265, or 266;

(C) A facility permitted, licensed, or registered by a state to manage municipal or industrial solid waste, if the process fluids are not hazardous waste as defined in 40 CFR part 261;

(D) A waste management unit subject to and operated in compliance with the treatment requirements of 40 CFR 61.348(a), provided all waste management units that collect, store, or transport the purged process fluid to the treatment unit are subject to and operated in compliance with the management requirements of 40 CFR 61.343 through 40 CFR 61.347; or

(E) A device used to burn off-specification used oil for energy recovery in accordance with 40 CFR part 279, subpart G, provided the purged process fluid is not hazardous waste as defined in 40 CFR part 261.

(c) In-situ sampling systems and sampling systems without purges are exempt from the requirements of paragraphs (a) and (b) of this section.

§60.482-6a Standards: 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 §60.482-1a(c) and 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), (b), and (c) of this section.

(e) Open-ended valves or lines containing materials which would autocatalytically 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.

§60.482-7a Standards: 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 §60.485a(b) and shall comply with paragraphs (b) through (e) of this section, except as provided in paragraphs (f), (g), and (h) of this section, §60.482-1a(c) and (f), and §§60.483-1a and 60.483-2a.

(2) A valve that begins operation in gas/vapor service or light liquid service after the initial startup 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, §60.482-1a(c), and §§60.483-1a and 60.483-2a.

(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 §60.483-1a or §60.483-2a, count the new valve as leaking when calculating the percentage of valves leaking as described in §60.483-2a(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 §60.482-9a.

(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 §60.486a(e)(2), 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 §60.485a(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 Administrator.

(g) Any valve that is designated, as described in §60.486a(f)(1), 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 §60.486a(f)(2), 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:

(i) Becomes an affected facility through §60.14 or §60.15 and was constructed on or before January 5, 1981; or

(ii) 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.

§60.482-8a *Standards: 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 §60.485a(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 §60.482-9a.

(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 §§60.482-2a(c)(2) and 60.482-7a(e).

§60.482-9a Standards: Delay of repair.

(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 §60.482-10a.

(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.

§60.482-10a Standards: Closed vent systems and control devices.

(a) Owners or operators of closed vent systems and control devices used to comply with provisions of this subpart 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 percent or greater, or to an exit concentration of 20 parts per million by volume (ppmv), whichever is less stringent.

(c) Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 ppmv, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 °C.

(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 subpart 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 §60.485a(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 §60.485a(b); and

(ii) Conduct annual inspections according to the procedures in §60.485a(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 process unit within which the closed vent system is located becomes an affected facility through §§60.14 or 60.15, or 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 §60.486a(c).

(4) For each inspection conducted in accordance with §60.485a(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 subpart shall be operated at all times when emissions may be vented to them.

§60.482-11a Standards: 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 by the later of either 12 months after the compliance date or 12 months after initial startup. 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 §60.482-1a(c), §60.482-10a, 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 §60.485a(b) and, as applicable, §60.485a(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 §60.485a(b).

C_t = Total number of monitored connectors in the process unit or affected facility.

(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 §60.482-9a. A first attempt at repair as defined in this subpart shall be made no later than 5 calendar days after the leak is detected.

(e) Any connector that is designated, as described in §60.486a(f)(1), 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 the recordkeeping and reporting requirements of §§63.1038 and 63.1039. 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 subpart. Connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this subpart are identified as a group, and the number of connectors subject is indicated.

(b) You may elect to comply with the requirements of §§60.483-1a and 60.483-2a, as an alternative.

The facility may elect to comply with these requirements as an alternative. Below are the requirements of Subpart VVa as referenced above:

§60.483-1a 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 Administrator that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in §60.487a(d).

(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 Administrator.

(3) If a valve leak is detected, it shall be repaired in accordance with §60.482-7a(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 affected facility shall be monitored within 1 week by the methods specified in §60.485a(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 affected facility.

(d) Owners and operators who elect to comply with this alternative standard shall not have an affected facility with a leak percentage greater than 2.0 percent, determined as described in §60.485a(h).

§60.483-2a 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 Administrator before implementing one of the alternative work practices, as specified in §60.487(d)a.

(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 §60.482-7a.

(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 §60.482-7a but can again elect to use this section.

(5) The percent of valves leaking shall be determined as described in §60.485a(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 initial startup date for a process unit following one of the alternative standards in this section must be monitored in accordance with §60.482-7a(a)(2)(i) or (ii) before the provisions of this section can be applied to that valve.

(c) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of §60.5402 of this subpart.

(d) You must comply with the provisions of §60.485a of this part except as provided in paragraph (f) of this section.

The facility must comply with these requirements. Below are the requirements of Subpart VVa as referenced above:

§60.485a Test methods and procedures.

(a) In conducting the performance tests required in §60.8, 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, except as provided in §60.8(b).

(b) The owner or operator shall determine compliance with the standards in §§60.482-1a through 60.482-11a, 60.483a, and 60.484a as follows:

(1) 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 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 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 §60.486a(e)(7). Calculate the average algebraic difference between the three meter readings and the most recent calibration value. Divide this algebraic difference 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 minus the percent of negative drift/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 plus the percent of positive drift/divided by 100) may be re-monitored.

(c) The owner or operator shall determine compliance with the no-detectable-emission standards in §§60.482-2a(e), 60.482-3a(i), 60.482-4a, 60.482-7a(f), and 60.482-10a(e) as follows:

(1) The requirements of paragraph (b) shall apply.

(2) 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) Procedures that conform to the general methods in ASTM E260-73, 91, or 96, E168-67, 77, or 92, E169-63, 77, or 93 (incorporated by reference—see §60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.

(2) Organic compounds that are considered by the Administrator 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 Administrator 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. H_2O at 68 °F). Standard reference texts or ASTM D2879-83, 96, or 97 (incorporated by reference—see §60.17) 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. H_2O 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) Method 22 of appendix A-7 of this part shall be used to determine visible emissions.

(2) A thermocouple or any other equivalent device 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 m^4/(MJ-sec) (metric units) = 0.087 ft^4/(Btu-sec) (English units).*

(4) The net heating value (HT) 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) 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) (incorporated by reference-see §60.17) shall be used to determine the concentration of sample component "i."

(6) ASTM D2382-76 or 88 or D4809-95 (incorporated by reference-see §60.17) shall be used to determine the net heat of combustion of component "i" if published values are not available or cannot be calculated.

(7) 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 §60.483-1a or §60.483-2a 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 §60.482-7a(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.

(e) You must comply with the provisions of §§60.486a and 60.487a of this part except as provided in §§60.5401, 60.5421, and 60.5422 of this part.

The facility must comply with these requirements. Below are the requirements of Subpart VVa as referenced above:

§60.486a Recordkeeping requirements.

(a)(1) Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.

(2) An owner or operator of more than one affected facility subject to the provisions of this subpart may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

(3) The owner or operator shall record the information specified in paragraphs (a)(3)(i) through (v) of this section for each monitoring event required by §§60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a.

(i) Monitoring instrument identification.

(ii) Operator identification.

(iii) Equipment identification.

(iv) Date of monitoring.

(v) Instrument reading.

(b) When each leak is detected as specified in §§60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following requirements apply:

(1) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(2) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in §60.482-7a(c) and no leak has been detected during those 2 months.

(3) The identification on a connector may be removed after it has been monitored as specified in §60.482-11a(b)(3)(iv) and no leak has been detected during that monitoring.

(4) The identification on equipment, except on a valve or connector, may be removed after it has been repaired.

(c) When each leak is detected as specified in §§60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(1) 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.

(2) The date the leak was detected and the dates of each attempt to repair the leak.

(3) Repair methods applied in each attempt to repair the leak.

(4) Maximum instrument reading measured by Method 21 of appendix A-7 of this part at the time the leak is successfully repaired or determined to be nonrepairable, except when a pump is repaired by eliminating indications of liquids dripping.

(5) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(6) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(7) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(8) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(9) The date of successful repair of the leak.

(d) The following information pertaining to the design requirements for closed vent systems and control devices described in §60.482-10a shall be recorded and kept in a readily accessible location:

(1) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(2) The dates and descriptions of any changes in the design specifications.

(3) A description of the parameter or parameters monitored, as required in §60.482-10a(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.

(4) Periods when the closed vent systems and control devices required in §§60.482-2a, 60.482-3a, 60.482-4a, and 60.482-5a are not operated as designed, including periods when a flare pilot light does not have a flame.

(5) Dates of startups and shutdowns of the closed vent systems and control devices required in §§60.482-2a, 60.482-3a, 60.482-4a, and 60.482-5a.

(e) The following information pertaining to all equipment subject to the requirements in §§60.482-1a to 60.482- 11a shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for equipment subject to the requirements of this subpart.

(2)(i) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §§60.482-2a(e), 60.482-3a(i), and 60.482-7a(f).

(ii) The designation of equipment as subject to the requirements of §60.482-2a(e), §60.482-3a(i), or §60.482-7a(f) shall be signed by the owner or operator. Alternatively, the owner or operator may establish a mechanism with their permitting authority that satisfies this requirement.

(3) A list of equipment identification numbers for pressure relief devices required to comply with §60.482-4a.

(4)(i) The dates of each compliance test as required in §§60.482-2a(e), 60.482-3a(i), 60.482-4a, and 60.482-7a(f).

(ii) The background level measured during each compliance test.

(iii) The maximum instrument reading measured at the equipment during each compliance test.

(5) A list of identification numbers for equipment in vacuum service.

(6) A list of identification numbers for equipment that the owner or operator designates as operating in VOC service less than 300 hr/yr in accordance with §60.482-1a(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.

(7) The date and results of the weekly visual inspection for indications of liquids dripping from pumps in light liquid service.

(8) Records of the information specified in paragraphs (e)(8)(i) through (vi) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of Method 21 of appendix A-7 of this part and §60.485a(b).

(i) Date of calibration and initials of operator performing the calibration.

(ii) Calibration gas cylinder identification, certification date, and certified concentration.

(iii) Instrument scale(s) used.

(iv) 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 Method 21 of appendix A-7 of this part.

(v) Results of each calibration drift assessment required by §60.485a(b)(2) (i.e., instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).

(vi) If an owner or operator makes their own calibration gas, a description of the procedure used.

(9) The connector monitoring schedule for each process unit as specified in §60.482-11a(b)(3)(v).

(10) Records of each release from a pressure relief device subject to §60.482-4a.

(f) The following information pertaining to all valves subject to the requirements of §60.482-7a(g) and (h), all pumps subject to the requirements of §60.482-2a(g), and all connectors subject to the requirements of §60.482-11a(e) shall be recorded in a log that is kept in a readily accessible location:

(1) 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.

(2) 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.

(g) The following information shall be recorded for valves complying with §60.483-2a:

(1) A schedule of monitoring.

(2) The percent of valves found leaking during each monitoring period.

(h) The following information shall be recorded in a log that is kept in a readily accessible location:

(1) Design criterion required in §§60.482-2a(d)(5) and 60.482-3a(e)(2) and explanation of the design criterion; and

(2) Any changes to this criterion and the reasons for the changes.

(i) The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in §60.480a(d):

(1) An analysis demonstrating the design capacity of the affected facility,

(2) A statement listing the feed or raw materials and products from the affected facilities 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.

(j) 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.

(k) The provisions of §60.7(b) and (d) do not apply to affected facilities subject to this subpart.

§60.487a Reporting requirements.

(a) Each owner or operator subject to the provisions of this subpart shall submit semiannual reports to the Administrator beginning 6 months after the initial startup date.

(b) The initial semiannual report to the Administrator shall include the following information:

(1) Process unit identification.

(2) Number of valves subject to the requirements of §60.482-7a, excluding those valves designated for no detectable emissions under the provisions of §60.482-7a(f).

(3) Number of pumps subject to the requirements of §60.482-2a, excluding those pumps designated for no detectable emissions under the provisions of §60.482-2a(e) and those pumps complying with §60.482-2a(f).

(4) Number of compressors subject to the requirements of §60.482-3a, excluding those compressors designated for no detectable emissions under the provisions of §60.482-3a(i) and those compressors complying with §60.482-3a(h).

(5) Number of connectors subject to the requirements of §60.482-11a.

(c) All semiannual reports to the Administrator shall include the following information, summarized from the information in §60.486a:

(1) Process unit identification.

(2) For each month during the semiannual reporting period,

(i) Number of valves for which leaks were detected as described in §60.482-7a(b) or §60.483-2a,

(ii) Number of valves for which leaks were not repaired as required in §60.482-7a(d)(1),

(iii) Number of pumps for which leaks were detected as described in §60.482-2a(b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),

(iv) Number of pumps for which leaks were not repaired as required in §60.482-2a(c)(1) and (d)(6),

(v) Number of compressors for which leaks were detected as described in §60.482-3a(f),

(vi) Number of compressors for which leaks were not repaired as required in §60.482-3a(g)(1),

(vii) Number of connectors for which leaks were detected as described in §60.482-11a(b)

(viii) Number of connectors for which leaks were not repaired as required in §60.482-11a(d), and

(ix)-(x) [Reserved]

(xi) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(3) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(4) Revisions to items reported according to paragraph (b) of this section if changes have occurred since the initial report or subsequent revisions to the initial report.

(d) An owner or operator electing to comply with the provisions of §§60.483-1a or 60.483-2a shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.

(e) An owner or operator shall report the results of all performance tests in accordance with §60.8 of the General Provisions. The provisions of §60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that an owner or operator must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.

(f) The requirements of paragraphs (a) through (c) of this section remain in force until and unless EPA, in delegating enforcement authority to a state under section 111(c) of the CAA, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of the obligation to comply with the requirements of paragraphs (a) through (c) of this section, provided that they comply with the requirements established by the state.

(f) You must use the following provision instead of §60.485a(d)(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 (incorporated by reference as specified in §60.17) must be used.

The facility must comply with this requirement.

§60.5401 — *What are the exceptions to the equipment leak standards for affected facilities at onshore natural gas processing plants?*

(a) You may comply with the following exceptions to the provisions of §60.5400(a) and (b).

(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 §60.485a(b) except as provided in §60.5400(c) and in paragraph (b)(4) of this section, and §60.482-4a(a) through (c) of subpart VVa.

(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 §60.482-9a.

(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 nonfractionating 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 §60.482-4a(b)(1) of subpart VVa.

(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) Sampling connection systems are exempt from the requirements of §60.482-5a.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service that are located at a nonfractionating 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 §§60.482-2a(a)(1) and 60.482-7a(a), and paragraph (b)(1) of this section.

(e) Pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of §§60.482-2a(a)(1), 60.482-7a(a), and paragraph (b)(1) of this section.

(f) An owner or operator may use the following provisions instead of §60.485a(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 (incorporated by reference as specified in §60.17).

(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 (incorporated by reference as specified in §60.17).

(g) An owner or operator may use the following provisions instead of §60.485a(b)(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 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 §60.486a(e)(8). Divide these readings by the initial calibration values for each scale 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 minus the percent of negative drift/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 plus the percent of positive drift/divided by 100) may be re-monitored.

The facility may comply with these exceptions to the above listed provisions.

§60.5402 *What are the alternative emission limitations for equipment leaks from onshore natural gas processing plants?*

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under any design, equipment, work practice or operational standard, the Administrator will publish, in the FEDERAL REGISTER, a notice permitting the use of that alternative means for the purpose of compliance with that standard. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

(b) Any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing.

(c) The Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment.

(d) The Administrator will treat applications under this section according to the following criteria, except in cases where the Administrator concludes that other criteria are appropriate:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section.

(2) If the applicant is an owner or operator of an affected facility, the applicant must commit in writing to operate and maintain the alternative means so as to achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under the design, equipment, work practice or operational standard.

The facility may comply with these alternative emission limitations.

§60.5405 *What standards apply to sweetening units at onshore natural gas processing plants?*

The facility does not have a sweetening unit and therefore these requirements are not applicable.

§60.5406 *What test methods and procedures must I use for my sweetening units affected facilities at onshore natural gas processing plants?*

The facility does not have a sweetening unit and therefore these requirements are not applicable.

§60.5407 *What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?*

The facility does not have a sweetening unit and therefore these requirements are not applicable.

§60.5408 *What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?*

The facility does not have a sweetening unit and therefore these requirements are not applicable.

§60.5410 How do I demonstrate initial compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?

You must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (i) of this section. The initial compliance period begins on October 15, 2012, or upon initial startup, whichever is later, and ends no later than one year after the initial startup date for your affected facility or no later than one year after October 15, 2012. The initial compliance period may be less than one full year.

(a) To achieve initial compliance with the standards for each well completion operation conducted at your gas well affected facility you must comply with paragraphs (a)(1) through (a)(4) of this section.

(1) You must submit the notification required in §60.5420(a)(2).

(2) You must submit the initial annual report for your well affected facility as required in §60.5420(b).

(3) You must maintain a log of records as specified in §60.5420(c)(1)(i) through (iv) for each well completion operation conducted during the initial compliance period.

(4) For each gas well affected facility subject to both §60.5375(a)(1) and (3), as an alternative to retaining the records specified in §60.5420(c)(1)(i) through (iv), you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file showing the equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to the gas flow line and the completion combustion device (if applicable) connected to and operating at each gas well completion operation that occurred during the initial compliance period. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the equipment connected and operating at each well completion operation with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

(b)(1) To achieve initial compliance with standards for your centrifugal compressor affected facility you must reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater as required by §60.5380 and as demonstrated by the requirements of §60.5413.

(2) 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 §60.5411(b) that is connected through a closed vent system that meets the requirements of §60.5411(a) and is routed to a control device that meets the conditions specified in §60.5412(a), (b) and (c). 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 must conduct an initial performance test as required in §60.5413 within 180 days after initial startup or by October 15, 2012, whichever is later, and you must comply with the continuous compliance requirements in §60.5415(b)(1) through (3).

(4) You must conduct the initial inspections required in §60.5416(a) and (b).

(5) You must install and operate the continuous parameter monitoring systems in accordance with §60.5417(a) through (g), as applicable.

(6) You must submit the notifications required in 60.7(a)(1), (3), and (4).

(7) You must submit the initial annual report for your centrifugal compressor affected facility as required in §60.5420(b)(3) for each centrifugal compressor affected facility.

(8) You must maintain the records as specified in §60.5420(c)(2).

(c) To achieve initial compliance with the standards for each reciprocating compressor affected facility you must comply with paragraphs (c)(1) through (4) of this section.

(1) During the initial compliance period, you must continuously monitor the number of hours of operation or track the number of months since the last rod packing replacement.

(2) [Reserved]

(3) You must submit the initial annual report for your reciprocating compressor as required in §60.5420(b).

(4) You must maintain the records as specified in §60.5420(c)(3) for each reciprocating compressor affected facility.

(d) To achieve initial compliance with emission standards for your pneumatic controller affected facility you must comply with the requirements specified in paragraphs (d)(1) through (6) of this section, as applicable.

(1) You must demonstrate initial compliance by maintaining records as specified in §60.5420(c)(4)(ii) of your determination that the use of a pneumatic controller affected facility with a bleed rate greater than 6 standard cubic feet of gas per hour is required as specified in §60.5390(a).

(2) You own or operate a pneumatic controller affected facility located at a natural gas processing plant and your pneumatic controller is driven by a gas other than natural gas and therefore emits zero natural gas.

(3) You own or operate a pneumatic controller affected facility 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.

(4) You must tag each new pneumatic controller affected facility according to the requirements of §60.5390(b)(2) or (c)(2).

(5) You must include the information in paragraph (d)(1) of this section and a listing of the pneumatic controller affected facilities specified in paragraphs (d)(2) and (3) of this section in the initial annual report submitted for your pneumatic controller affected facilities constructed, modified or reconstructed during the period covered by the annual report according to the requirements of §60.5420(b).

(6) You must maintain the records as specified in §60.5420(c)(4) for each pneumatic controller affected facility.

(e) [Reserved]

(f) For affected facilities at onshore natural gas processing plants, initial compliance with the VOC requirements is demonstrated if you are in compliance with the requirements of §60.5400.

(g) For sweetening unit affected facilities at onshore natural gas processing plants, initial compliance is demonstrated according to paragraphs (g)(1) through (3) of this section.

(1) To determine compliance with the standards for SO_2 *specified in §60.5405(a), during the initial performance test as required by §60.8, the minimum required sulfur dioxide emission reduction efficiency* (Z_i) *is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology as specified in paragraphs (g)(1)(i) and (ii) of this section.*

(i) If R Z_i, *your affected facility is in compliance.*

(ii) If R Z_i, *your affected facility is not in compliance.*

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in §60.5406(c)(1).

(3) You have submitted the results of paragraphs (g)(1) and (2) of this section in the initial annual report submitted for your sweetening unit affected facilities at onshore natural gas processing plants.

(h) For each storage vessel affected facility, you must comply with paragraphs (h)(1) through (5) of this section. For a Group 1 storage vessel affected facility, you must demonstrate initial compliance by April 15, 2015, except as otherwise provided in paragraph (i) of this section. For a Group 2 storage vessel affected facility, you must demonstrate initial compliance by April 15, 2014, or within 60 days after startup, whichever is later.

(1) You must determine the potential VOC emission rate as specified in §60.5365(e).

(2) You must reduce VOC emissions in accordance with §60.5395(d).

(3) If you use a control device to reduce emissions, or if you route emissions to a process, you must demonstrate initial compliance by meeting the requirements in §60.5395(e).

(4) You must submit the information required for your storage vessel affected facility as specified in §60.5420(b).

(5) You must maintain the records required for your storage vessel affected facility, as specified in §60.5420(c)(5) through (8) and §60.5420(c)(12) and (13) for each storage vessel affected facility.

(i) For each Group 1 storage vessel affected facility, you must submit the notification specified in §60.5395(b)(2) with the initial annual report specified in §60.5420(b)(6).

The facility is affected and must comply with two categories under the rule, pneumatic controller affected facilities and equipment leaks.

§60.5411	*What additional requirements must I meet to determine initial compliance for my covers and closed vent systems routing materials from storage vessels and centrifugal compressor wet seal degassing systems?*

Emissions from storage vessel affected facilities will satisfy any potentially applicable requirements.

§60.5412	*What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my storage vessel or centrifugal compressor affected facility?*

Emissions from storage vessel affected facilities will satisfy any potentially applicable requirements.

§60.5413	*What are the performance testing procedures for control devices used to demonstrate compliance at my storage vessel or centrifugal compressor affected facility?*

Emissions from storage vessel affected facilities will satisfy any potentially applicable requirements.

§60.5415	*How do I demonstrate continuous compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my stationary reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?*

(a) For each gas well affected facility, you must demonstrate continuous compliance by submitting the reports required by §60.5420(b) and maintaining the records for each completion operation specified in §60.5420(c)(1).

(b) For each centrifugal compressor affected facility, you must demonstrate continuous compliance according to paragraphs (b)(1) through (3) 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 §60.5412(a) using the procedures specified in paragraphs (b)(2)(i) through (vii) of this section. If you use a condenser as the control device to achieve the requirements specified in §60.5412(a)(2), you must demonstrate compliance according to paragraph (b)(2)(viii) of this section. You may switch between compliance with paragraphs (b)(2)(i) through (vii) of this section and compliance with paragraph (b)(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, as required in §60.5420(b), following the change.

(i) You must operate below (or above) the site specific maximum (or minimum) parameter value established according to the requirements of §60.5417(f)(1).

(ii) You must calculate the daily average of the applicable monitored parameter in accordance with §60.5417(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 (b)(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 (b)(2)(i) of this section. When performance testing of a combustion control device is conducted by the device manufacturer as specified in §60.5413(d), compliance with the operating parameter limit is achieved when the criteria in §60.5413(e) are met.

(iv) You must operate the continuous monitoring system required in §60.5417 at all times the affected 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 §60.5412(a) and you demonstrate compliance using the test procedures specified in §60.5413(b), you must comply with paragraphs (b)(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 2 minutes during any hour. A visible emissions test using section 11. of Method 22, 40 CFR part 60, appendix A, must be performed each calendar quarter. The observation period must be 1 hour and must be conducted according to section 11. of EPA Method 22, 40 CFR part 60, appendix A.

(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 repairs 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, visual observation as described in paragraph (b)(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 §60.5412(a)(2), you must demonstrate compliance using the procedures in paragraphs (b)(2)(viii)(A) through (E) of this section.

(A) You must establish a site-specific condenser performance curve according to §60.5417(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with §60.5417(e).

(C) You must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (b)(2)(viii)(B) of this section and the condenser performance curve established under paragraph (b)(2)(viii)(A) of this section.

(D) Except as provided in paragraphs (b)(2)(viii)(D)(1) and (2) of this section, at the end of each operating day, you must calculate the 365-day rolling average TOC emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (b)(2)(viii)(C) of this section.

(1) After the compliance dates specified in §60.5370, 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 after the compliance dates. 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 after the compliance date specified in §60.5370, you must calculate the average TOC emission reduction as the TOC emission reduction averaged over the number of days between the current day and the applicable compliance date. 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 (b)(2)(viii)(D) of this section is equal to or greater than 95.0 percent.

(3) You must submit the annual report required by 60.5420(b) and maintain the records as specified in §60.5420(c)(2).

(c) For each reciprocating compressor affected facility, you must demonstrate continuous compliance according to paragraphs (c)(1) through (3) of this section.

(1) You must continuously monitor the number of hours of operation for each reciprocating compressor affected facility or track the number of months since initial startup, or October 15, 2012, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) You must submit the annual report as required in §60.5420(b) and maintain records as required in §60.5420(c)(3).

(3) You must replace the reciprocating compressor rod packing 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.

(d) For each pneumatic controller affected facility, you must demonstrate continuous compliance according to paragraphs (d)(1) through (3) of this section.

(1) You must continuously operate the pneumatic controllers as required in §60.5390(a), (b), or (c).

(2) You must submit the annual report as required in §60.5420(b).

(3) You must maintain records as required in §60.5420(c)(4).

(e) You must demonstrate continuous compliance according to paragraph (e)(3) of this section for each storage vessel affected facility, for which you are using a control device or routing emissions to a process to meet the requirement of §60.5395(d)(1).

(1) [Reserved]

(2) [Reserved]

(3) For each storage vessel affected facility, you must comply with paragraphs (e)(3)(i) and (ii) of this section.

(i) You must reduce VOC emissions as specified in §60.5395(d).

(ii) For each control device installed to meet the requirements of §60.5395(d), you must demonstrate continuous compliance with the performance requirements of §60.5412(d) for each storage vessel affected facility using the procedure specified in paragraph (e)(3)(ii)(A) and either (e)(3)(ii)(B) or (e)(3)(ii)(C) of this section.

(A) You must comply with §60.5416(c) for each cover and closed vent system.

(B) You must comply with §60.5417(h) for each control device.

(C) Each closed vent system that routes emissions to a process must be operated as specified in §60.5411(c)(2).

(f) For affected facilities at onshore natural gas processing plants, continuous compliance with VOC requirements is demonstrated if you are in compliance with the requirements of §60.5400.

(g) For each sweetening unit affected facility at onshore natural gas processing plants, you must demonstrate continuous compliance with the standards for SO_2 specified in §60.5405(b) according to paragraphs (g)(1) and (2) of this section.

(1) The minimum required SO_2 emission reduction efficiency (Z_c) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology.

(i) If R Z_c, your affected facility is in compliance.

(ii) If R Z_c, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in §60.5406(c)(1).

(h) Affirmative defense for violations of emission standards during malfunction. In response to an action to enforce the standards set forth in §§60.5375, 60.5380, 60.5385, 60.5390, 60.5395, 60.5400, and 60.5405, you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at §60.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in §60.5415(h)(2), and must prove by a preponderance of evidence that:

(i) The violation:

(A) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and

(B) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(C) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(D) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when a violation occurred. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(iv) If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(v) All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment and human health; and

(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(vii) All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and

(viii) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(ix) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(2) Report. The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (h)(1) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

The facility is affected and must comply with two categories under the rule, pneumatic controller affected facilities and equipment leaks.

§60.5416	*What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my storage vessel and centrifugal compressor affected facility?*

Emissions from storage vessel affected facilities will satisfy any potentially applicable requirements.

§60.5417	*What are the continuous control device monitoring requirements for my storage vessel or centrifugal compressor affected facility?*

Emissions from storage vessel affected facilities will satisfy any potentially applicable requirements.

§60.5420	*What are my notification, reporting, and recordkeeping requirements?*

(a) You must submit the notifications according to paragraphs (a)(1) and (2) of this section if you own or operate one or more of the affected facilities specified in §60.5365 that was constructed, modified, or reconstructed during the reporting period.

(1) If you own or operate a gas well, pneumatic controller, centrifugal compressor, reciprocating compressor or storage vessel affected facility you are not required to submit the notifications required in §60.7(a)(1), (3), and (4).

(2)(i) If you own or operate a gas well affected facility, you must submit a notification to the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the API well number, the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. You may submit the notification in writing or in electronic format.

(ii) If you are subject to state regulations that require advance notification of well completions and you have met those notification requirements, then you are considered to have met the advance notification requirements of paragraph (a)(2)(i) of this section.

(b) Reporting requirements. You must submit annual reports containing the information specified in paragraphs (b)(1) through (6) of this section to the Administrator and performance test reports as specified in paragraph (b)(7) or (8) of this section. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to §60.5410. Subsequent annual reports are due no later than same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (6) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period.

(1) The general information specified in paragraphs (b)(1)(i) through (iv) of this section.

(i) The company name and address of the affected facility.

(ii) An identification of each affected facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

(iv) A certification by a responsible 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.

(2) For each gas well affected facility, the information in paragraphs (b)(2)(i) through (ii) of this section.

(i) Records of each well completion operation as specified in paragraph (c)(1)(i) through (iv) of this section for each gas well affected facility conducted during the reporting period. In lieu of submitting the records specified in paragraph (c)(1)(i) through (iv), the owner or operator may submit a list of the well completions with hydraulic fracturing completed during the reporting period and the records required by paragraph (c)(1)(v) of this section for each well completion.

(ii) Records of deviations specified in paragraph (c)(1)(ii) of this section that occurred during the reporting period.

(3) For each centrifugal compressor affected facility, the information specified in paragraphs (b)(3)(i) and (ii) of this section.

(i) An identification of each centrifugal compressor using a wet seal system constructed, modified or reconstructed during the reporting period.

(ii) Records of deviations specified in paragraph (c)(2) of this section that occurred during the reporting period.

(iii) If required to comply with §60.5380(a)(1), the records specified in paragraphs (c)(6) through (11) of this section.

(4) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(4)(i) through (ii) of this section.

(i) The cumulative number of hours of operation or the number of months since initial startup, since October 15, 2012, or since the previous reciprocating compressor rod packing replacement, whichever is later.

(ii) Records of deviations specified in paragraph (c)(3)(iii) of this section that occurred during the reporting period.

(5) For each pneumatic controller affected facility, the information specified in paragraphs (b)(5)(i) through (iii) of this section.

(i) An identification of each pneumatic controller constructed, modified or reconstructed during the reporting period, including the identification information specified in §60.5390(b)(2) or (c)(2).

(ii) If applicable, documentation that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than 6 standard cubic feet per hour are required and the reasons why.

(iii) Records of deviations specified in paragraph (c)(4)(v) of this section that occurred during the reporting period.

(6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) through (vii) of this section.

(i) An identification, including the location, of each storage vessel affected facility for which construction, modification or reconstruction commenced during the reporting period. 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.

(ii) Documentation of the VOC emission rate determination according to §60.5365(e).

(iii) Records of deviations specified in paragraph (c)(5)(iii) of this section that occurred during the reporting period.

(iv) You must submit a notification identifying each Group 1 storage vessel affected facility in your initial annual report. You must include the location of the storage vessel, 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) A statement that you have met the requirements specified in §60.5410(h)(2) and (3).

(vi) You must identify each storage vessel affected facility that is removed from service during the reporting period as specified in §60.5395(f)(1).

(vii) You must identify each storage vessel affected facility for which operation resumes during the reporting period as specified in §60.5395(f)(2)(iii).

(7)(i) Within 60 days after the date of completing each performance test (see §60.8 of this part) as required by this subpart, except testing conducted by the manufacturer as specified in §60.5413(d), you must submit the results of the performance tests required by this subpart to the EPA as follows. You must use the latest version of the EPA's Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/index.html) existing at the time of the performance test to generate a submission package file, which documents the performance test. You must then submit the file generated by the ERT through the EPA's Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed by logging in to the EPA's Central Data Exchange (CDX) (https://cdx.epa.gov/). Only data collected using test methods supported by the ERT as listed on the ERT Web site are subject to this requirement for submitting reports electronically. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test to the Administrator at the appropriate address listed in §60.4.

(ii) All reports, except as specified in paragraph (b)(8) of this section, required by this subpart not subject to the requirements in paragraph (a)(2)(i) of this section must be sent to the Administrator at the appropriate address listed in §60.4 of this part. The Administrator or the delegated authority may request a report in any form suitable for the specific case (e.g., by commonly used electronic media such as Excel spreadsheet, on CD or hard copy).

(8) For enclosed combustors tested by the manufacturer in accordance with §60.5413(d), an electronic copy of the performance test results required by §60.5413(d) 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/.

(c) Recordkeeping requirements. You must maintain the records identified as specified in §60.7(f) and in paragraphs (c)(1) through (13) of this section. All records required by this subpart must be maintained either onsite or at the nearest local field office for at least 5 years.

(1) The records for each gas well affected facility as specified in paragraphs (c)(1)(i) through (v) of this section.

(i) Records identifying each well completion operation for each gas well affected facility;

(ii) Records of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in §60.5375.

(iii) Records required in §60.5375(b) or (f) for each well completion operation conducted for each gas well affected facility that occurred during the reporting period. You must maintain the records specified in paragraphs (c)(1)(iii)(A) and (B) of this section.

(A) For each gas well affected facility required to comply with the requirements of §60.5375(a), you must record: The location of the well; the API well number; the duration of flowback; duration of recovery to the flow line; duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours of time.

(B) For each gas well affected facility required to comply with the requirements of §60.5375(f), you must maintain the records specified in paragraph (c)(1)(iii)(A) of this section except that you do not have to record the duration of recovery to the flow line.

(iv) For each gas well facility for which you claim an exception under §60.5375(a)(3), you must record: The location of the well; the API well number; the specific exception claimed; the starting date and ending date for the period the well operated under the exception; and an explanation of why the well meets the claimed exception.

(v) For each gas well affected facility required to comply with both §60.5375(a)(1) and (3), if you are using a digital photograph in lieu of the records required in paragraphs (c)(1)(i) through (iv) of this section, you must retain the records of the digital photograph as specified in §60.5410(a)(4).

(2) For each centrifugal compressor affected facility, you must maintain records of deviations in cases where the centrifugal compressor was not operated in compliance with the requirements specified in §60.5380.

(3) For each reciprocating compressors affected facility, you must maintain the records in paragraphs (c)(3)(i) through (iii) of this section.

(i) Records of the cumulative number of hours of operation or number of months since initial startup or October 15, 2012, or the previous replacement of the reciprocating compressor rod packing, whichever is later.

(ii) Records of the date and time of each reciprocating compressor rod packing replacement.

(iii) Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in §60.5385.

(4) For each pneumatic controller affected facility, you must maintain the records identified in paragraphs (c)(4)(i) through (v) of this section.

(i) Records of the date, location and manufacturer specifications for each pneumatic controller constructed, modified or reconstructed.

(ii) Records of the demonstration that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than the applicable standard are required and the reasons why.

(iii) If the pneumatic controller is not located at a natural gas processing plant, records of the manufacturer's specifications indicating that the controller is designed such that natural gas bleed rate is less than or equal to 6 standard cubic feet per hour.

(iv) If the pneumatic controller is located at a natural gas processing plant, records of the documentation that the natural gas bleed rate is zero.

(v) Records of deviations in cases where the pneumatic controller was not operated in compliance with the requirements specified in §60.5390.

(5) Except as specified in paragraph (c)(5)(v) of this section, for each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) through (iv) of this section.

(i) If required to reduce emissions by complying with §60.5395(d)(1), the records specified in §§60.5420(c)(6) through (8), §60.5416(c)(6)(ii), and §60.6516(c)(7)(ii) of this subpart.

(ii) Records of each VOC emissions determination for each storage vessel affected facility made under §60.5365(e) including identification of the model or calculation methodology used to calculate the VOC emission rate.

(iii) Records of deviations in cases where the storage vessel was not operated in compliance with the requirements specified in §§60.5395, 60.5411, 60.5412, and 60.5413, as applicable.

(iv) 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, will be added to the count towards the number of consecutive days.

(v) You must maintain records of the identification and location of each storage vessel affected facility.

(6) Records of each closed vent system inspection required under §60.5416(a)(1) for centrifugal compressors or §60.5416(c)(1) for storage vessels.

(7) A record of each cover inspection required under §60.5416(a)(3) for centrifugal compressors or §60.5416(c)(2) for storage vessels.

(8) If you are subject to the bypass requirements of §60.5416(a)(4) for centrifugal compressors or §60.5416(c)(3) for storage vessels, 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.

(9) If you are subject to the closed vent system no detectable emissions requirements of §60.5416(b) for centrifugal compressors, a record of the monitoring conducted in accordance with §60.5416(b).

(10) For each centrifugal compressor affected facility, records of the schedule for carbon replacement (as determined by the design analysis requirements of §60.5413(c)(2) or (3)) and records of each carbon replacement as specified in §60.5412(c)(1).

(11) For each centrifugal compressor subject to the control device requirements of §60.5412(a), (b), and (c), 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.

(12) For each carbon adsorber installed on storage vessel affected facilities, records of the schedule for carbon replacement (as determined by the design analysis requirements of §60.5412(d)(2)) and records of each carbon replacement as specified in §60.5412(c)(1).

(13) For each storage vessel affected facility subject to the control device requirements of §60.5412(c) and (d), you must maintain records of the inspections, including any corrective actions taken, the manufacturers' operating instructions, procedures and maintenance schedule as specified in §60.5417(h). You must maintain records of EPA Method 22, 40 CFR part 60, appendix A, section 11 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. Manufacturer's operating instructions, procedures and maintenance schedule must be available for inspection.

The facility must comply with the applicable provisions upon startup of the facility.

§60.5421 *What are my additional recordkeeping requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?*

(a) You must comply with the requirements of paragraph (b) of this section in addition to the requirements of §60.486a.

(b) The following recordkeeping requirements apply to pressure relief devices subject to the requirements of §60.5401(b)(1) of this subpart.

(1) When each leak is detected as specified in §60.5401(b)(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.

(2) When each leak is detected as specified in §60.5401(b)(2), the following information must 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.

(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) "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.

(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.

(x) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §60.482-4a(a). The designation of equipment subject to the provisions of §60.482-4a(a) must be signed by the owner or operator.

The facility must comply with the provisions upon startup of the facility.

§60.5422 *What are my additional reporting requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?*

(a) You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of §60.487a(a), (b), (c)(2)(i) through (iv), and (c)(2)(vii) through (viii).

(b) An owner or operator must include the following information in the initial semiannual report in addition to the information required in §60.487a(b)(1) through (4): Number of pressure relief devices subject to the requirements of §60.5401(b) except for those pressure relief devices designated for no detectable emissions under the provisions of §60.482-4a(a) and those pressure relief devices complying with §60.482-4a(c).

(c) An owner or operator must include the following information in all semiannual reports in addition to the information required in §60.487a(c)(2)(i) through (vi):

(1) Number of pressure relief devices for which leaks were detected as required in §60.5401(b)(2); and

(2) Number of pressure relief devices for which leaks were not repaired as required in §60.5401(b)(3).

The facility must comply with the provisions upon startup of the facility.

§60.5423 *What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?*

The facility does not have a sweetening unit and therefore these requirements are not applicable.

§60.5425 *What part of the General Provisions apply to me?*

Table 3 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

Table 3 to Subpart OOOO of Part 60—Applicability of General Provisions to Subpart OOOO

As stated in §60.5425, you must comply with the following applicable General Provisions:

General provisions citation	*Subject of citation*	*Applies to subpart?*	*Explanation*
§60.1	*General applicability of the General Provisions*	*Yes.*	
§60.2	*Definitions*	*Yes*	*Additional terms defined in §60.5430.*
§60.3	*Units and abbreviations*	*Yes.*	
§60.4	*Address*	*Yes.*	
§60.5	*Determination of construction or modification*	*Yes.*	
§60.6	*Review of plans*	*Yes.*	
§60.7	*Notification and record keeping*	*Yes*	*Except that §60.7 only applies as specified in §60.5420(a).*
§60.8	*Performance tests*	*Yes*	*Performance testing is required for control devices used on storage vessels and centrifugal compressors.*
§60.9	*Availability of information*	*Yes.*	
§60.10	*State authority*	*Yes.*	
§60.11	*Compliance with standards and maintenance requirements*	*No*	*Requirements are specified in subpart OOOO.*
§60.12	*Circumvention*	*Yes.*	
§60.13	*Monitoring requirements*	*Yes*	*Continuous monitors are required for storage vessels.*
§60.14	*Modification*	*Yes.*	
§60.15	*Reconstruction*	*Yes.*	
§60.16	*Priority list*	*Yes.*	
§60.17	*Incorporations by reference*	*Yes.*	
§60.18	*General control device requirements*	*Yes*	*Except that §60.18 does not apply to flares.*
§60.19	*General notification and reporting requirement*		

The facility will operate one compressor engine that may be subject to the requirements of 40 CFR 60 Subpart JJJJ depending on date of manufacture. The compressor IC engine is a 610 bhp natural gas-fired engine. Below is a breakdown of Subpart JJJJ. DEQ is delegated this Subpart.

40 CFR 60, Subpart JJJJ ....Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

§60.4230 *Am I subject to this subpart?*

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary spark ignition (SI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (6) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(4) Owners and operators of stationary SI ICE that commence construction after June 12, 2006, where the stationary SI ICE are manufactured:

(i) On or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);

(6) The provisions of §60.4236 of this subpart are applicable to all owners and operators of stationary SI ICE that commence construction after June 12, 2006.

The applicable IC engine is a stationary spark ignition engine that may be subject to the Subpart if they commence construction after June 12, 2006.

§60.4231 What emission standards must I meet if I am a manufacturer of stationary SI internal combustion engines or equipment containing such engines?

The facility is not an engine manufacturer and therefore these requirements do not apply.

§60.4232 How long must my engines meet the emission standards if I am a manufacturer of stationary SI internal combustion engines?

The facility is not an engine manufacturer and therefore these requirements do not apply.

§60.4233 What emission standards must I meet if I am an owner or operator of a stationary SI internal combustion engine?

(e) Owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) must comply with the emission standards in Table 1 to this subpart for their stationary SI ICE. For owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 100 HP (except gasoline and rich burn engines that use LPG) manufactured prior to January 1, 2011 that were certified to the certification emission standards in 40 CFR part 1048 applicable to engines that are not severe duty engines, if such stationary SI ICE was certified to a carbon monoxide (CO) standard above the standard in Table 1 to this subpart, then the owners and operators may meet the CO certification (not field testing) standard for which the engine was certified.

Table 1 to Subpart JJJJ of Part 60—NO_X, CO, and VOC Emission Standards for Stationary Non-Emergency SI Engines ≥100 HP (Except Gasoline and Rich Burn LPG), Stationary SI Landfill/Digester Gas Engines, and Stationary Emergency Engines >25 HP

Engine type and fuel	Maximum engine power	Manufacture date	Emission standards[a]					
			g/HP-hr			ppmvd at 15% O_2		
			NO_X	CO	VOC[d]	NO_X	CO	VOC[d]
Non-Emergency SI Natural Gas and Non-Emergency SI Lean Burn LPG (except lean burn 500≤HP<1,350)	HP≥500	7/1/2007	2.0	4.0	1.0	160	540	86
	HP≥500	7/1/2010	1.0	2.0	0.7	82	270	60

[a]Owners and operators of stationary non-certified SI engines may choose to comply with he emission standards in units of either g/HP-hr or ppmvd at 15 percent O_2.

[b]Owners and operators of new or reconstructed non-emergency lean bum SI stationary engines with a site rating of greater than or equal to 250 brake HP located at a major source that are meeting the requirements of 40 CFR part 63, subpart ZZZZ, Table 2a do not have to comply with the CO emission standards of Table 1 of this subpart.

[c]The emission standards applicable to emergency engines between 25 HP and 130 HP are in terms of NO_X + HC.

[d]For purposes of this subpart, when calculating emissions of volatile organic compounds, emissions of formaldehyde should not be included.

The applicable IC engine shall comply with the emission standards as shown above in Table 1 to the Subpart.

§60.4234 *How long must I meet the emission standards if I am an owner or operator of a stationary SI internal combustion engine?*

Owners and operators of stationary SI ICE must operate and maintain stationary SI ICE that achieve the emission standards as required in §60.4233 over the entire life of the engine.

The applicable IC engine must meet the emission standards over the entire life of the engine.

§60.4236 *What is the deadline for importing or installing stationary SI ICE produced in previous model years?*

(b) After July 1, 2009, owners and operators may not install stationary SI ICE with a maximum engine power of greater than or equal to 500 HP that do not meet the applicable requirements in §60.4233, except that lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP that do not meet the applicable requirements in §60.4233 may not be installed after January 1, 2010.

The applicable IC engine will be installed after July 1, 2009 and will have a maximum engine power less than 1,350 HP.

§60.4237 *What are the monitoring requirements if I am an owner or operator of an emergency stationary SI internal combustion engine?*

The applicable IC engine is not an emergency engine and therefore these requirements do not apply.

§60.4238 *What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines ≤19 KW (25 HP) or a manufacturer of equipment containing such engines?*

The facility is not an engine manufacturer and therefore these requirements do not apply.

§60.4239 *What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that use gasoline or a manufacturer of equipment containing such engines?*

The facility is not an engine manufacturer and therefore these requirements do not apply.

§60.4240 *What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that are rich burn engines that use LPG or a manufacturer of equipment containing such engines?*

The facility is not an engine manufacturer and therefore these requirements do not apply.

§60.4241 *What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines participating in the voluntary certification program or a manufacturer of equipment containing such engines?*

The facility is not an engine manufacturer and therefore these requirements do not apply.

§60.4242 *What other requirements must I meet if I am a manufacturer of stationary SI internal combustion engines or equipment containing stationary SI internal combustion engines or a manufacturer of equipment containing such engines?*

The facility is not an engine manufacturer and therefore these requirements do not apply.

§60.4243 *What are my compliance requirements if I am an owner or operator of a stationary SI internal combustion engine?*

(b) If you are an owner or operator of a stationary SI internal combustion engine and must comply with the emission standards specified in §60.4233(d) or (e), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) and (2) of this section.

(1) Purchasing an engine certified according to procedures specified in this subpart, for the same model year and demonstrating compliance according to one of the methods specified in paragraph (a) of this section.

(2) Purchasing a non-certified engine and demonstrating compliance with the emission standards specified in §60.4233(d) or (e) and according to the requirements specified in §60.4244, as applicable, and according to paragraphs (b)(2)(i) and (ii) of this section.

(ii) If you are an owner or operator of a stationary SI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.

(e) Owners and operators of stationary SI natural gas fired engines may operate their engines using propane for a maximum of 100 hours per year as an alternative fuel solely during emergency operations, but must keep records of such use. If propane is used for more than 100 hours per year in an engine that is not certified to the emission standards when using propane, the owners and operators are required to conduct a performance test to demonstrate compliance with the emission standards of §60.4233.

(g) It is expected that air-to-fuel ratio controllers will be used with the operation of three-way catalysts/non-selective catalytic reduction. The AFR controller must be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times.

The permittee shall keep a maintenance plan and records for minimizing emissions. Performance tests will be required according to the schedule stated above.

§60.4244 *What test methods and other procedures must I use if I am an owner or operator of a stationary SI internal combustion engine?*

Owners and operators of stationary SI ICE who conduct performance tests must follow the procedures in paragraphs (a) through (f) of this section.

(a) Each performance test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and according to the requirements in §60.8 and under the specific conditions that are specified by Table 2 to this subpart.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §60.8(c). If your stationary SI internal combustion engine is non-operational, you do not need to startup the engine solely to conduct a performance test; however, you must conduct the performance test immediately upon startup of the engine.

(c) You must conduct three separate test runs for each performance test required in this section, as specified in §60.8(f). Each test run must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and last at least 1 hour.

(d) To determine compliance with the NO_x mass per unit output emission limitation, convert the concentration of NO_x in the engine exhaust using Equation 1 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{HP-hr} \qquad \text{(Eq. 1)}$$

Where:

ER = Emission rate of NO_x in g/HP-hr.

C_d = Measured NO_x concentration in parts per million by volume (ppmv).

1.912×10^{-3} = Conversion constant for ppm NO_x to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, horsepower-hour (HP-hr).

(e) To determine compliance with the CO mass per unit output emission limitation, convert the concentration of CO in the engine exhaust using Equation 2 of this section:

$$ER = \frac{C_d \times 1.164 \times 10^{-3} \times Q \times T}{HP - hr} \quad \text{(Eq. 2)}$$

Where:

ER = Emission rate of CO in g/HP-hr.

C_d = Measured CO concentration in ppmv.

1.164×10^{-3} = Conversion constant for ppm CO to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

(f) For purposes of this subpart, when calculating emissions of VOC, emissions of formaldehyde should not be included. To determine compliance with the VOC mass per unit output emission limitation, convert the concentration of VOC in the engine exhaust using Equation 3 of this section:

$$ER = \frac{C_d \times 1.833 \times 10^{-3} \times Q \times T}{HP - hr} \quad \text{(Eq. 3)}$$

Where:

ER = Emission rate of VOC in g/HP-hr.

C_d = VOC concentration measured as propane in ppmv.

1.833×10^{-3} = Conversion constant for ppm VOC measured as propane, to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

(g) If the owner/operator chooses to measure VOC emissions using either Method 18 of 40 CFR part 60, appendix A, or Method 320 of 40 CFR part 63, appendix A, then it has the option of correcting the measured VOC emissions to account for the potential differences in measured values between these methods and Method 25A. The results from Method 18 and Method 320 can be corrected for response factor differences using Equations 4 and 5 of this section. The corrected VOC concentration can then be placed on a propane basis using Equation 6 of this section.

$$RF_i = \frac{C_{Mi}}{C_{Ai}} \quad \text{(Eq. 4)}$$

Where:

RF_i = Response factor of compound i when measured with EPA Method 25A.

C_{Mi} = Measured concentration of compound i in ppmv as carbon.

C_{Ai} = True concentration of compound i in ppmv as carbon.

$$C_{icorr} = RF_i \times C_{imeas} \quad \text{(Eq. 5)}$$

Where:

C_{icorr} = Concentration of compound i corrected to the value that would have been measured by EPA Method 25A, ppmv as carbon.

C_{imeas} = Concentration of compound i measured by EPA Method 320, ppmv as carbon.

$$C_{Peq} = 0.6098 \times C_{icorr} \qquad \text{(Eq. 6)}$$

Where:

C_{Peq} = Concentration of compound i in mg of propane equivalent per DSCM.

The permittee shall conduct performance tests according to the procedures outlined above.

§60.4245 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine?

Owners or operators of stationary SI ICE must meet the following notification, reporting and recordkeeping requirements.

(a) Owners and operators of all stationary SI ICE must keep records of the information in paragraphs (a)(1) through (4) of this section.

(1) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(2) Maintenance conducted on the engine.

(4) If the stationary SI internal combustion engine is not a certified engine or is a certified engine operating in a non-certified manner and subject to §60.4243(a)(2), documentation that the engine meets the emission standards.

(c) Owners and operators of stationary SI ICE greater than or equal to 500 HP that have not been certified by an engine manufacturer to meet the emission standards in §60.4231 must submit an initial notification as required in §60.7(a)(1). The notification must include the information in paragraphs (c)(1) through (5) of this section.

(1) Name and address of the owner or operator;

(2) The address of the affected source;

(3) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(4) Emission control equipment; and

(5) Fuel used.

(d) Owners and operators of stationary SI ICE that are subject to performance testing must submit a copy of each performance test as conducted in §60.4244 within 60 days after the test has been completed.

If the applicable IC engine is not certified by the manufacturer, the permittee shall comply with the requirements above.

NESHAP Applicability (40 CFR 61)

The facility is not subject to any NESHAP requirements in 40 CFR 61.

MACT Applicability (40 CFR 63)

The facility will operate one compressor engine that may be subject to the requirements of 40 CFR 63 Subpart ZZZZ depending on date of manufacture. The compressor IC engine is a 610 bhp natural gas-fired engine. Below is a breakdown of Subpart ZZZZ. DEQ is delegated this Subpart.

40 CFR 63, Subpart ZZZZ................................National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

§63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

The facility will operate one non-emergency engine. In addition, the facility is an area source for HAPs as they are below the major source threshold of 10 T/yr for any one federally regulated HAP and 25 T/yr for all HAPs combined.

§63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) Affected source. An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) Existing stationary RICE.

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) New stationary RICE. (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(c) Stationary RICE subject to Regulations under 40 CFR Part 60. An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

The IC engine to be located at the facility will be considered existing if they commenced construction of the engine before June 12, 2006. If the engine installed is considered new they will be subject to the regulations of 40 CFR Part 60 Subpart JJJJ.

§63.6595 When do I have to comply with this subpart?

(a) Affected sources. (1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations, operating limitations and other requirements no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than October 19, 2013.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in §63.6645 and in 40 CFR part 63, subpart A.

The IC engine must be in compliance with the Subpart no later than October 19, 2013 or upon installation.

§63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

The applicable IC engine is not operating at a major source for HAP emissions. Therefore there are no applicable emission and operating limitations under this section.

§63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

The applicable IC engine is not operating at a major source for HAP emissions and the engine is not 4-stroke lean burn spark ignition between 250 and 500 bhp. Therefore there are no applicable emission and operating limitations under this section.

§63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

The applicable IC engine is not operating at a major source for HAP emissions. Therefore there are no applicable emission and operating limitations under this section.

§63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart that apply to you.

Table 2b does not apply to the IC engine at the facility. The engine is not CI stationary RICE and is not located at a major source of HAP emissions. Table 2d identifies those limitations required by area sources to comply with the Subpart. The specifics of Table 2d require that the permittee install NSCR (non-selective catalytic reduction) to reduce HAP emissions from the stationary RICE.

§63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

The applicable IC engine is not a stationary CI RICE. Therefore there are no applicable emission and operating limitations under this section.

§63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

When operating the IC engine, it must be operated in a manner that is consistent with reducing emissions and compliance with appropriate limitations applies at all times.

§63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

The applicable IC engine is not operating at a major source for HAP emissions. Therefore there are no applicable emission and operating limitations under this section.

§63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

The applicable IC engine is not operating at a major source for HAP emissions. Therefore there are no applicable emission and operating limitations under this section.

§63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

Table 5 requires the applicable IC engine to comply with the requirement to install NSCR using an oxidation catalyst. Initial compliance has been demonstrated if the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more. Initial compliance has also been demonstrated if a CPMS has been installed to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b), or if equipment has been installed to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.

§63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

The applicable IC engine is not subject to subsequent performance tests as specified in Table 3.

§63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section.

(1) Non-emergency 4SRB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(2) New non-emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP located at a major source of HAP emissions.

(3) New non-emergency 2SLB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(4) New non-emergency CI stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour, unless otherwise specified in this subpart.

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad \text{(Eq. 1)}$$

Where:

C_i = concentration of carbon monoxide (CO), total hydrocarbons (THC), or formaldehyde at the control device inlet,

C_o = concentration of CO, THC, or formaldehyde at the control device outlet, and

R = percent reduction of CO, THC, or formaldehyde emissions.

(2) You must normalize the CO, THC, or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2 concentration is measured in lieu of oxygen concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209\ F_d}{F_c} \quad \text{(Eq. 2)}$$

Where:

F_o = Fuel factor based on the ratio of oxygen volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu)

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO2} = \frac{5.9}{F_o} \quad \text{(Eq. 3)}$$

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2—15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO2}}{\%CO_2} \quad \text{(Eq. 4)}$$

Where:

C_{adj} = Calculated concentration of CO, THC, or formaldehyde adjusted to 15 percent O_2.

C_d = Measured concentration of CO, THC, or formaldehyde, uncorrected.

X_{CO2} = CO_2 correction factor, percent.

$\%CO_2$ = Measured CO_2 concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (e.g., operator adjustment, automatic controller adjustment, etc.) or unintentionally (e.g., wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

The applicable IC engine is not subject to the subsequent performance tests criteria listed above.

§63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either O_2 or CO_2 according to the requirements in paragraphs (a)(1) through (4) of this section. If you are meeting a requirement to reduce CO emissions, the CEMS must be installed at both the inlet and outlet of the control device. If you are meeting a requirement to limit the concentration of CO, the CEMS must be installed at the outlet of the control device.

A CEMS is not required and will not be installed on the applicable IC engine. Therefore this requirement is not applicable.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (6) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

A CPMS is not required and will not be installed on the applicable IC engine. Therefore this requirement is not applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

The applicable IC engine will not use landfill or digester gas as fuel. Therefore there are no applicable requirements under this section.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

The applicable IC engine is not operating at a major source for HAP emissions. Therefore there are no applicable requirements under this section.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start stationary RICE located at an area source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

The applicable IC engine does not fall into one of the ten categories listed above. Therefore there are no applicable requirements under this section.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

The applicable IC engine is not emergency stationary RICE. Therefore there are no applicable requirements under this section.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska that meet either §63.6603(b)(1) or §63.6603(b)(2) do not have to meet the requirements of this paragraph (g). Existing CI engines located on offshore vessels that meet §63.6603(c) do not have to meet the requirements of this paragraph (g).

The applicable IC engine is not a CI engine. Therefore there are no applicable requirements under this section.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

Idle startup time may not exceed 30 minutes for the applicable IC engine.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

The applicable IC engine is not a CI engine. Therefore there are no applicable requirements under this section.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

The applicable IC engine is not subject to the items in Table 2d and therefore there are no applicable requirements under this section.

§63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.6645.

(d) Non-emergency 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more can demonstrate initial compliance with the formaldehyde emission limit by testing for THC instead of formaldehyde. The testing must be conducted according to the requirements in Table 4 of this subpart. The average reduction of emissions of THC determined from the performance test must be equal to or greater than 30 percent.

(e) The initial compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least three test runs.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

The permittee is subject to the requirements of 40 CFR 63.6630(e) as outlined above.

§63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

The permittee must monitor and collect data continuously for the applicable IC engine except in instances included in §63.6635 (b).

§63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least one test run.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP

emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

The applicable IC engine will demonstrate compliance through the annual compliance test according to §63.6640(c) above.

§63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(2) An existing stationary RICE located at an area source of HAP emissions.

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in §63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to §63.10(d)(2).

The facility must comply with the notification requirements in §§63.7(b) and (c) and compliance demonstrations.

§63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in §63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out-of-control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

The reports that must be maintained in accordance with the Subpart are stated in this section. The permittee is required to submit semi-annual Compliance reports (see Table 7 of the subpart for further details).

§63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in §63.10(b)(2)(xiv).

(2) Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment.

(3) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

The permittee is required to maintain records of all required notifications, each malfunction, all performance tests and results, any required maintenance, and any corrective action that was taken.

§63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1).

All records must be kept by the permittee for a minimum of five (5) years for each record.

Permit Conditions Review

This section describes the permit conditions for this initial permit.

Permit Condition 1.1 establishes the permit to construct scope.

Permit Condition 2.1 provides a process description of the operations at the facility.

Permit Condition 2.2 provides a description of the control devices used at the facility.

Permit Condition 2.3 establishes an emission limit for new sources from any fuel burning equipment.

Permit Condition 2.4 establishes a 20% opacity limit to any stack, vent, or functionally equivalent opening associated with the facility.

Permit Condition 2.5 establishes the flare particulate matter emission limit for the flare.

Permit Condition 2.6 establishes fuel use restrictions for the equipment at the facility. These fuel use restrictions were based on the fuel proposed by the Applicant.

Permit Condition 2.7 requires that a pilot flame be present at the flare.

Permit Condition 2.8 establishes that fugitive emissions at the facility be reasonably controlled.

Permit Condition 2.9 establishes that the permittee conduct inspections of visible emissions to demonstrate compliance with the opacity limit permit condition.

Permit Condition 2.10 establishes that the permittee conduct inspections of sources of fugitive emissions to demonstrate compliance with the fugitive emissions permit condition.

Permit Conditions 2.11 through 2.149 establish the requirements the facility must meet as required by 40 CFR 60, Subpart OOOO.

Permit Condition 2.150 provides the general provisions from 40 CFR 60 Subpart A.

Permit Condition 2.151 provides for the incorporation of any NSPS and NESHAP standards into the permit.

Permit Condition 3.1 provides a process description of the engine used at the facility.

Permit Condition 3.2 provides a description of the control device used on the engine at this facility.

Permit Condition 3.3 establishes a 20% opacity limit for the engine exhaust stack.

Permit Condition 3.4 establishes fuel use restrictions for the engine. These fuel use restriction was based on the fuel proposed by the Applicant to be combusted in the engine.

Permit Condition 3.5 establishes that the permittee conduct inspections of visible emissions to demonstrate compliance with the opacity limit permit condition.

Permit Conditions 3.6 through 3.27 establish the requirements the facility must meet as required by 40 CFR 63 Subpart ZZZZ. These permit conditions outline the requirements for the engine.

Permit Conditions 3.28 through 3.42 establish the requirements the facility must meet as required by 40 CFR 60 Subpart JJJJ. These permit conditions outline the requirements for the engine.

Permit Condition 4.1 requires that the permittee comply with all of the permit terms and conditions pursuant to Idaho Code §39-101.

Permit Condition 4.2 requires that the permittee maintain and operate all treatment and control facilities at the facility in accordance with IDAPA 58.01.01.211.

Permit Condition 4.3 specifies that no permit condition is intended to relieve or exempt the permittee from compliance with applicable state and federal requirements, in accordance with IDAPA 58.01.01.212.01.

Permit Condition 4.4 requires that the permittee allow DEQ inspection and entry pursuant to Idaho Code §39-108.

Permit Condition 4.5 specifies that the permit expires if construction has not begun within two years of permit issuance or if construction has been suspended for a year in accordance with IDAPA 58.01.01.211.02.

Permit Condition 4.6 requires that the permittee notify DEQ of the dates of construction and operation, in accordance with IDAPA 58.01.01.211.03.

Permit Condition 4.7 requires that the permittee notify DEQ at least 15 days prior to any performance test to provide DEQ the option to have an observer present, in accordance with IDAPA 58.01.01.157.03.

Permit Condition 4.8 requires that any performance testing be conducted in accordance with the procedures of IDAPA 58.01.01.157, and encourages the permittee to submit a protocol to DEQ for approval prior to testing.

Permit Condition 4.9 requires that the permittee report any performance test results to DEQ within 30 days of completion, in accordance with IDAPA 58.01.01.157.04-05.

Permit Condition 4.10 requires that the permittee maintain sufficient records to ensure compliance with permit conditions, in accordance with IDAPA 58.01.01.211.

Permit Condition 4.11 requires that the permittee follow the procedures required for excess emissions events, in accordance with IDAPA 58.01.01.130-136.

Permit Condition 4.12 requires that a responsible official certify all documents submitted to DEQ, in accordance with IDAPA 58.01.01.123.

Permit Condition 4.13 requires that no person make false statements, representations, or certifications, in accordance with IDAPA 58.01.01.125.

Permit Condition 4.14 requires that no person render inaccurate any required monitoring device or method, in accordance with IDAPA 58.01.01.126.

Permit Condition 4.15 specifies that this permit to construct is transferable, in accordance with the procedures of IDAPA 58.01.01.209.06.

Permit Condition 4.16 specifies that permit conditions are severable, in accordance with IDAPA 58.01.01.211.

PUBLIC REVIEW

Public Comment Opportunity

An opportunity for public comment period on the application was provided in accordance with IDAPA 58.01.01.209.01.c or IDAPA 58.01.01.404.01.c. During this time, there were no comments on the application and there was a request for a public comment period on DEQ's proposed action. Refer to the chronology for public comment opportunity dates.

Public Comment Period

A public comment period was made available to the public in accordance with IDAPA 58.01.01.209.01.c. During this time, comments were submitted in response to DEQ's proposed action. Refer to the chronology for public comment period dates.

A response to public comments document has been crafted by DEQ based on comments submitted during the public comment period. That document is part of the final permit package for this permitting action.

APPENDIX A – EMISSIONS INVENTORIES

Alta Mesa Services
ML Investments 1-3 Well Site Facility Emission Summary

Source Description		Well Head Heater	Line Heater	Heater Treater	Engine	Water Tanks	Oil Tanks	Loading	Flare	Summary of Emissions
Source Information		0.05 MMbtu/hr	0.5 MMbtu/hr	1.0 MMbtu/hr	Caterpillar G398TA Type Engine - 610 hp	4 Tanks at 80 BWPD (No Control)	10 Tanks at 500 BOPD (95% Control)	500 BOPD (98% Control)	Flare at 100 MSCFD	
EPNs		WHHTR1	LNHTR1	HTRTR1	ENG1	WTRTNK1-4	OILTNK1-10	LOAD1	FLR1	
VOC_{total}	lb/hr	0.0002	0.0022	0.0045	0.6718	0.1448	4.3825	0.6008	0.4227	**6.2295**
	TPY	0.0010	0.0098	0.0196	2.9425	0.6345	19.1960	0.4775	1.8513	**25.1322**
NOx	lb/hr	0.0041	0.0407	0.0813	1.3436				0.3537	**1.8234**
	TPY	0.0178	0.1780	0.3561	5.8850				1.5493	**7.9863**
CO	lb/hr	0.0034	0.0341	0.0683	2.6872				1.6126	**4.4057**
	TPY	0.0150	0.1496	0.2991	11.7700				7.0631	**19.2968**
PM_{10}	lb/hr	0.0003	0.0031	0.0062	0.0924				0.0052	**0.1072**
	TPY	0.0014	0.0135	0.0271	0.4047				0.0228	**0.4694**
$PM_{2.5}$	lb/hr	0.0002	0.0023	0.0046	0.0924				0.0052	**0.1048**
	TPY	0.0010	0.0101	0.0203	0.4047				0.0228	**0.4590**
SO_2	lb/hr	0.00002	0.0002	0.0005	0.0028				0.0052	**0.0088**
	TPY	0.0001	0.0011	0.0021	0.0123				0.0228	**0.0384**
Formaldehyde	lb/hr	3.05E-07	3.05E-06	6.10E-06	0.2514					**0.2514**
	TPY	1.34E-06	1.34E-05	2.67E-05	1.1009					**1.1010**
Benzene	lb/hr	8.54E-08	8.54E-07	1.71E-06	0.0075	0.0001	0.0030	0.0002	0.00016	**0.0110**
	TPY	3.74E-07	3.74E-06	7.48E-06	0.0329	0.0005	0.0130	0.0002	0.0007	**0.0473**
Toluene	lb/hr	1.38E-07	1.38E-06	2.76E-06	0.0027	0.0001	0.0035	0.0002	0.0002	**0.0067**
	TPY	6.05E-07	6.05E-06	1.21E-05	0.0116	0.0005	0.0145	0.0002	0.0007	**0.0276**
Ethylbenzene	lb/hr				0.0002	0.0000	0.0010	0.0001	0.0000	**0.0013**
	TPY				0.0008	0.0001	0.0035	0.0000	0.0002	**0.0047**
Xylene	lb/hr				0.0009	0.0001	0.0025	0.0002	0.0001	**0.0038**
	TPY				0.0041	0.0004	0.0115	0.0001	0.0005	**0.0166**

FUGITIVE EMISSION CALCULATIONS

EPN: FUG1

Component Type	Gas Component Count	Heavy Oil Component Count	Light Oil Component Count	Water/Light Oil Component Count
Valves	150	25	75	25
Pumps	0	4	0	1
Flanges / Connectors	150	50	100	25
Compressors	1	0	0	0
Relief Lines	3	0	2	2
Open-ended Lines	2	0	0	1
Other	0	0	5	5
Process Drains	5	5	5	5

Component Type	Gas lb/hr per component	Heavy Oil lb/hr per component	Light Oil lb/hr per component	Water/Light Oil lb/hr per component	Gas Emission Rate (lbs/hr)	Heavy Oil Emssion Rate (lbs/hr)	Light Oil Emission Rate (lbs/hr)	Water/Light Oil Emission Rate (lbs/hr)	Control Efficiency %	Control Efficiency %	Total Emissions lbs/hr	Total Emissions tn/yr
Valves	0.0092	0.00002	0.0055	0.0002	0.3152	0.0005	0.4125	0.0054	0%		0.7336	3.2132
Pumps	0.0053	0.0011	0.0287	0.0001	0.0000	0.0045	0.0000	0.0001	0%		0.0046	0.0200
Flanges / Connectors	0.0009	0.000001	0.0002	0.0000	0.0295	0.000043	0.0243	0.0002	0%	0%	0.0540	0.2364
Compressors	0.0194	0.0001	0.0165	0.0309	0.0044	0.000000	0.0000	0.0000	0%		0.0044	0.0194
Relief Lines	0.0194	0.0001	0.0165	0.0309	0.0133	0.000000	0.0330	0.0618	0%		0.1081	0.4735
Open-ended Lines	0.0044	0.0003	0.0031	0.0006	0.0020	0.000000	0.0000	0.0006	0%		0.0026	0.0115
Other	0.0194	0.0001	0.0165	0.0309	0.0000	0.000000	0.0825	0.1545	0%		0.2370	1.0381
Process Drains	0.0194	0.0001	0.0165	0.0309	0.0222	0.0003	0.0825	0.1545	0%		0.2595	1.1366
Totals											**1.4038**	**6.1486**

Component	Mole Wt	Mole%	lb/mol Mix	Wt%	Percentage	EMISSIONS lbs/hr	EMISSIONS TPY
Methane	16.043	84.8561	13.613	66.981	67.0%	VOC Speciation	
Nitrogen	28.013	0.4883	0.137	0.673	0.7%		
Carbon Dioxide	44.01	0.1433	0.063	0.310	0.3%		
Ethane	30.07	6.2131	1.868	9.192	9.2%		
Hydrogen Sulfide	34.08	0.0000	0.000	0.000	0.0%		
Propane	44.097	4.0209	1.773	8.724	8.7%	0.1225	0.5364
Iso-butane	58.124	0.9324	0.542	2.666	2.7%	0.0374	0.1640
N-Butane	58.124	1.5751	0.916	4.505	4.5%	0.0632	0.2770
Iso-Pentane	72.151	0.5374	0.388	1.908	1.9%	0.0268	0.1173
N-Pentane	72.151	0.5433	0.392	1.929	1.9%	0.0271	0.1186
N-Hexane	86.07	0.2249	0.194	0.952	1.0%	0.0134	0.0586
Cyclohexane	84.16	0.0342	0.029	0.142	0.1%	0.0020	0.0087
Heptanes	100.21	0.1201	0.120	0.592	0.6%	0.0083	0.0364
Methylcyclohexane	96.17	0.0266	0.026	0.126	0.1%	0.0018	0.0077
224-Trimethylpentane	114.22	0.0068	0.008	0.038	0.0%	0.0005	0.0023
Benzene	78.11	0.0035	0.003	0.013	0.0%	0.0002	0.0008
Toluene	92.14	0.0021	0.002	0.010	0.0%	0.0001	0.0006
Ethylbenzene	106.17	0.0003	0.000	0.002	0.0%	0.0000	0.0001
Xylenes	106.16	0.0005	0.001	0.003	0.0%	0.0000	0.0002
Hexanes +	92.12	0.2421	0.223	1.097	1.1%	0.0154	0.0675
C8 Heavies	96.09	0.0290	0.028	0.137	0.137%	0.0019	0.0084
		8.30	20.324	100.000	100%		
		100.0000	VOC 22.843		22.8%		

Notes:
Gas Analysis - Questar Applied Technology, 1/3/2013, ML Investments 1-10

EPN: WHHTR1

Name/Type	Well Head Heater
Heater Rating (MMBtu/hr)	0.05
Operating Hours	8760
Fuel Heat Value (Btu/SCF)	1230

Pollutant	Emission Factor (lb/MMCF)	Reference	lb/hr	tpy
VOC	5.5	AP-42	0.0002	0.0010
NOx	100	AP-42	0.0041	0.0178
CO	84	AP-42	0.0034	0.0150
PM_{10}	7.6	AP-42	0.0003	0.0014
$PM_{2.5}$	5.7	AP-42	0.0002	0.0010
SO_2	0.6	AP-42	0.0000	0.0001
HCHO	0.0075	AP-42	0.000000	0.000001
Benzene	0.0021	AP-42	0.000000	0.000000
Toluene	0.0034	AP-42	0.000000	0.000001

Calculation Notes:
Natural Gas Combustion Factor Data based on AP-42, Table 1.4-1 - 1.4.3.

EPN:	LNHTR1
Name/Type	Line Heater
Heater Rating (MMBtu/hr)	0.5
Operating Hours	8760
Fuel Heat Value (Btu/SCF)	1230

Pollutant	Emission Factor (lb/MMCF)	Reference	lb/hr	tpy
VOC	5.5	AP-42	0.0022	0.0098
NOx	100	AP-42	0.0407	0.1780
CO	84	AP-42	0.0341	0.1496
PM_{10}	7.6	AP-42	0.0031	0.0135
$PM_{2.5}$	5.7	AP-42	0.0023	0.0101
SO_2	0.6	AP-42	0.0002	0.0011
HCHO	0.0075	AP-42	0.000003	0.000013
Benzene	0.0021	AP-42	0.000001	0.000004
Toluene	0.0034	AP-42	0.000001	0.000006

Calculation Notes:
Natural Gas Combustion Factor Data based on AP-42, Table 1.4-1 - 1.4.3.

EPN: HTRTR1

Name/Type	Heater Treater
Heater Rating (MMBtu/hr)	1
Operating Hours	8760
Fuel Heat Value (Btu/SCF)	1230

Pollutant	Emission Factor (lb/MMCF)	Reference	lb/hr	tpy
VOC	5.5	AP-42	0.0045	0.0196
NOx	100	AP-42	0.0813	0.3561
CO	84	AP-42	0.0683	0.2991
PM_{10}	7.6	AP-42	0.0062	0.0271
$PM_{2.5}$	5.7	AP-42	0.0046	0.0203
SO_2	0.6	AP-42	0.0005	0.0021
HCHO	0.0075	AP-42	0.000006	0.000027
Benzene	0.0021	AP-42	0.000002	0.000007
Toluene	0.0034	AP-42	0.000003	0.000012

Calculation Notes:
Natural Gas Combustion Factor Data based on AP-42, Table 1.4-1 - 1.4.3.

EPN: ENG1
Caterpillar G398 TA HCR (Type Engine)
Engine SN:
Man. Date:
Manufacturer's Rated Horsepower 610 hp
Fuel Input 0.007804 MMBtu/hp-hr
Operating Schedule: 8760 hours annually

			FACTORS			EMISSIONS	
				lean	rich		
Pollutant	Reference	Control Efficiency	grams/bhp-hr	lb/MMBtu	lb/MMBtu	lbs/hr	TPY
NOx	Manuf. Engine Data	----	1.00			1.3436	5.8850
CO	Manuf. Engine Data	----	2.00			2.6872	11.7700
VOC_{total}	Manuf. Engine Data	----	0.50			0.6718	2.9425
SO2	AP-42	----		0.00059	0.00059	0.0028	0.0123
PM10	AP-42	----		0.00999	0.01941	0.0924	0.4047
PM2.5	AP-42	----		0.00999	0.01941	0.0924	0.4047
HCHO	AP-42	----		0.05280	0.02050	0.2514	1.1009
Benzene	AP-42	----		0.00044	0.00158	0.0075	0.0329
Toluene	AP-42	----		0.00041	0.00056	0.0027	0.0116
Ethylbenzene	AP-42	----		0.00004	0.00002	0.0002	0.0008
Xylene	AP-42	----		0.00018	0.00020	0.0009	0.0041
Acetaldehyde	AP-42	----		0.00836	0.00279	0.0398	0.1743
Acrolein	AP-42	----		0.00514	0.00263	0.0245	0.1072
1,1-dichloroethane	AP-42	----		0.00002	0.00001	0.0001	0.0005
1,2-dichloroethane	AP-42	----		0.00002	0.00001	0.0001	0.0005
1,1,2-Trichloroethane	AP-42	----		0.00003	0.00002	0.0002	0.0007
1,1,2,2-Tetrachloroethane	AP-42	----		0.00004	0.00003	0.0002	0.0008
1,2-dichloropropane	AP-42	----		0.00003	0.00001	0.0001	0.0006
1,3-butadiene	AP-42	----		0.00027	0.00066	0.0032	0.0138
1,3-dichloropropene	AP-42	----		0.00003	0.00001	0.0001	0.0006
2,2,4-Trimethylpentane	AP-42	----		0.00025		0.0012	0.0052
Benzo(b)fluoranthene	AP-42	----		0.00000		0.0000	0.0000
Benzo(e)pyrene	AP-42	----		0.00000		0.0000	0.0000
Biphenyl	AP-42	----		0.00021		0.0010	0.0044
Carbon Tetrachloride	AP-42	----		0.00004	0.00002	0.0002	0.0008
Chlorobenzene	AP-42	----		0.00003	0.00001	0.0001	0.0006
Chloroethane	AP-42	----		0.00000		0.0000	0.0000
Chloroform	AP-42	----		0.00003	0.00001	0.0001	0.0006
Chrysene	AP-42	----		0.00000		0.0000	0.0000
Cyclopentane	AP-42	----		0.00023		0.0011	0.0047
Ethylene Dibromide	AP-42	----		0.00004	0.00002	0.0002	0.0009
Methanol	AP-42	----		0.00250	0.00306	0.0146	0.0638
Methylcyclohexane	AP-42	----		0.00123		0.0059	0.0256
Methylene Chloride	AP-42	----		0.00002	0.00004	0.0002	0.0009
n-Hexane	AP-42	----		0.00111		0.0053	0.0231
n-Nonane	AP-42	----		0.00011		0.0005	0.0023
n-Octane	AP-42	----		0.00035		0.0017	0.0073
n-Pentane	AP-42	----		0.00260		0.0124	0.0542
Naphthalene	AP-42	----		0.00007	0.00010	0.0005	0.0020
PAH	AP-42	----		0.00003	0.00014	0.0007	0.0029
Phenol	AP-42	----		0.00002		0.0001	0.0005
Vinyl Chloride	AP-42	----		0.00001	0.00001	0.0001	0.0003

Example Calculations:
NOx: ((1.0 grams/bhp-hr)(610 bhp))(1/454) = 1.3436 lbs/hr
NOx: (1.3436 lbs/hr)(8760 hrs/yr)/2000 = 5.8850 TPY

Calculation Notes:
Engine Data based on AP-42 Section 3.2, Manufacturer Engine Data Sheets

EPN: WTRTNK1-4

Water Tank E&P Calculations: ML Investment 1-10,2-10 (Low Pressure Oil)
Operating Schedule: 8760 hours annually

Control Efficiency	0%
Throughput (BWPD)	80
Tank Count	4

Water Tank E&P Calculations					
TANKS		EMISSIONS		EMISSIONS-CONTROLLED	
Size	BWPD	lb/hr ER	Annual (TPY)	lb/hr ER	Annual (TPY)
400 bbl	20	3.621	15.862	0.0362	0.1586
		Total VOCs		0.1448	0.6345

*Emissions calculated using 1% of emissions represented from condensate

	Reduction %	1%	Total Emissions	
Emissions Speciation	lb/hr ER	Annual (TPY)	lb/hr ER	Annual (TPY)
Benzene	0.003	0.012	0.0001	0.0005
Toluene	0.003	0.013	0.0001	0.0005
Ethybenzene	0.001	0.003	0.0000	0.0001
Xylenes	0.002	0.010	0.0001	0.0004

```
*************************************************************************************
*     Project Setup Information                                                     *
*************************************************************************************
Project File                : C:\Documents and Settings\ECS\My Documents\My Notebook\ECS Clients\ECS CLIENT FILES\
Flowsheet Selection         : Oil Tank with Separator
Calculation Method          : AP42
Control Efficiency          : 100.0%
Known Separator Stream      : Low Pressure Oil
Entering Air Composition    : No

Filed Name                  : ML Investment 1-10, 2-10
Date                        : 2014.06.13

*************************************************************************************
*     Data Input                                                                    *
*************************************************************************************

Separator Pressure          : 250.00[psig]
Separator Temperature       : 102.00[F]
Ambient Pressure            : 14.70[psia]
Ambient Temperature         : 60.00[F]
C10+ SG                     : 0.7460
C10+ MW                     : 160.99

-- Low Pressure Oil -----------------------------------------------------------------
   No.     Component              mol %
   1       H2S                    0.0000
   2       O2                     0.0000
   3       CO2                    0.0000
   4       N2                     0.0000
   5       C1                     4.9554
   6       C2                     1.7233
   7       C3                     3.3193
   8       i-C4                   1.6162
   9       n-C4                   4.0632
   10      i-C5                   2.9444
   11      n-C5                   4.1376
   12      C6                     4.5705
   13      C7                    19.8607
   14      C8                    15.0077
   15      C9                    10.4805
   16      C10+                  18.4132
   17      Benzene                0.1247
   18      Toluene                0.4338
   19      E-Benzene              0.2831
   20      Xylenes                1.0386
   21      n-C6                   6.3697
   22      224Trimethylp          0.6584

-- Sales Oil ------------------------------------------------------------------------
Production Rate             : 20[bbl/day]
Days of Annual Operation    : 365 [days/year]
API Gravity                 : 71.89
Reid Vapor Pressure         : 273.523[psia]
Bulk Temperature            : 102.00[F]

-- Tank and Shell Data --------------------------------------------------------------
Diameter                    : 12.00[ft]
Shell Height                : 20.00[ft]
Cone Roof Slope             : 0.06
Average Liquid Height       : 10.00[ft]
Vent Pressure Range         : 0.06[psi]
Solar Absorbance            : 0.68

-- Meteorological Data --------------------------------------------------------------
```

City	:	Denver, CO
Ambient Pressure	:	14.70[psia]
Ambient Temperature	:	60.00[F]
Min Ambient Temperature	:	36.20[F]
Max Ambient Temperature	:	64.30[F]
Total Solar Insolation	:	1568.00[Btu/ft^2*day]

****
*   Calculation Results   *
****

-- Emission Summary --

Item	Uncontrolled [ton/yr]	Uncontrolled [lb/hr]
Total HAPs	0.760	0.174
Total HC	25.432	5.806
VOCs, C2+	19.022	4.343
VOCs, C3+	15.862	3.621

Uncontrolled Recovery Info.

Vapor	1.6200	[MSCFD]
HC Vapor	1.6200	[MSCFD]
GOR	81.00	[SCF/bbl]

-- Emission Composition --

No	Component	Uncontrolled [ton/yr]	Uncontrolled [lb/hr]
1	H2S	0.000	0.000
2	O2	0.000	0.000
3	CO2	0.000	0.000
4	N2	0.000	0.000
5	C1	6.409	1.463
6	C2	3.160	0.721
7	C3	5.233	1.195
8	i-C4	1.798	0.411
9	n-C4	3.392	0.774
10	i-C5	1.298	0.296
11	n-C5	1.367	0.312
12	C6	0.617	0.141
13	C7	1.027	0.234
14	C8	0.278	0.063
15	C9	0.074	0.017
16	C10+	0.021	0.005
17	Benzene	0.012	0.003
18	Toluene	0.013	0.003
19	E-Benzene	0.003	0.001
20	Xylenes	0.010	0.002
21	n-C6	0.688	0.157
22	224Trimethylp	0.032	0.007
	Total	25.432	5.806

-- Stream Data ---

No.	Component	MW	LP Oil mol %	Flash Oil mol %	Sale Oil mol %	Flash Gas mol %	W&S Gas mol %	Total Emissions mol %
1	H2S	34.80	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	O2	32.00	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	CO2	44.01	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	N2	28.01	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
5	C1	16.04	4.9554	0.3322	0.0000	53.8958	0.0001	51.2626
6	C2	30.07	1.7233	0.5469	0.0000	14.1768	0.0000	13.4842
7	C3	44.10	3.3193	2.2146	0.8513	15.0133	19.4086	15.2280
8	i-C4	58.12	1.6162	1.4297	1.0604	3.5901	11.3572	3.9696
9	n-C4	58.12	4.0632	3.8252	3.1613	6.5826	25.1054	7.4876
10	i-C5	72.15	2.9444	3.0419	2.9465	1.9119	10.0279	2.3085
11	n-C5	72.15	4.1376	4.3419	4.3145	1.9743	11.3092	2.4304
12	C6	86.16	4.5705	4.9334	5.1624	0.7287	5.1006	0.9423
13	C7	100.20	19.8607	21.6426	23.0911	0.9976	8.3801	1.3583

14	C8	114.23	15.0077	16.4043	17.6302	0.2232	2.2323	0.3213
15	C9	128.28	10.4805	11.4657	12.3525	0.0506	0.5941	0.0771
16	C10+	160.99	18.4132	20.1517	21.7379	0.0095	0.1492	0.0163
17	Benzene	78.11	0.1247	0.1351	0.1425	0.0145	0.1060	0.0190
18	Toluene	92.13	0.4338	0.4735	0.5072	0.0133	0.1182	0.0184
19	E-Benzene	106.17	0.2831	0.3096	0.3332	0.0027	0.0280	0.0039
20	Xylenes	106.17	1.0386	1.1359	1.2228	0.0085	0.0908	0.0125
21	n-C6	86.18	6.3697	6.8977	7.2615	0.7804	5.7715	1.0243
22	224Trimethylp	114.24	0.6584	0.7181	0.7680	0.0260	0.2208	0.0356
	MW		101.63	108.31	110.89	30.89	66.55	32.63
	Stream Mole Ratio		1.0000	0.9137	0.9093	0.0863	0.0044	0.0907
	Heating Value	[BTU/SCF]				1805.20	3695.96	1897.58
	Gas Gravity	[Gas/Air]				1.07	2.30	1.13
	Bubble Pt. @ 100F	[psia]	166.49	22.28	6.54			
	RVP @ 100F	[psia]	283.14	81.19	41.31			
	Spec. Gravity @ 100F		0.661	0.670	0.672			

EPN: OILTNK1-10

Oil Tank E&P Calculations: ML Investment 1-10,2-10(Low Pressure Oil)	
Operating Schedule: 8760 hours annually	
Control Efficiency	95%
Throughput (BOPD)	500
Tank Count	10

Oil Tank E&P Calculations					
TANKS		EMISSIONS		EMISSIONS-CONTROLLED	
Size	BOPD	lb/hr ER	Annual (TPY)	lb/hr ER	Annual (TPY)
400 bbl	50	8.765	38.392	0.4383	1.9196
		Total VOCs for all Oil Tanks		4.3825	19.1960

			EMISSIONS-CONTROLLED	
Emissions Speciation	**lbs/hr**	**Tons/yr**	lb/hr ER	Annual (TPY)
Benzene	0.006	0.026	0.0030	0.0130
Toluene	0.007	0.029	0.0035	0.0145
Ethybenzene	0.002	0.007	0.0010	0.0035
Xylenes	0.005	0.023	0.0025	0.0115

```
*****************************************************************************************
*     Project Setup Information                                                         *
*****************************************************************************************
Project File                : C:\Documents and Settings\ECS\My Documents\My Notebook\ECS Clients\ECS CLIENT FILES\
Flowsheet Selection         : Oil Tank with Separator
Calculation Method          : AP42
Control Efficiency          : 100.0%
Known Separator Stream      : Low Pressure Oil
Entering Air Composition    : No

Filed Name                  : ML Investment 1-10, 2-10
Date                        : 2014.07.07

*****************************************************************************************
*     Data Input                                                                        *
*****************************************************************************************

Separator Pressure          : 250.00[psig]
Separator Temperature       : 102.00[F]
Ambient Pressure            : 14.70[psia]
Ambient Temperature         : 60.00[F]
C10+ SG                     : 0.7460
C10+ MW                     : 160.99

-- Low Pressure Oil -----------------------------------------------------------------
   No.     Component              mol %
   1       H2S                   0.0000
   2       O2                    0.0000
   3       CO2                   0.0000
   4       N2                    0.0000
   5       C1                    4.9554
   6       C2                    1.7233
   7       C3                    3.3193
   8       i-C4                  1.6162
   9       n-C4                  4.0632
   10      i-C5                  2.9444
   11      n-C5                  4.1376
   12      C6                    4.5705
   13      C7                   19.8607
   14      C8                   15.0077
   15      C9                   10.4805
   16      C10+                 18.4132
   17      Benzene               0.1247
   18      Toluene               0.4338
   19      E-Benzene             0.2831
   20      Xylenes               1.0386
   21      n-C6                  6.3697
   22      224Trimethylp         0.6584

-- Sales Oil -----------------------------------------------------------------------
Production Rate             : 50[bbl/day]
Days of Annual Operation    : 365 [days/year]
API Gravity                 : 71.89
Reid Vapor Pressure         : 273.523[psia]
Bulk Temperature            : 102.00[F]

-- Tank and Shell Data -------------------------------------------------------------
Diameter                    : 12.00[ft]
Shell Height                : 20.00[ft]
Cone Roof Slope             : 0.06
Average Liquid Height       : 10.00[ft]
Vent Pressure Range         : 0.06[psi]
Solar Absorbance            : 0.68

-- Meteorological Data -------------------------------------------------------------
```

City	: Denver, CO
Ambient Pressure	: 14.70[psia]
Ambient Temperature	: 60.00[F]
Min Ambient Temperature	: 36.20[F]
Max Ambient Temperature	: 64.30[F]
Total Solar Insolation	: 1568.00[Btu/ft^2*day]

****
*   Calculation Results   *
****

-- Emission Summary --

Item	Uncontrolled [ton/yr]	Uncontrolled [lb/hr]
Total HAPs	1.720	0.393
Total HC	62.622	14.297
VOCs, C2+	46.465	10.608
VOCs, C3+	38.392	8.765

Uncontrolled Recovery Info.

Vapor	4.0500	[MSCFD]
HC Vapor	4.0500	[MSCFD]
GOR	81.00	[SCF/bbl]

-- Emission Composition --

No	Component	Uncontrolled [ton/yr]	Uncontrolled [lb/hr]
1	H2S	0.000	0.000
2	O2	0.000	0.000
3	CO2	0.000	0.000
4	N2	0.000	0.000
5	C1	16.157	3.689
6	C2	8.073	1.843
7	C3	13.373	3.053
8	i-C4	4.395	1.003
9	n-C4	8.174	1.866
10	i-C5	3.039	0.694
11	n-C5	3.174	0.725
12	C6	1.405	0.321
13	C7	2.299	0.525
14	C8	0.612	0.140
15	C9	0.160	0.037
16	C10+	0.043	0.010
17	Benzene	0.026	0.006
18	Toluene	0.029	0.007
19	E-Benzene	0.007	0.002
20	Xylenes	0.023	0.005
21	n-C6	1.559	0.356
22	224Trimethylp	0.071	0.016
	Total	62.619	14.297

-- Stream Data ---

No.	Component	MW	LP Oil mol %	Flash Oil mol %	Sale Oil mol %	Flash Gas mol %	W&S Gas mol %	Total Emissions mol %
1	H2S	34.80	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	O2	32.00	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	CO2	44.01	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	N2	28.01	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
5	C1	16.04	4.9554	0.3322	0.0000	53.8958	0.0001	51.6882
6	C2	30.07	1.7233	0.5469	0.0911	14.1768	4.4925	13.7802
7	C3	44.10	3.3193	2.2146	1.4809	15.0133	28.4792	15.5648
8	i-C4	58.12	1.6162	1.4297	1.2368	3.5901	10.6953	3.8811
9	n-C4	58.12	4.0632	3.8252	3.4801	6.5826	22.0997	7.2182
10	i-C5	72.15	2.9444	3.0419	2.9900	1.9119	8.0158	2.1620
11	n-C5	72.15	4.1376	4.3419	4.3227	1.9743	8.9033	2.2581
12	C6	86.16	4.5705	4.9334	5.0415	0.7287	3.9011	0.8586
13	C7	100.20	19.8607	21.6426	22.3367	0.9976	6.3417	1.2165

14	C8	114.23	15.0077	16.4043	16.9936	0.2232	1.6838	0.2830
15	C9	128.28	10.4805	11.4657	11.8924	0.0506	0.4479	0.0668
16	C10+	160.99	18.4132	20.1517	20.9151	0.0095	0.1135	0.0138
17	Benzene	78.11	0.1247	0.1351	0.1386	0.0145	0.0808	0.0172
18	Toluene	92.13	0.4338	0.4735	0.4897	0.0133	0.0893	0.0164
19	E-Benzene	106.17	0.2831	0.3096	0.3209	0.0027	0.0211	0.0034
20	Xylenes	106.17	1.0386	1.1359	1.1777	0.0085	0.0685	0.0109
21	n-C6	86.18	6.3697	6.8977	7.0705	0.7804	4.3993	0.9287
22	224Trimethylp	114.24	0.6584	0.7181	0.7420	0.0260	0.1669	0.0318
	MW		101.63	108.31	109.87	30.89	61.43	32.14
	Stream Mole Ratio		1.0000	0.9137	0.9100	0.0863	0.0037	0.0900
	Heating Value	[BTU/SCF]				1805.20	3427.55	1871.66
	Gas Gravity	[Gas/Air]				1.07	2.12	1.11
	Bubble Pt. @ 100F	[psia]	166.49	22.28	8.55			
	RVP @ 100F	[psia]	283.14	81.19	51.38			
	Spec. Gravity @ 100F		0.661	0.670	0.671			

EPN: LOAD1

Tank Truck Loading Emissions

Daily Loading	500	bbl/day
Annual Loadout Amount:	7665	Mgal/yr
Maximum Gallons per Hour:	5000	gal/hr
Control Efficiency	98%	

Saturation Factor (Submerged Dedicated):	0.6	
* True Vapor Pressure of Liquid Loaded:	9.00	psia
* Molecular Weight of Vapors:	50	
Temperature '(R) @ 80F:	540	

Pollutant	Emission Factor (lb/1000gal)*	Reference	Control Efficiency	EMISSIONS Annual (TPY)
VOC_{total}	6.23	AP-42	-----	0.4775

Example Calculations:

VOC: (12.46*[(S*P*M)/T,540])*(Mgal/yr)/2000 = VOC TPY

Saturation Factor (Submerged Dedicated):	0.6	
* True Vapor Pressure of Liquid Loaded:	9.00	psia
* Molecular Weight of Vapors:	50	
Temperature '(R) @ 100F:	560	

Pollutant	Emission Factor (lb/1000gal)*	Reference	Control Efficiency	Short Term Emissions lb/hr
VOC_{total}	6.01	AP-42	-----	0.6008

Example Calculations:

VOC: (12.46*[(S*P*M)/T,540])*(Mgal/yr) = VOC lb/hr

* Emisssions were calculated using AP-42, Table 5.2.5
* Input data from Fesco Analysis 7-2-09
* Vapor Pressure - AP42 - Table 7.1-2

Speciation Table

Component	Mole Wt	Mole%	lb/mol Mix	Wt%	Percentage	EMISSIONS lbs/hr	EMISSIONS TPY
Methane	16.043	52.8958	8.486	27.580	27.6%	VOC Speciation	
Nitrogen	28.013	0.0000	0.000	0.000	0.0%		
Carbon Dioxide	44.01	0.0000	0.000	0.000	0.0%		
Ethane	30.07	14.1768	4.263	13.855	13.9%		
Hydrogen Sulfide	34.08	0.0000	0.000	0.000	0.0%		
Propane	44.097	15.0133	6.620	21.516	21.5%	0.1293	0.1027
Iso-butane	58.124	3.5901	2.087	6.782	6.8%	0.0407	0.0324
N-Butane	58.124	6.5826	3.826	12.435	12.4%	0.0747	0.0594
Iso-Pentane	72.151	1.9119	1.379	4.483	4.5%	0.0269	0.0214
N-Pentane	72.151	1.9743	1.424	4.630	4.6%	0.0278	0.0221
N-Hexane	86.07	0.7287	0.627	2.038	2.0%	0.0122	0.0097
Cyclohexane	84.16	0.0000	0.000	0.000	0.0%	0.0000	0.0000
Heptanes	100.21	0.9976	1.000	3.249	3.2%	0.0195	0.0155
Methylcyclohexane	96.17	0.0000	0.000	0.000	0.0%	0.0000	0.0000
224-Trimethylpentane	114.22	0.0260	0.030	0.097	0.1%	0.0006	0.0005
Benzene	78.11	0.0145	0.011	0.037	0.0%	0.0002	0.0002
Toluene	92.14	0.0133	0.012	0.040	0.0%	0.0002	0.0002
Ethylbenzene	106.17	0.0027	0.003	0.009	0.0%	0.0001	0.0000
Xylenes	106.16	0.0085	0.009	0.029	0.0%	0.0002	0.0001
Hexanes +	92.12	0.7804	0.719	2.336	2.3%	0.0140	0.0112
C8 Heavies	96.09	0.2833	0.272	0.885	0.9%	0.0053	0.0042
		31.93	30.769	100.000	100%		
		98.9998	VOC 58.566				

Notes:

Gas Analysis - Questar Applied Technology, 1/3/2013, ML Investments 1-10

Facility Flare Calculations

EPN: FLR1

Pilot Combustion Emissions						
				FACTORS	EMISSIONS	
		Pollutant	Reference	lb/MMBtu	lbs/hr	TPY
Hours of Operation	8,760	NOx	AP-42	0.068	0.0052	0.0229
Hours per Day	24	CO	AP-42	0.310	0.0238	0.1044
Throughput (SCFD)	1,500	THC	AP-42	0.140	0.0108	0.0471
Hourly Flowrate (SCFH)	63	VOC	THC %		0.0025	0.0108
Lower heating value (BTU/SCF)	1,230	SO2	AP-42	0.001	0.0001	0.0003
Combustion Rate	0.08	PM10 / soot	AP-42	0.001	0.0001	0.0003
		PM2.5 / soot	AP-42	0.001	0.0001	0.0003

Calculation Notes: *VOCs taken from gas analysis listed below*

Emission Factors are from AP-42 - 13.5

Waste Gas (Tank Vapors) Combustion Emissions						
				FACTORS	EMISSIONS	
		Pollutant	Reference	lb/MMBtu	lbs/hr	TPY
Hours of Operation	8,760	NOx	AP-42	0.068	0.3485	1.5264
Hours per Day	24	CO	AP-42	0.310	1.5888	6.9587
Throughput (SCFD)	100,000	THC	AP-42	0.140	0.7175	3.1427
Hourly Flowrate (SCFH)	4,167	VOC	THC %		0.4202	1.8405
Lower heating value (BTU/SCF)	1,230	SO2	AP-42	0.001	0.0051	0.0224
Combustion Rate	5.13	PM10 / soot	AP-42	0.001	0.0051	0.0224
		PM2.5 / soot	AP-42	0.001	0.0051	0.0224

Calculation Notes: *VOCs taken from gas analysis listed below*

Emission Factors are from AP-42 - 13.5

Field Gas or Pilot Gas

Component	Mole Wt	Mole%	lb/mol Mix	Wt%	Percentage	EMISSIONS lbs/hr	EMISSIONS TPY
Methane	16.043	84.8561	13.613	66.981	67.0%	VOC Speciation	
Nitrogen	28.013	0.4883	0.137	0.673	0.7%		
Carbon Dioxide	44.01	0.1433	0.063	0.310	0.3%		
Ethane	30.07	6.2131	1.868	9.192	9.2%		
Hydrogen Sulfide	34.08	0.0000	0.000	0.000	0.0%		
Propane	44.097	4.0209	1.773	8.724	8.7%	0.0002	0.0009
Iso-butane	58.124	0.9324	0.542	2.666	2.7%	0.0001	0.0003
N-Butane	58.124	1.5751	0.916	4.505	4.5%	0.0001	0.0005
Iso-Pentane	72.151	0.5374	0.388	1.908	1.9%	0.0000	0.0002
N-Pentane	72.151	0.5433	0.392	1.929	1.9%	0.0000	0.0002
N-Hexane	86.07	0.2249	0.194	0.952	1.0%	0.0000	0.0001
Cyclohexane	84.16	0.0342	0.029	0.142	0.1%	0.0000	0.0000
Heptanes	100.21	0.1201	0.120	0.592	0.6%	0.0000	0.0001
Methylcyclohexane	96.17	0.0266	0.026	0.126	0.1%	0.0000	0.0000
224-Trimethylpentane	114.22	0.0068	0.008	0.038	0.0%	0.0000	0.0000
Benzene	78.11	0.0035	0.003	0.013	0.0%	0.0000	0.0000
Toluene	92.14	0.0021	0.002	0.010	0.0%	0.0000	0.0000
Ethylbenzene	106.17	0.0003	0.000	0.002	0.0%	0.0000	0.0000
Xylenes	106.16	0.0005	0.001	0.003	0.0%	0.0000	0.0000
Hexanes +	92.12	0.2421	0.223	1.097	1.1%	0.0000	0.0001
C8 Heavies	96.09	0.0290	0.028	0.137	0.1%	0.0000	0.0000
		8.30	20.324	100.000	100%		
		100.0000	VOC 22.8				

Notes:

Gas Analysis - Questar Applied Technology, 1/3/2013, ML Investments 1-10

Waste Gas

Component	Mole Wt	Mole%	lb/mol Mix	Wt%	Percentage	EMISSIONS lbs/hr	EMISSIONS TPY
Methane	16.043	52.8958	8.486	27.580	27.6%	VOC Speciation	
Nitrogen	28.013	0.0000	0.000	0.000	0.0%		
Carbon Dioxide	44.01	0.0000	0.000	0.000	0.0%		
Ethane	30.07	14.1768	4.263	13.855	13.9%		
Hydrogen Sulfide	34.08	0.0000	0.000	0.000	0.0%		
Propane	44.097	15.0133	6.620	21.516	21.5%	0.0904	0.3960
Iso-butane	58.124	3.5901	2.087	6.782	6.8%	0.0285	0.1248
N-Butane	58.124	6.5826	3.826	12.435	12.4%	0.0523	0.2289
Iso-Pentane	72.151	1.9119	1.379	4.483	4.5%	0.0188	0.0825
N-Pentane	72.151	1.9743	1.424	4.630	4.6%	0.0195	0.0852
N-Hexane	86.07	0.7287	0.627	2.038	2.0%	0.0086	0.0375
Cyclohexane	84.16	0.0000	0.000	0.000	0.0%	0.0000	0.0000
Heptanes	100.21	0.9976	1.000	3.249	3.2%	0.0137	0.0598
Methylcyclohexane	96.17	0.0000	0.000	0.000	0.0%	0.0000	0.0000
224-Trimethylpentane	114.22	0.0260	0.030	0.097	0.1%	0.0004	0.0018
Benzene	78.11	0.0145	0.011	0.037	0.0%	0.0002	0.0007
Toluene	92.14	0.0133	0.012	0.040	0.0%	0.0002	0.0007
Ethylbenzene	106.17	0.0027	0.003	0.009	0.0%	0.0000	0.0002
Xylenes	106.16	0.0085	0.009	0.029	0.0%	0.0001	0.0005
Hexanes +	92.12	0.7804	0.719	2.336	2.3%	0.0098	0.0430
C8 Heavies	96.09	0.2833	0.272	0.885	0.9%	0.0037	0.0163
		31.93	30.769	100.000	100%		
		98.9998	VOC 58.6				

Notes:

Gas Analysis - Questar Applied Technology, 1/3/2013, ML Investments 1-10

Alta Mesa Services, LP
Well Site Facility - GHG Emission Summary

GHG Pollutant	Compressor Engines	Well Head Heater	Line Heater	Heater Treater	Flare	Emission Totals
	ENG1	WHHTR1	LNHTR1	HTRTR1	FLR1	
	Metric Ton CO2e	Metric Ton CO2e	Metric Ton CO2e	Metric Ton CO2e	Metric Ton CO2e	
CO2	2211.0111	23.2228	232.2276	464.4552	4797.8222	**7728.7389**
CH4	0.8757	0.0092	0.0920	0.1840	1.9003	**3.0612**
N2O	1.2927	0.0136	0.1358	0.2716	2.8052	**4.5189**
Total GHG Metric Ton CO2e						**7736.32**

EPN: ENG1
Compressor Engine

Manufacturer's Rated Horsepower	610	hp
Fuel Input	0.007804	MMBtu/hp-hr
Operating Schedule	8760	hrs/yr

Global Warming Potentials	
CH4	21
N2O	310

Pollutant	Reference	Control Efficiency	Emission Factors	Factor Units	Short Term Emissions (kg/hr)	Annual Emissions (kg/yr)	**Metric Ton CO2e**
CO2	EPA GHG Factors	-----	53.02	kg/mmBtu	252.3985	2211011.1	**2211.0**
CH4	EPA GHG Factors	-----	0.001	kg/mmBtu	0.0048	41.70	**0.8757**
N2O	EPA GHG Factors	-----	0.0001	kg/mmBtu	0.0005	4.17	**1.2927**

Calculation Notes:
Factor Data based on EPA's GHG Published Emission Factors(11/7/2011)

EPN:	WHHTR1
Name/Type	Well Head Heater
Heater Rating (mmBtu/hr)	0.05
Operating Hours	8760
mmBtu/yr	438
Fuel Heat Value (Btu/SCF)	1230

Global Warming Potentials	
CH_4	21
N_2O	310

Pollutant	Emission Factor	Factor Units	Reference	Annual Emissions (kg/yr)	Metric Ton CO_2e
CO_2	53.02	kg/mmBtu	EPA GHG Factors	23,222.76	**23.2228**
CH_4	0.001	Kg/mmBtu	EPA GHG Factors	0.44	**0.0092**
N_2O	0.0001	Kg/mmBtu	EPA GHG Factors	0.04	**0.0136**

Calculation Notes:
Factor Data based on EPA's GHG Published Emission Factors(11/7/2011)

EPN:	LNHTR1
Name/Type	Line Heater
Heater Rating (mmBtu/hr)	0.5
Operating Hours	8760
mmBtu/yr	4380
Fuel Heat Value (Btu/SCF)	1230

Global Warming Potentials	
CH4	21
N2O	310

Pollutant	Emission Factor	Factor Units	Reference	Annual Emissions (kg/yr)	Metric Ton CO2e
CO2	53.02	kg/mmBtu	EPA GHG Factors	232,227.60	**232.2276**
CH4	0.001	Kg/mmBtu	EPA GHG Factors	4.38	**0.0920**
N2O	0.0001	Kg/mmBtu	EPA GHG Factors	0.44	**0.1358**

Calculation Notes:
Factor Data based on EPA's GHG Published Emission Factors(11/7/2011)

EPN:	HTRTR1
Name/Type	Heater Treater
Heater Rating (mmBtu/hr)	1
Operating Hours	8760
mmBtu/yr	8760
Fuel Heat Value (Btu/SCF)	1230

Global Warming Potentials	
CH4	21
N2O	310

Pollutant	Emission Factor	Factor Units	Reference	Annual Emissions (kg/yr)	Metric Ton CO2e
CO2	53.02	kg/mmBtu	EPA GHG Factors	464,455.20	**464.4552**
CH4	0.001	Kg/mmBtu	EPA GHG Factors	8.76	**0.1840**
N2O	0.0001	Kg/mmBtu	EPA GHG Factors	0.88	**0.2716**

Calculation Notes:
Factor Data based on EPA's GHG Published Emission Factors(11/7/2011)

EPN:	FLR1
Name/Type	Flare
Heater Rating (mmBtu/hr)	10.33
Operating Hours	8760
mmBtu/yr	90490.8
Fuel Heat Value (Btu/SCF)	1230

Global Warming Potentials	
CH4	21
N2O	310

Pollutant	Emission Factor	Factor Units	Reference	Annual Emissions (kg/yr)	Metric Ton CO2e
CO2	53.02	kg/mmBtu	EPA GHG Factors	4,797,822.22	**4797.8222**
CH4	0.001	Kg/mmBtu	EPA GHG Factors	90.49	**1.9003**
N2O	0.0001	Kg/mmBtu	EPA GHG Factors	9.05	**2.8052**

Calculation Notes:
Factor Data based on EPA's GHG Published Emission Factors(11/7/2011)

APPENDIX B – AMBIENT AIR QUALITY IMPACT ANALYSES

M E M O R A N D U M DRAFT

DATE:	August 11, 2016
TO:	Kelli Wetzel, Permit Writer, Air Program
FROM:	Kevin Schilling, Stationary Source Modeling Coordinator, Air Program
PROJECT:	P-2015.0051 PROJ 61598, PTC for Alta Mesa Services, ML Investments 1-3 Well Site Facility in Payette County, ID
SUBJECT:	Demonstration of Compliance with IDAPA 58.01.01.203.02 (NAAQS) and 203.03 (TAPs) as it relates to air quality impact analyses.

Contents

Acronyms, Units, and Chemical Nomenclature

AAC	Acceptable Ambient Concentration of a non-carcinogenic TAP
AACC	Acceptable Ambient Concentration of a Carcinogenic TAP
acfm	Actual cubic feet per minute
AERMAP	The terrain data preprocessor for AERMOD
AERMET	The meteorological data preprocessor for AERMOD
AERMOD	American Meteorological Society/Environmental Protection Agency Regulatory Model
Alta Mesa	Alta Mesa Services, LP
Appendix W	40 CFR 51, Appendix W – Guideline on Air Quality Models
BPIP	Building Profile Input Program
BRC	Below Regulatory Concern
CFR	Code of Federal Regulations
CMAQ	Community Multi-Scale Air Quality modeling system
CO	Carbon Monoxide
DEM	Digital Elevation Map
DEQ	Idaho Department of Environmental Quality
EL	Emissions Screening Level of a TAP
EPA	United States Environmental Protection Agency
GEP	Good Engineering Practice
Idaho Air Rules	Rules for the Control of Air Pollution in Idaho, located in the Idaho Administrative Procedures Act 58.01.01
ISCST3	Industrial Source Complex Short Term 3 dispersion model
K	Kelvin
m	Meters
m/sec	Meters per second
NAAQS	National Ambient Air Quality Standards
NAD83	North American Datum of 1983
NED	National Elevation Dataset
NO	Nitrogen Oxide
NO_2	Nitrogen Dioxide
NOx	Oxides of Nitrogen
NWS	National Weather Service
O_3	Ozone
Pb	Lead
PM_{10}	Particulate matter with an aerodynamic particle diameter less than or equal to a nominal 10 micrometers
$PM_{2.5}$	Particulate matter with an aerodynamic particle diameter less than or equal to a nominal 2.5 micrometers
ppb	parts per billion
PRIME	Plume Rive Model Enhancement
PTC	Permit to Construct
PTE	Potential to Emit
SIL	Significant Impact Level
SO_2	Sulfur Dioxide

TAP	Toxic Air Pollutant
TCEQ	Texas Commission on Environmental Quality
USGS	United States Geological Survey
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compounds
W&A	Wolcott & Associates ECS, LLC
$\mu g/m^3$	Micrograms per cubic meter of air

1.0 Summary

Alta Mesa Services, LP (Alta Mesa) submitted a Permit to Construct (PTC) application for a proposed oil and gas production well site facility, ML Investments 1-3, located 7 miles east, northeast of the Idaho/Oregon boundary at Ontario, Oregon, and about 6.2 miles north of New Plymouth, Idaho. The original PTC application was received on September 30, 2015. DEQ determined the application was incomplete on October 28, 2015. After additional data/analyses were received, the application was again determined incomplete on November 28, 2015, and again on December 30, 2015. On February 16, 2016, revised air impact analyses were received by DEQ and the application was determined complete on April 22, 2016.

This memorandum provides a summary of the ambientair impact analyses submitted with the permit application. It also describes DEQ's review of those analyses, DEQ's verification and sensitivity analyses, additional clarifications, and conclusions.

Project-specific ambient air quality impact analyses, involving atmospheric dispersion modeling of estimated emissions associated with the facility, were submitted to DEQ to demonstrate that the facility would not cause or significantly contribute to a violation of any ambient air quality standard as required by the Idaho Administrative Procedures Act 58.01.01.203.02 and 203.03 (Idaho Air Rules Section 203.02 and 203.03).

Wolcott & Associates ECS, LLC (W&A), on behalf of Alta Mesa, prepared the PTC application and performed the air impact analyses for this project to demonstrate compliance with National Ambient Air Quality Standards (NAAQS) and Toxic Air Pollutants (TAPs). The DEQ review of submitted data and analyses summarized by this memorandum addressed only the rules, policies, methods, and data pertaining to the air impact analyses used to demonstrate that estimated emissions associated with operation of the facility will not cause or significantly contribute to a violation of any applicable air quality standard. This review did not address/evaluate compliance with other rules or analyses not pertaining to the air impact analyses. Evaluation of emissions estimates was the responsibility of the DEQ permit writer and is addressed in the main body of the DEQ Statement of Basis, and emissions calculation methods were not evaluated in this modeling review memorandum.

The submitted information and analyses, in combination with DEQ's verification analyses: 1) utilized appropriate methods and models; 2) was conducted using reasonably accurate or conservative model parameters and input data (review of emissions estimates was addressed by the DEQ permit writer); 3) adhered to established DEQ guidelines for new source review dispersion modeling; 4) showed either a) that estimated potential/allowable emissions are at a level defined as below regulatory concern (BRC) and do not require a NAAQS compliance demonstration; b) that predicted pollutant concentrations from emissions associated with the project as modeled were below Significant Impact Levels (SILs) or other applicable regulatory thresholds; or c) that predicted pollutant concentrations from emissions associated with the project as modeled, when appropriately combined with co-contributing sources and background concentrations, were below applicable NAAQS at ambient air locations where and when the project has a significant impact; 5) showed that TAP emissions increases associated with the project will not result in increased ambient air impacts exceeding allowable TAP increments.

Table 1 presents key assumptions and results to be considered in the development of the permit.

Idaho Air Rules require air impact analyses be conducted according to methods outlined in 40 CFR 51, Appendix W *Guideline on Air Quality Models* (Appendix W). Appendix W requires that air quality impacts be assessed using atmospheric dispersion models with emissions and operations representative of design capacity or as limited by a federally enforceable permit condition. The submitted information and analyses, in combination with DEQ's analyses, demonstrated to the satisfaction of the Department that operation of the proposed facility will not cause or significantly contribute to a violation of any ambient air quality standard, provided the key conditions in Table 1 are representative of facility design capacity or operations as limited by a federally enforceable permit condition. The DEQ permit writer should use Table 1 and other information presented in this memorandum to generate appropriate permit provisions/restrictions to assure the requirements of Appendix W are met with regard to emissions representing design capacity or permit allowable rates.

Table 1. KEY ASSUMPTIONS USED IN MODELING ANALYSES

Criteria/Assumption/Result	Explanation/Consideration
General Emissions Rates. Emissions rates used in the dispersion modeling analyses, as listed in this memorandum, must represent maximum potential emissions as given by design capacity or as limited by the issued permit for the specific pollutant and averaging period.	Compliance has not been demonstrated for emissions rates greater than those used in the modeling analyses (see Table 6).
Below Regulatory Concern for Criteria Pollutant Emissions. Maximum non-fugitive annual emissions of PM_{10}[a], $PM_{2.5}$[b], carbon monoxide (CO), sulfur dioxide (SO_2), and lead (Pb) are below levels identified as below regulatory concern (BRC) as per Idaho Air Rules Section 221, and the project would be exempt from permitting if it were not for uncontrolled emissions of some criteria pollutants exceeding BRC threshold levels.	Idaho Air Rules Section 203.02, requiring air impact analyses demonstrating compliance with NAAQS, is not applicable to pollutants having a project-emissions increase that is less than BRC levels, provided the project would have qualified for a BRC permitting exemption except for the emissions levels of another criteria pollutant exceeding the ton/year BRC threshold.
Stack Parameter Variability. Provided the equipment installed and operated at the ML Investments 1-3 site is representative of what was described in the application, moderate variability in operational parameters, other than a decrease in stack heights or the addition of structures not accounted for in the submitted analyses, will not change the conclusion of the NAAQS compliance demonstration. Such parameters include operational load levels of the engine, heaters, and flare, stack diameters, and stack exhaust temperatures.	DEQ performed a sensitivity analysis using values for emissions release parameters that were more conservative than those used in the submitted analyses. Results of sensitivity analyses still easily demonstrated compliance with NAAQS.

a. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
b. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.

2.0 Background Information

This section provides background information applicable to the project and the site where the facility is located. It also provides a brief description of the applicable air impact analyses requirements for the project.

2.1 Project Description

The ML Investments 1-3 facility will be an oil and gas gathering and processing facility. The PTC will address all air pollutant emitting activities at the site.

2.2 Proposed Location and Area Classification

The proposed facility will be located about 7.0 miles east, northeast of the Idaho/Oregon boundary at Ontario, Oregon, and about 6.2 miles north of New Plymouth, Idaho. It is located in Payette County, Idaho. This area is designated as an attainment or unclassifiable area for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), lead (Pb), ozone (O_3), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}), and particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers ($PM_{2.5}$). The area is not classified as non-attainment for any criteria pollutants.

2.3 Air Impact Analyses Required for All Permits to Construct

Idaho Air Rules Sections 203.02 and 203.03:

> *No permit to construct shall be granted for a new or modified stationary source unless the applicant shows to the satisfaction of the Department all of the following:*
>
> ***02. NAAQS.*** *The stationary source or modification would not cause or significantly contribute to a violation of any ambient air quality standard.*
>
> ***03. Toxic Air Pollutants.*** *Using the methods provided in Section 210, the emissions of toxic air pollutants from the stationary source or modification would not injure or unreasonably affect human or animal life or vegetation as required by Section 161. Compliance with all applicable toxic air pollutant carcinogenic increments and toxic air pollutant non-carcinogenic increments will also demonstrate preconstruction compliance with Section 161 with regards to the pollutants listed in Sections 585 and 586.*

Atmospheric dispersion modeling, using computerized simulations, is used to demonstrate compliance with both NAAQS and TAPs. Idaho Air Rules Section 202.02 states:

> ***02. Estimates of Ambient Concentrations.*** *All estimates of ambient concentrations shall be based on the applicable air quality models, data bases, and other requirements specified in 40 CFR 51 Appendix W (Guideline on Air Quality Models).*

2.4 Significant Impact Level and Cumulative NAAQS Impact Analyses

The Significant Impact Level (SIL) analysis for a new facility or proposed modification to a facility involves modeling estimated criteria air pollutant emissions from the facility or modification to determine the potential impacts to ambient air. Idaho Air Rules state that air impact analyses must be conducted according to methods outlined in 40 CFR 51, Appendix W (Guideline on Air Quality Models). Appendix W requires that impact analyses use emissions and operations representative of design capacity or as limited by a federally enforceable permit condition.

A facility or modification is considered to have a significant impact on air quality if maximum modeled impacts to ambient air exceed the established SIL listed in Idaho Air Rules Section 006 (referred to as a "significant contribution" in Idaho Air Rules) or as incorporated by reference as per Idaho Air Rules Section 107.03.b. Table 2 lists the applicable SILs.

If modeled maximum pollutant impacts to ambient air from the emissions sources associated with a new facility or modification exceed the SILs, then a cumulative NAAQS impact analysis is necessary to demonstrate compliance with NAAQS and Idaho Air Rules Section 203.02.

A cumulative NAAQS impact analysis for attainment area pollutants involves assessing ambient impacts from facility-wide potential/allowable emissions and emissions from any nearby co-contributing sources, and then adding a DEQ-approved background concentration value to the modeled result that is appropriate for the criteria pollutant/averaging-period at the facility location and the area of significant impact. The resulting pollutant concentrations in ambient air are then compared to the NAAQS listed in Table 2. The modeled value used for comparison to the applicable standard is referred to as the "design value" and is consistent with the statistical form of the standard. Table 2 also lists SILs and specifies the modeled design value that must be used for comparison to the NAAQS. NAAQS compliance is evaluated on a receptor-by-receptor basis for the modeling domain.

Table 2. APPLICABLE REGULATORY LIMITS

Pollutant	Averaging Period	Significant Impact Levels[a] ($\mu g/m^3$)[b]	Regulatory Limit[c] ($\mu g/m^3$)	Modeled Design Value Used[d]
PM_{10}[e]	24-hour	5.0	150[f]	Maximum 6th highest[g]
$PM_{2.5}$[h]	24-hour	1.2	35[i]	Mean of maximum 8th highest[j]
	Annual	0.3	12[k]	Mean of maximum 1st highest[l]
Carbon monoxide (CO)	1-hour	2,000	40,000[m]	Maximum 2nd highest[n]
	8-hour	500	10,000[m]	Maximum 2nd highest[n]
Sulfur Dioxide (SO_2)	1-hour	3 ppb[o] (7.8 $\mu g/m^3$)	75 ppb[p] (196 $\mu g/m^3$)	Mean of maximum 4th highest[q]
	3-hour	25	1,300[m]	Maximum 2nd highest[n]
	24-hour	5	365[m]	Maximum 2nd highest[n]
	Annual	1.0	80[r]	Maximum 1st highest[n]
Nitrogen Dioxide (NO_2)	1-hour	4 ppb (7.5 $\mu g/m^3$)	100 ppb[s] (188 $\mu g/m^3$)	Mean of maximum 8th highest[t]
	Annual	1.0	100[r]	Maximum 1st highest[n]
Lead (Pb)	3-month[u]	NA	0.15[r]	Maximum 1st highest[n]
	Quarterly	NA	1.5[r]	Maximum 1st highest[n]
Ozone (O_3)	8-hour	40 TPY VOC[v]	75 ppb[w]	Not typically modeled

a. Idaho Air Rules Section 006 (definition for significant contribution) or as incorporated by reference as per Idaho Air Rules Section 107.03.b.
b. Micrograms per cubic meter.
c. Incorporated into Idaho Air Rules by reference, as per Idaho Air Rules Section 107.
d. The maximum 1st highest modeled value is always used for the significant impact analysis unless indicated otherwise. Modeled design values are calculated for each ambient air receptor.
e. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
f. Not to be exceeded more than once per year on average over 3 years.
g. Concentration at any modeled receptor when using five years of meteorological data.
h. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
i. 3-year mean of the upper 98th percentile of the annual distribution of 24-hour concentrations.
j. 5-year mean of the 8th highest modeled 24-hour concentrations at the modeled receptor for each year of meteorological data modeled. For the SIL analysis, the 5-year mean of the 1st highest modeled 24-hour impacts at the modeled receptor for each year.
k. 3-year mean of annual concentration.
l. 5-year mean of annual averages at the modeled receptor.
m. Not to be exceeded more than once per year.
n. Concentration at any modeled receptor.
o. Interim SIL established by EPA policy memorandum.
p. 3-year mean of the upper 99th percentile of the annual distribution of maximum daily 1-hour concentrations.
q. 5-year mean of the 4th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year mean of 1st highest modeled 1-hour impacts for each year is used.
r. Not to be exceeded in any calendar year.
s. 3-year mean of the upper 98th percentile of the annual distribution of maximum daily 1-hour concentrations.
t. 5-year mean of the 8th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year mean of maximum modeled 1-hour impacts for each year is used.
u. 3-month rolling average.
v. An annual emissions rate of 40 ton/year of VOCs is considered significant for O_3.
w. Annual 4th highest daily maximum 8-hour concentration averaged over three years. The O_3 standard was revised (the notice was signed by the EPA Administrator on October 1, 2015) to 70 ppb. However, this standard will not be applicable for permitting purposes until it is incorporated by reference *sine die* into Idaho Air Rules.

If the cumulative NAAQS impact analysis indicates a violation of the standard, the permit may not be issued if the proposed project has a significant contribution (exceeding the SIL) to the modeled violation. This evaluation is made specific to both time and space. As an example, consider a hypothetical case where the SIL analysis indicates the project (new source or modification) has impacts exceeding the SIL and the cumulative impact analysis indicates a violation of the NAAQS. If project-specific impacts are below the SIL at the specific receptors showing the violations during the time periods when modeled violations occurred, then the project does not have a significant contribution to the specific violations.

Compliance with Idaho Air Rules Section 203.02 is generally demonstrated if: a) applicable specific criteria pollutant emissions increases are at a level defined as BRC, using the criteria established by DEQ regulatory interpretation[1]; or b) modeled impacts of the SIL analysis are below the applicable SIL or other level determined to be inconsequential to NAAQS compliance at all receptor locations; or c) modeled design values of the cumulative NAAQS impact analysis (modeling all emissions from the facility and co-contributing sources, and adding a background concentration) are less than applicable NAAQS at receptors where impacts from the proposed facility/modification exceeded the SIL or other identified level of consequence; or d) if the cumulative NAAQS analysis resulted in modeled NAAQS violations, the impact of proposed facility/modification to any modeled violation was inconsequential (typically assumed to be less than the established SIL) for that specific receptor and for the specific modeled time when the violation occurred.

2.5 Toxic Air Pollutant Analyses

Emissions of toxic substances are generally addressed by Idaho Air Rules Section 161:

> *Any contaminant which is by its nature toxic to human or animal life or vegetation shall not be emitted in such quantities or concentrations as to alone, or in combination with other contaminants, injure or unreasonably affect human or animal life or vegetation.*

Permitting requirements for toxic air pollutants (TAPs) from new or modified sources are specifically addressed by Idaho Air Rules Section 203.03 and require the applicant to demonstrate to the satisfaction of DEQ the following:

> *Using the methods provided in Section 210, the emissions of toxic air pollutants from the stationary source or modification would not injure or unreasonably affect human or animal life or vegetation as required by Section 161. Compliance with all applicable toxic air pollutant carcinogenic increments and toxic air pollutant non-carcinogenic increments will also demonstrate preconstruction compliance with Section 161 with regards to the pollutants listed in Sections 585 and 586.*

Per Section 210, if the total project-wide emissions increase of any TAP associated with a new source or modification exceeds screening emission levels (ELs) of Idaho Air Rules Section 585 or 586, then the ambient impact of the emissions increase must be estimated. If ambient impacts are less than applicable Acceptable Ambient Concentrations (AACs) for non-carcinogens of Idaho Air Rules Section 585 and Acceptable Ambient Concentrations for Carcinogens (AACCs) of Idaho Air Rules Section 586, then compliance with TAP requirements has been demonstrated.

Idaho Air Rules Section 210.20 states that if TAP emissions from a specific source are regulated by the Department or EPA under 40 CFR 60, 61, or 63, then a TAP impact analysis under Section 210 is not required for that TAP.

3.0 Analytical Methods and Data

This section describes the methods and data used in analyses to demonstrate compliance with applicable air quality impact requirements.

3.1 Emission Source Data

Emissions of criteria pollutants and TAPs resulting from operation of the Alta Mesa ML Investments 1-3 facility were provided by W&A for various applicable averaging periods.

Review and approval of estimated emissions is the responsibility of the DEQ permit writer, and the representativeness and accuracy of emissions estimates is not addressed in this modeling memorandum. DEQ air impact analyses review included verification that the potential emissions rates provided in the emissions inventory were properly used in the air impact analyses. The emission rates listed must represent the maximum allowable rate as averaged over the specified period.

Emissions rates used in the dispersion modeling analyses, as listed in this memorandum, should be reviewed by the DEQ permit writer and compared with those in the final emissions inventory. All modeled criteria air pollutant and TAP emissions rates must be equal to or greater than the facility's potential emissions as calculated in the PTC emissions inventory or proposed permit allowable emissions rates.

3.1.1 Modeling Applicability and Modeled Criteria Pollutant Emissions Rates

The ML Investments 1-3 project would qualify for a below regulatory concern (BRC) permit exemption as per Idaho Air Rules Section 221 if it were not for potential emissions of volatile organic compounds (VOCs), NOx, and CO exceeding the BRC threshold of 10 percent of emissions defined by Idaho Air Rules as significant. DEQ's regulatory interpretation policy of exemption provisions of Idaho Air Rules is that: "A DEQ NAAQS compliance assertion will not be made by the DEQ modeling group for specific criteria pollutants having a project emissions increase below BRC levels, provided the proposed project would have qualified for a Category I Exemption for BRC emissions quantities except for the emissions of another criteria pollutant.[1]" The interpretation policy also states that the exemption criteria of uncontrolled PTE not to exceed 100 ton/year (Idaho Air Rules Section 220.01.a.i) is not applicable when evaluating whether a NAAQS impact analyses is required. A permit will be issued limiting PTE below 100 ton/year, thereby negating the need to maintain calculated uncontrolled PTE under 100 ton/year.

The DEQ permit writer should assure that the final emissions inventory supports the assertion that facility-wide controlled PTE emissions of PM_{10}, $PM_{2.5}$, SO_2, and Pb are below BRC levels, as listed in Table 3. Table 3 also indicates that air impact analyses for CO and NO_2 are required for permit issuance.

An air impact analysis must be performed for pollutant emissions increases that do not qualify for the BRC exemption from the requirement to perform an air impact analysis. Facility-wide emissions of CO and NOx from operation of the ML Investments 1-3 facility do not qualify for the BRC exclusion because allowable emissions will exceed BRC threshold levels.

Table 3. CRITERIA POLLUTANT NAAQS COMPLIANCE DEMONSTRATION APPLICABILITY			
Criteria Pollutant	**BRC Level (ton/year)**	**Applicable Facility Wide PTE Emissions (ton/year)**	**Air Impact Analyses Required?**
PM_{10}[a]	1.5	0.47	No
$PM_{2.5}$[b]	1.0	0.46	No
Carbon Monoxide (CO)	10.0	19.3	Yes
Sulfur Dioxide (SO_2)	4.0	0.04	No
Nitrogen Oxides (NOx)	4.0	8.0	Yes
Lead (Pb)	0.06	NA[c]	No

a. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
b. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
c. Not calculated. Assumed to be below BRC levels based on the emissions source types.

Site-specific air impact modeling analyses may not be necessary for some pollutants, even where such emissions do not qualify for the BRC exemption. DEQ has developed modeling thresholds, below which a site-specific modeling analysis is not required. DEQ generic modeling analyses that were used to develop the modeling thresholds provide a conservative SIL analysis for projects with emissions below identified threshold levels. Project-specific modeling applicability thresholds are provided in the *Idaho Air Modeling Guideline*[2]. These thresholds were based on assuring an ambient impact of less than the established SIL for specific pollutants and averaging periods.

If project-specific total emissions rates of a pollutant are below Level I Modeling Thresholds, then project-specific air impact analyses are not necessary for permitting. Use of Level II Modeling Thresholds are conditional, requiring DEQ approval. DEQ approval is based on dispersion-affecting characteristics of the emissions sources such as stack height, stack gas exit velocity, stack gas temperature, distance from sources to ambient air, presence of elevated terrain, and potential exposure to sensitive public receptors.

DEQ determined that Level II Modeling Thresholds are not appropriate for the proposed project. Level II thresholds were based on modeling of a hypothetical source with less conservative parameters than was used in modeling to support Level I thresholds. Table 4 compares dispersion-affecting parameters associated with the proposed project to those used in modeling analyses establishing the Level II thresholds. DEQ determined Level II Modeling Applicability Thresholds were not appropriate for the site on the basis of the short stack heights of the sources and the very short distance from sources to ambient air. Table 5 provides a summary of the site-specific modeling applicability analysis. Site-specific modeling analyses were not required for CO or Pb, on the basis of project emissions below Level I Modeling Applicability Thresholds. Site-specific modeling analyses were required for 1-hour and annual NO_2 because potential emissions exceeded Level I Modeling Applicability Thresholds and Level II Thresholds were not appropriate for the site.

Ozone (O_3) differs from other criteria pollutants in that it is not typically emitted directly into the atmosphere. O_3 is formed in the atmosphere through reactions of VOCs, NOx, and sunlight. Atmospheric dispersion models used in stationary source air permitting analyses (see Section 3.3.3) cannot be used to estimate O_3 impacts resulting from VOC and NOx emissions from an industrial facility. O_3 concentrations resulting from area-wide emissions are predicted by using more complex airshed models such as the Community Multi-Scale Air Quality (CMAQ) modeling system. Use of the CMAQ model is very resource intensive and DEQ asserts that performing a CMAQ analysis for a particular permit application is not typically a reasonable or necessary requirement for air quality permitting.

Table 4. COMPARISON OF DISPERSION PARAMETERS BETWEEN LEVEL II THRESHOLD MODELING AND THE PROPOSED PROJECT		
Parameter	**Analyses for Level II Modeling**	**Proposed Project**
Stack Height (meters)	15	<6.1 for all sources
Stack Temperature at Exit (°F)	260	1,162 for engine 1,832 for flare
Stack Gas Velocity at Exit (meters/second)	20	53.4 for engine 20 for flare
Total Flow Volume (acfm)	33,288	3,673 for engine 15,165 for flare
Distance to Ambient Air (meters)	100	8.5 for engine 12 for flare
Presence of Buildings	10m X 10m X 5m high building	small engine building and storage silos
Potential for Exposure to Sensitive Receptors	Moderate	Low

Table 5. SITE-SPECIFIC MODELING APPLICABILITY ANALYSIS RESULTS					
Pollutant	**Averaging Period**	**Emissions**	**Level I Modeling Thresholds**	**Level II Modeling Thresholds**[a]	**Site-Specific Modeling Required**
NOx	1-hour	1.82 lb/hr	0.20	2.4	Yes
	Annual	7.99 ton/yr	1.2	14	Yes
CO	1-hour, 8-hour	4.4 lb/hr	15	175	No
Pb	monthly	<14 lb/month	14		No

[a] Level II Modeling Thresholds were not approved by DEQ for this project.

Addressing secondary formation of O_3 within the context of permitting a new stationary source has been somewhat addressed in EPA regulation and policy. As stated in a letter from Gina McCarthy of EPA to Robert Ukeiley, acting on behalf of the Sierra Club (letter from Gina McCarthy, Assistant Administrator, United States Environmental Protection Agency, to Robert Ukeiley, January 4, 2012):

> *. . . footnote 1 to sections 51.166(I)(5)(I) of the EPA's regulations says the following: "No de minimis air quality level is provided for ozone. However, any net emission increase of 100 tons per year or more of volatile organic compounds or nitrogen oxides subject to PSD would be required to perform an ambient impact analysis, including the gathering of air quality data."*
>
> *The EPA believes it unlikely a source emitting below these levels would contribute to such a violation of the 8-hour ozone NAAQS, but consultation with an EPA Regional Office should still be conducted in accordance with section 5.2.1.c. of Appendix W when reviewing an application for sources with emissions of these ozone precursors below 100 TPY."*

DEQ determined it was not appropriate or necessary to require a quantitative source specific O_3 impact analysis because allowable emissions estimates of VOCs and NOx are below the 100 tons/year threshold.

Secondary Particulate Formation

The impact from secondary particulate formation resulting from emissions of NOx, SO_2, and/or VOCs was assumed by DEQ to be negligible on the basis of the magnitude of emissions and the short distance from emissions sources to locations where maximum PM_{10} and $PM_{2.5}$ impacts are anticipated.

Emissions Rates Used in Impact Analyses

Table 6 lists the emissions rates used for specified averaging periods in the air impact modeling analyses. These rates must be representative of PTE as indicated by design capacity or as limited by an enforceable permit provision.

Table 6. EMISSIONS RATES USED IN IMPACT MODELING ANALYSES

Source Modeled Identification Code	Description	UTM[a] Coordinates (meters)		Emissions (pounds/hour)	
		Easting	Northing	1-Hour NO_2	Annual NO_2
ENG1	Caterpillar G398TA Engine	515645	4878848	1.344	1.344
FLR1	Plant Flare	515659	4878910	0.3537	0.3537
WHHTR1	Well Head Heater	515620	4878868	0.0041	0.0041
LNHTR1	Line Heater	515625	4878864	0.0407	0.0407
HTRTR1	Heater Treater	515634	4878857	0.0813	0.0813

a. Universal Transverse Mercator

3.1.2 Toxic Air Pollutant Emissions Rates

TAP emissions regulations under Idaho Air Rules Section 210 are only applicable to new or modified sources constructed after July 1, 1995. TAP compliance for the ML Investments 1-3 facility was demonstrated on a facility-wide basis.

Many of the TAP emissions sources at the Alta Mesa ML Investments 1-3 facility are regulated under 40 CFR 60, 61, or 63. These sources are exempt from TAP rules as per Idaho Air Rules Section 210 and were excluded from the TAP modeling applicability calculation.

After excluding emissions from sources exempt from the TAPs rules, no project-wide emissions of any TAP exceeded the applicable emissions screening levels (ELs) of Idaho Air Rules Section 585 or Section 586. Consequently, air impact modeling analyses were not required to demonstrate that impacts of TAP emissions are below the applicable ambient increment standards expressed in Idaho Air Rules Section 585 and 586.

3.1.3 Emissions Release Parameters

Table 7 provides emissions release parameters, including stack height, stack diameter, exhaust temperature, and exhaust velocity for emissions sources modeled in the air impact analyses.

W&A provided detailed documentation and justification of emissions release parameters within the *Air Impact Modeling Analyses Report* (Section 4.3), submitted as part of the application on February 16, 2016. Parameters represent best or conservative design information at the time of permit application submittal. DEQ performed sensitivity analyses to evaluate whether NAAQS compliance is still assured if release parameters change somewhat with final design. If release parameters change substantially with final design such that parameters no longer are a conservative representation of the emissions sources, then these air impact analyses could be effectively invalidated and may not satisfy the requirements of Idaho Air Rules Section 203.02 and 203.03. Substantial changes from what was submitted in the application would include: 1) a decrease in stack height by more than about 10 percent; 2) a decrease in stack gas flow temperature by more than about 20 percent; 3) a change in source location by more than 10 meters, especially if closer to an ambient air boundary or closer to the design value receptor location; 4) construction of buildings in the vicinity of emissions sources that could cause plume downwash.

Table 7. POINT SOURCE STACK PARAMETERS USED INIMPACT MODELING ANALYSES							
Release Point	Description	UTM[a] Coordinates		Stack Height (m)	Stack Gas Flow Temp. (K)[c]	Stack Flow Velocity (m/sec)[d]	Stack Dia. (m)
		Easting (m)[b]	Northing (m)				
ENG1	Catepillar G398TA Engine	515645	4878848	6.1	900, 720[e]	53.4, 16.6[e]	0.203, 0.305[e]
FLR1	Plant Flare	515659	4878910	6.1	1273	20.0	0.675, 0.37[e]
WHHTR1	Well Head Heater	515620	4878868	3.7	422	22.3, 11.7[e]	0.152
LNHTR1	Line Heater	515625	4878864	3.7	422	22.3, 11.7[e]	0.152
HTRTR1	Heater Treater	515634	4878857	3.7	422	22.3, 11.7[e]	0.152

a. Universal Transverse Mercator.
b. Meters.
c. Kelvin.
d. Meters/second. All sources release uninterrupted in the vertical direction (not horizontal or rain capped releases).
e. Values used in DEQ verification/sensitivity analyses where such values are different from those used in the analyses submitted with the application.

Engine Release Parameters

DEQ recommended that W&A estimate stack parameters for internal combustion (IC) engines using methods provided in the Washington State Department of Ecology document, *Suitability of Diesel-Powered Emergency Generators for Air Quality General Order of Approval: Evaluation of Control Technology, Ambient Impacts, and Potential Approval Criteria*, published in June 2006. The engine exhaust flow was based on the horsepower (hp) rating of the engine (610 hp) by the following equation from the guidance:

$$\frac{0.284\ m^3/sec}{100\ hp} \times 610\ hp = 1.732\ m^3/sec$$

The guidance recommends using a 44.6 meter/second stack gas exit velocity and then calculating the diameter that would result in a total flow equal to the exhaust flow calculated by the equation above. W&A indicated in Table 4-4 of the submitted modeling report that an exit velocity of 23.7 meters/second was used in the impact analyses, calculated on the basis of a 12-inch stack diameter and maintaining the 1.73 cubic meter/second flow. This is inconsistent with the parameters listed in Table 4-3 of the modeling report and the submitted model input files. The model input files indicate that an exhaust exit velocity of 53.4 meters/second was used with a 0.203-meter stack diameter, still maintaining the 1.73 cubic meter/second flow.

The discrepancy in exhaust flow velocity and stack diameter present in the modeling report could affect the ability to demonstrate NAAQS compliance. Higher exhaust exit velocity results in a higher plume momentum flux, which results in higher plume rise and lower estimated ground-level impacts. However, because of the high temperature of the exhaust, the buoyancy flux may dominate plume rise calculations in the model under most conditions. To address this concern, DEQ performed sensitivity analyses using the larger stack diameter and resulting lower exhaust exit velocity. DEQ sensitivity analyses are discussed in Section 4.1.2 of this memorandum.

W&A estimated exhaust temperatures using a table in the Department of Ecology's guidance that lists exit gas temperatures for various power ratings of engines, interpolating between the value of 897 Kelvin for a 500 hp engine and 1,100 Kelvin for a 6,900 hp engine.

DEQ performed sensitivity analyses using more conservative parameters for the engine exhaust. These adjusted parameters were as follows:

- A flow rate of 70 percent of what was used in the submitted analyses to account for operations at a reduced rate. This results in a 1.21 cubic meters/second flow rate.
- A stack diameter of 0.305 meters, resulting in a corresponding exhaust exit velocity of 16.6 meters/second for a 1.21 cubic meter/second flow.
- An exhaust temperature reduction by 20 percent to 720 Kelvin.

Flare Release Parameters

Modeling impacts from an open flame flare presents challenges because the appropriate method for estimating stack release parameters is not readily evident for point source model inputs of stack diameter, stack gas exist velocity, and stack gas exit temperature. Various methods have been developed to calculate appropriate release parameter values for flares, all primarily involving the heat input of the gas stream flared and the radiative heat loss. W&A used a method specified by the Texas Commission on Environmental Quality (TCEQ). The application provided a copy of the TCEQ guidance for using the method and a description of the technical basis for the approach.

The TCEQ methods for calculating model input parameters for a flare are very similar to those used for flares in the EPA screening model SCREEN3 for flares, as described in the SCREEN3 User's Guide[3]. The TCEQ method sets the exit gas velocity and temperature constant at 20 meters/second and 1,273 Kelvin, respectively. The stack diameter is then calculated based on the heat released from the combustion of gases in the flare by the following equation:

$$D = [(q_n)(10^{-6})]^{1/2}$$
$$q_n = q[1 - 0.048(MW)^{1/2}]$$

where:

D = effective stack diameter (meters)
q = gross heat released (calories/second)
q_n = net heat released (calories/second)
MW = weighted average molecular weight of gas flared

The gross heat release of 6.23 E5 calories/second was provided by W&A and was based on the molecular composition of the flared gas, expressed as mole/day of specific compounds. The weighted average molecular weight was calculated based on the mole fraction of specific compounds in the flared gas and the molecular weight of those compounds. The net heat released was then calculated at 4.55 E5 calories/second, giving an effective diameter of 0.675 meters.

Provided the composition of the flared gas is accurate or conservative for the source, DEQ asserts that the TCEQ method is appropriate for estimating model input parameters for the flare. To provide additional assurance, DEQ performed sensitivity analyses using the SCREEN3 method. DEQ also adjusted input parameters of the SCREEN3 method to represent a more conservative assessment. These adjustments included the following:

- Not taking credit for additional release height according to a calculation of "length of flame" of the operating flare.

- Calculate the effective diameter (which affects the buoyancy flux of the emitted plume) using a value of half that of q_n.

In the SCREEN3 method, the net heat released is calculated by:

$$q_n = (0.45)q$$

where:

q = gross heat released (calories/second)
q_n = net heat released (calories/second)

The effective diameter is then calculated by $D = 9.88E\text{-}4(q_n)^{0.5}$

Using a gross heat release (q) of 6.23 E5 calories/second results in a net heat release (q_n) of 2.80 E5 calories/second. The effective diameter (D) was then calculated at 0.52 meters. DEQ used an additional measure of conservatism by recalculating the effective diameter (D) by assuming only half the net heat release, equal to 1.4 E5 calories/second, giving a value of D = 0.37 meters.

The SCREEN3 method directs the use of a stack gas release velocity of 20 meters/second and a stack gas temperature of 1,273 Kelvin, identical to that used for the TCEQ method.

The stack height used for a flare release for the SCREEN3 method can be increased from the physical height of the flare to account for the flame length according to the following equation:

$$Ha = Hs + [(4.56E\text{-}3)(q^{0.478})]$$

where:

Ha = effective stack height (meters)
Hs = physical height of flare (meters)
q = gross heat release (calories/second)

DEQ's sensitivity analyses did not account for an increased release height, adding an additional level of conservatism to the results.

Process Heater Release Parameters

Specific process heaters have not yet been selected for the facility. Release parameters were estimated by W&A using a Utah Department of Environmental Quality approach for modeling generic natural gas well sites, as described in the submitted application. A 3.0 million British thermal unit/hour (MMBtu/hr) heater was estimated to produce an exhaust flow of 860 actual cubic feet/minute (acfm) at 600° F, resulting in a 22.2 meter/second exit velocity, given a design specified stack diameter at the exit of 0.5 feet (0.152 meters). As a conservative measure, W&A modeled the sources with an exhaust temperature of 300° F (422 K) rather than 600° F, reducing the effect of plume rise from thermal buoyancy.

DEQ performed a combustion evaluation on the source to verify flow rates. At 100 percent load and combusting with 5.0 percent excess air, a flow of 906 acfm was predicted at a temperature of 300° F. DEQ sensitivity analyses were then performed by conservatively using half the calculated flow to account for operations at less than design capacity. Emissions rates were not correspondingly reduced with the flow associated with reduced load, thereby adding another level of conservatism to the analyses.

3.2 Background Concentrations

Background concentrations are used if a cumulative NAAQS air impact modeling analysis is needed to demonstrate compliance with applicable NAAQS. DEQ provided W&A with appropriate background concentrations for 1-hour and annual averaged NO_2.

Background concentrations were determined by DEQ using the following web-based design value concentration tool: Northwest International Air Quality Environmental Science and Technology Consortium (NW AIRQUEST) Lookup 2009-2011 Design Values of Criteria Pollutants (http://lar.wsu.edu/nw-airquest/lookup.html). These design value air pollutant levels are based on regional scale air pollution modeling of Washington, Oregon, and Idaho, with values influenced by monitoring data as a function of distance from the monitor. The background concentration tool estimated the following background values for the Alta Mesa sites in the Payette area: 1-hour NO_2 = 52.6 $\mu g/m^3$; annual NO_2 = 4.7 $\mu g/m^3$. During review of the PTC application, DEQ extracted background values that are specific to the ML Investments 1-3 site and they were slightly less than the originally provided values: 1-hour NO_2 = 43.2 $\mu g/m^3$; annual NO_2 = 3.0 $\mu g/m^3$. These refined background values are appropriate for impacts that are within several hundred meters of the facility boundary.

3.3 NAAQS Impact Modeling Methodology

This section describes the modeling methods used by the applicant's consultant and DEQ to demonstrate preconstruction compliance with applicable air quality standards.

3.3.1 General Overview of Impact Analyses

W&A performed the project-specific air pollutant emissions inventory and air impact analyses that were submitted with the application. Results of the submitted information/analyses, in combination with DEQ's verification and sensitivity analyses, demonstrate compliance with applicable air quality standards to DEQ's satisfaction, provided the facility is operated as described in the submitted application and in this memorandum.

Table 8 provides a brief description of parameters used in the modeling analyses.

Table 8. MODELING PARAMETERS		
Parameter	**Description/Values**	**Documentation/Addition Description**
General Facility Location	Payette, Idaho	The area is an attainment or unclassified area for all criteria pollutants.
Model	AERMOD	AERMOD with the PRIME downwash algorithm, version 15181.
Meteorological Data	Langley Gulch site data, Ontario, OR, surface data, Boise upper air data	December 2008 - November 2009. See Section 3.3.5 of this memorandum for additional details of the meteorological data.
Terrain	Considered	USGS National Elevation Dataset (NED) files to establish elevations of ground level receptors. AERMAP was used to determine each receptor elevation and hill height scale.
Building Downwash	Considered	Plume downwash was considered for the structures associated with the facility. BPIP-PRIME was used to evaluate building dimensions for consideration of downwash effects in AERMOD.
Receptor Grid	Grid 1	DEQ: 10-meter spacing along the property boundary out to about 100 meters
	Grid 2	DEQ: 25-meter spacing out to 500 meters.
	Grid 3	DEQ: 100-meter spacing out to 7,000 meters.

3.3.2 Modeling protocol and Methodology

A modeling protocol, describing data and methods proposed for the project, was not initially submitted to DEQ. W&A corresponded with DEQ on modeling methods and data after Alta Mesa received a notice of incomplete application for the ML Investments 1-3 project. Final project-specific modeling and other required impact analyses were generally conducted using data and methods as discussed with DEQ and as described in the *Idaho Air Quality Modeling Guideline*[2].

3.3.3 Model Selection

Idaho Air Rules Section 202.02 requires that estimates of ambient concentrations be based on air quality models specified in 40 CFR 51, Appendix W (Guideline on Air Quality Models). The refined, steady state, multiple source, Gaussian dispersion model AERMOD was promulgated as the replacement model for ISCST3 in December 2005. AERMOD retains the single straight line trajectory of ISCST3, but includes more advanced algorithms to assess turbulent mixing processes in the planetary boundary layer for both convective and stable stratified layers.

AERMOD version 15181 was used by W&A for the modeling analyses to evaluate air pollutant impacts of the facility. This version was the current version at the time the application was received by DEQ.

3.3.4 NO_2 Chemistry

The atmospheric chemistry of NO, NO_2, and O_3 complicates accurate prediction of NO_2 impacts resulting from NOx emissions. The conversion of NO to NO_2 can be conservatively addressed through the use of several methods as outlined in a 2014 EPA NO_2 Modeling Clarification Memorandum[4]. The guidance outlines a three-tiered approach:

- Tier 1 – assume full conversion of NO to NO_2 where total NOx emissions are modeled and modeled impacts are assumed to be 100 percent NO_2.
- Tier 2 – use an ambient ratio to adjust impacts from the Tier 1 analysis.
- Tier 3 – use a detailed screening method to account for $NO/NO_2/O_3$ chemistry such as the Ozone Limiting Method (OLM) or the Plume Volume Molar Ratio Method (PVMRM).

W&A used the Tier 2 Ambient Ratio Method 2 (ARM2) to conservatively account for NO/NO_2 chemistry. The EPA-specified default minimum and maximum NO_2/NOx ratio of 0.5 and 0.9 were specified in the model, respectively. The NO_2 Modeling Clarification Memorandum outlines criteria for the acceptability of using ARM2 for a project. DEQ accepted the use of ARM2 for the proposed ML Investments 1-3 project on the basis of the following:

- A Tier 1 impact assessment of the facility, assuming full conversion of NO to NO_2, resulted in NO_2 modeled impacts below the lower end of the EPA-identified threshold of 150-200 ppb (282-376 $\mu g/m^3$). The lower end of the range is recommended for areas with higher background ozone levels and higher background NO_2 values. The Tier 1 1-hour NO_2 design value for the ML Investments 1-3 site is 97 $\mu g/m^3$, well below the lower end of the threshold.

- If the Tier I analysis impacts exceed the 282-376 $\mu g/m^3$ threshold, use of the ARM2 method may still be acceptable if the NO_2/NOx in-stack ratio (ISR) of the primary source is at or below 0.2; an ISR above 0.2 may still be acceptable if the minimum ISR of 0.5 is specified as input to the ARM2 algorithm. Since the facility's design value impact from the Tier 1 analysis is less than the 282-376 $\mu g/m^3$ threshold, assessment of the ISR was not necessary. As a conservative measure, W&A used ARM2 with the minimum ISR of 0.5 rather than 0.2.

- If the Tier I analysis impacts exceed the 282-376 $\mu g/m^3$ threshold, use of the ARM2 method may still be acceptable if the ambient background O_3 levels are not greater than 80 – 90 ppb for more than seven days per year. Since the facility's design value impact from the Tier 1 analysis is less than the 282-376 $\mu g/m^3$ threshold, assessment of the background O_3 was not necessary. However, ARM2 justification for other DEQ air permitting projects assessed background O_3 based on data collected from Middleton, Idaho, between 2002 and 2006. Those data indicated that on average, O_3 exceeds 80 ppb for 2.8 days/year and exceeds 90 ppb for 0.6 days/year.

3.3.5 Meteorological Data

DEQ provided A&W with model-ready meteorological data, using site data from a station at the Langley Gulch Power Plant, located along Interstate Highway 84, south of New Plymouth. The Langley Gulch site is about 10 miles south of the ML Investments 1-3 site. Onsite data collected included wind speed, wind direction, delta temperature, and solar radiation. The station was operated to collect one year of data for permitting of the Langley Gulch Power Plant, starting in December of 2008. These data were supplemented with National Weather Service (NWS) surface data from the Ontario, Oregon, site KONO, including one minute ASOS data. Upper air data were obtained from the NWS site in Boise, Idaho.

DEQ processed the Langley Gulch meteorological data using AERMET Version 15181, AERMINUTE Version 15271, and AERSURFACE 13016. Wind speed values were collected as vector means and were handled as such in AERMOD.

DEQ determined that meteorological data from the Langley Gulch site were more representative of conditions at various Alta Mesa sites than data collected at the Boise Airport. Alta Mesa representatives asserted that using a 5-year dataset from Boise would be more defensible and appropriate than using the single year of data from the Langley Gulch site. To address this concern, DEQ performed a sensitivity analysis using surface meteorological data from Boise for the years 2011 through 2015. Results of this analysis are provided in Section 4.1.2 of this memorandum and indicate that use of the Langley Gulch meteorological is conservative, resulting in a higher design value than Boise meteorological data. This is not an indication that Langley Gulch data are more appropriate or more representative of site conditions than Boise Airport data. It simply eliminates the need to evaluate comparative appropriateness and representativeness because NAAQS compliance is demonstrated for both datasets.

3.3.6 Effects of Terrain on Modeled Impacts

Submitted ambient air impact analyses used terrain data extracted from United States Geological Survey (USGS) National Elevation Dataset (NED) files in the WGS84 datum (approximately equal to the NAD83 datum).

The terrain preprocessor AERMAP Version 11103 was used by W&A to extract the elevations from the NED files and assign them to receptors in the modeling domain in a format usable by AERMOD. AERMAP also determined the hill-height scale for each receptor. The hill-height scale is an elevation value based on the surrounding terrain which has the greatest effect on that individual receptor. AERMOD uses those heights to evaluate whether the emissions plume has sufficient energy to travel up and over the terrain or if the plume will travel around the terrain.

3.3.7 Facility Layout

DEQ verified proper identification of the site location, equipment locations, and the ambient air boundary by comparing a graphical representation of the modeling input file to plot plans submitted in the application. Aerial photographs on Google Earth (available at https://www.google.com/earth) were used to assure that horizontal coordinates were accurate as described in the application. Google Earth could not be used to verify the position of all sources and structures because the facility is not yet in existence.

3.3.8 Effects of Building Downwash on Modeled Impacts

Potential downwash effects on emissions plumes were accounted for in the model by using building dimensions and locations (locations of building corners, base elevation, and building heights). Dimensions and orientation of proposed buildings were used as input to the Building Profile Input Program for the Plume Rise Model Enhancements downwash algorithm (BPIP-PRIME) to calculate direction-specific dimensions and Good Engineering Practice (GEP) stack height information for input to AERMOD. The only structures at the site evaluated for downwash were a 10-foot high structure housing the generator and six 20-foot high storage tanks. The addition of any other structures at the site could cause plume downwash and potentially invalidate the analyses described in this memorandum for NAAQS compliance demonstration purposes.

3.3.9 Ambient Air Boundary

Ambient air is defined in Section 006 of the Idaho Air Rules as "that portion of the atmosphere, external to buildings, to which the general public has access." Ambient air was considered areas external to the Alta Mesa ML Investments 1-3 facility, and the facility is fenced to preclude public access. DEQ has determined that measures described in the application to preclude public access to areas of the site excluded from ambient air are adequate.

3.3.10 Receptor Network

Table 8 describes the receptor grid used in the submitted analyses. The receptor grid used in the submitted analyses met the minimum recommendations specified in the *Idaho Air Quality Modeling Guideline*[2] and DEQ determined that it was adequate to resolve maximum modeled impacts. A receptor grid extending out beyond 7,000 meters from the facility boundary was not necessary for these analyses because pollutants are emitted from relatively short stacks that will cause maximum impacts to be located very close to the source, typically at or very close to the ambient air boundary.

3.3.11 Good Engineering Practice Stack Height

An allowable good engineering practice (GEP) stack height may be established using the following equation in accordance with Idaho Air Rules Section 512.03.b:

H = S + 1.5L, where:

- H = good engineering practice stack height measured from the ground-level elevation at the base of the stack.
- S = height of the nearby structure(s) measured from the ground-level elevation at the base of the stack.
- L = lesser dimension, height or projected width, of the nearby structure.

All Alta Mesa ML Investments 1-3 sources are below GEP stack height. Therefore, it is important to account for plume downwash caused by structures at the facility.

3.3.12 Neighboring Co-Contributing Emissions Sources

Given the magnitude of emissions quantities of the proposed project and the low release height, maximum impacts are anticipated to occur within 100 meters of the emissions sources, with impacts rapidly decreasing beyond this point. Neighboring well sites, with similar emissions quantities to those associated with the ML Investments 1-3 facility, located beyond a distance of about 400 meters (0.25 miles) would be very unlikely to measurably contribute to the modeled design value impacts.

DEQ's review of the ML Investments 1-3 facility revealed that the proposed ML Investments 2-3 facility is only about 225 meters (0.15 miles) from the western ambient air boundary. DEQ performed a sensitivity analysis to evaluate the potential impact of the neighboring ML Investments 2-3 emissions on the design value impacts associated with the ML Investments 1-3 facility. The type of emissions sources, magnitude of potential emissions, and release parameters of the ML Investments 2-3 facility are identical to those of the ML Investments 1-3 facility, except for the location of the release points. Table 9 lists the emissions sources of the ML Investments 2-3 facility, and results of the DEQ sensitivity analysis are provided in Section 4.1.2 of this memorandum.

Table 9. EMISSIONS SOURCES OF THE ML INVESTMENTS 2-3 FACILITY

Release Point	Description	UTM[a] Coordinates Easting (m)[b]	UTM[a] Coordinates Northing (m)	Stack Height (m)	Stack Gas Flow Temp. (K)[c]	Stack Flow Velocity (m/sec)[d]	Stack Dia. (m)	1-Hour NO_2 Emissions (lb/hr)[e]
ENG1A	Catepillar G398TA	516313	4877372	6.1	900	53.4	0.203	1.344
FLR1A	Plant Flare	516266	4877379	6.1	1273	20.0	0.675	0.3537
WHHTR1A	Well Head Heater	516304	4877392	3.7	422	22.3	0.152	0.0041
LNHTR1A	Line Heater	516306	4877388	3.7	422	22.3	0.152	0.0407
HTRTR1A	Heater Treater	516308	4877381	3.7	422	22.3	0.152	0.0813

a. Universal Transverse Mercator.
b. Meters.
c. Kelvin.
d. Meters/second. All sources release uninterrupted in the vertical direction (not horizontal or rain capped releases).
e. pounds per hour.

4.0 NAAQS Impact Modeling Results

4.1 Results for NAAQS Analyses

4.1.1 Submitted Analyses

A 1-hour and annual NO_2 cumulative NAAQS analysis was performed for the ML Investments 1-3 facility. Results of the impact analyses are provided in Table 10. Figure 1 shows 1-hour NO_2 design value impact contours from the facility throughout the modeled domain. Figure 2 shows 1-hour NO_2 impacts in the immediate vicinity of the facility.

Design value impacts were primarily driven by impacts from the IC engine. The design value impact of the flare only was 10.0 μg/m³ and the design value impact of the heaters only was 33.0 μg/m³. The maximum design value impact was located about 22 meters from the southeastern side of the ambient air boundary, about 56 meters east of the engine stack and 80 meters south southeast of the flare.

Emissions of CO were below DEQ Level 1 Modeling Thresholds, assuring that impacts are below the SIL. Air impact analyses of other criteria pollutants were not required because emissions were below levels defined as BRC. Idaho Air Rules Section 203.02, requiring air impact analyses demonstrating compliance with NAAQS, is not applicable to pollutants having a project-emissions increase that is less than BRC levels, provided the project would have qualified for a BRC permitting exemption except for the emissions levels of another criteria pollutant exceeding the ton/year BRC threshold.

Table 10. RESULTS FOR SUBMITTED AIR IMPACT ANALYSES

Pollutant	Modeled Design Value Impact (μg/m³)[a]	Background Value (μg/m³)	Total Maximum Concentration (μg/m³)	NAAQS[b] (μg/m³)	Percent of NAAQS
1-hour NO_2	87.3	52.6 (43.2)[c]	139.9 (130.5)	188	74
Annual NO_2	2.8	4.7 (3.0)[c]	7.5 (5.8)	100	8

a. micrograms per cubic meter.
b. National Ambient Air Quality Standard.
c. Refined background concentration for site.

4.1.2 DEQ Sensitivity and Verification Analyses

DEQ performed both verification analyses and sensitivity analyses of impacts associated with the proposed ML Investments 1-3 project. Verification analyses assured that model output results, given the specified input parameters, are accurate and reproducible. Sensitivity analyses are performed to evaluate how sensitive model results are to changes in the input parameters, such as source exhaust flow rates, exhaust temperatures, etc.

Verification Analysis Results

The 1-hour NO_2 design value result, equal to the maximum impact of modeled 8th highest of daily 1-hour maximum modeled concentrations, from the DEQ verification analysis was 87.3 μg/m³. This value is identical to that obtained from the analysis performed by W&A and submitted with the application. The location of the maximum impact was also identical to that of the submitted analysis.

Figure 1: Concentration Contours in Micrograms per Cubic Meter

for 1-Hour NO2 Design Value Impacts

Background Concentrations not Included

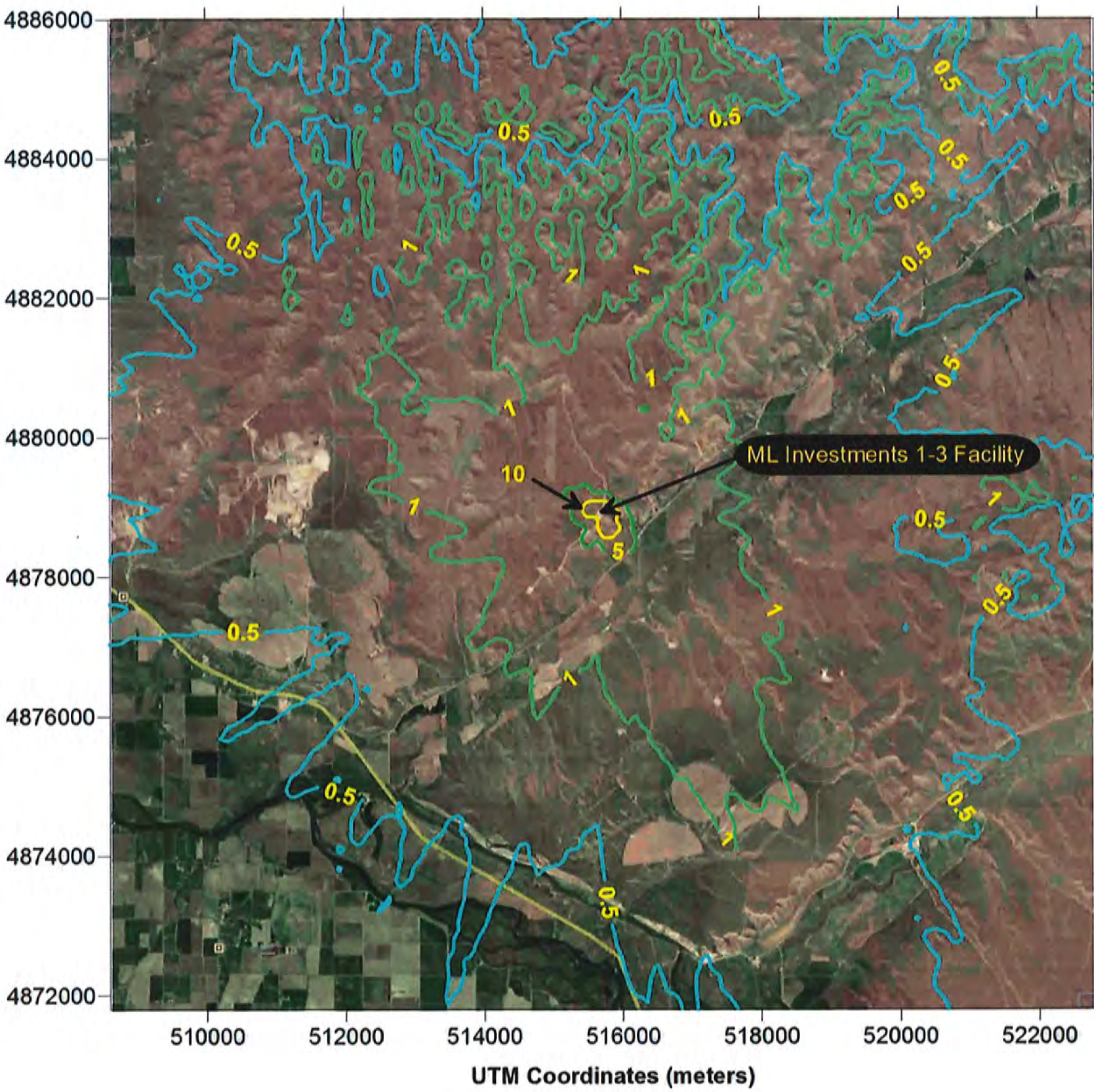
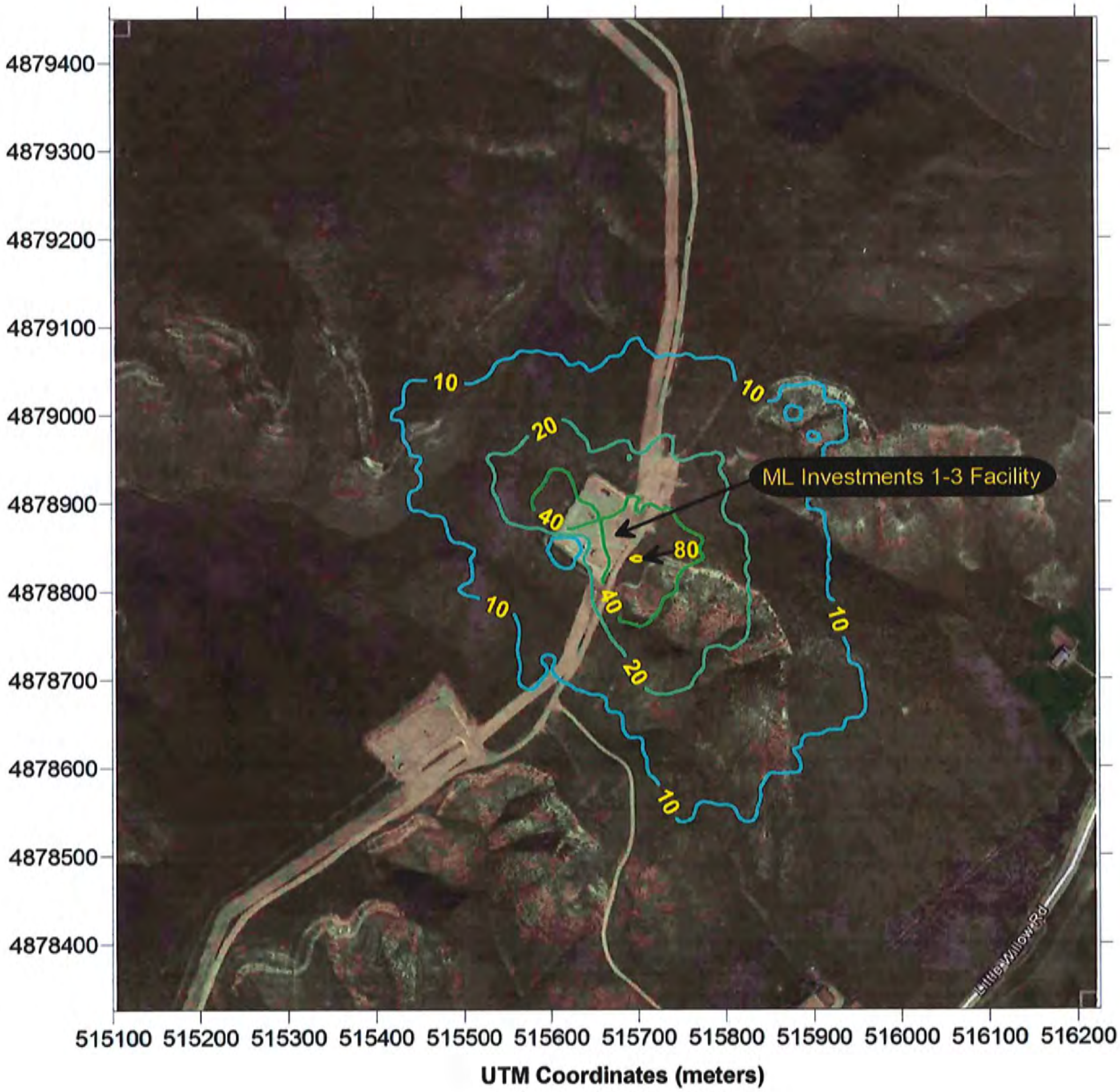


Figure 2: Concentration Contours in Micrograms per Cubic Meter

for 1-Hour NO2 Design Value Impacts

Background Concentrations not Included



Stack Parameter Sensitivity Analysis

DEQ increased the conservatism of modeled release parameters to evaluate the importance of assuring that "as-built" characteristics still assure NAAQS compliance if certain parameters vary slightly from those used in the impact analyses. Emissions rates were not adjusted.

The following adjustments were made to modeled release parameters for indicated sources:

- Engine: A flow rate of 70 percent of that used in the submitted analyses to account for operation at a reduced load.
- Engine: A larger stack diameter of 0.305 meters compared to 0.203 meters.
- Engine: With the flow and stack diameter adjusted as indicated above, the flow velocity was 16.6 meters/second. This is well below the flow velocity of 53.4 meters/second that was used in the submitted analyses.
- Flare: The EPA SCREEN3 method was used rather than the TCEQ method. As an additional level of conservatism, the effective stack height was not increased according to flame height calculations, as directed by the SCREEN3 method.
- Flare: The value for net heat released in the flare was half that used in the submitted analyses. This results in a lower total flow, a lower buoyancy flux, lower plume rise, and higher resulting ground-level concentrations in most instances.
- Heaters: DEQ used a combustion evaluation to calculate the exhaust volumetric flow rate for a 3.0 MMBtu/hour combustion source with a 300° F exhaust temperature, and then adjusted the flow rate to half the combustion evaluation value to account for a decreased operational rate (without a corresponding decrease in emissions). The result was a decrease in the exhaust flow rate from 22.3 meters/second to 11.7 meters/second.

The stack parameter sensitivity analyses for 1-hour NO_2 resulted in a design value impact of 105.8 $\mu g/m^3$. A total impact of 149.0 $\mu g/m^3$ was generated when the revised 43.2 $\mu g/m^3$ background value was added to the modeled result. Although this modeled impact is above the 130.5 $\mu g/m^3$ impact indicated by the submitted analysis, it is still well below the applicable 188 $\mu g/m^3$ NAAQS, especially considering the level of conservatism in numerous stack parameters.

Meteorological Data Sensitivity Analysis

DEQ performed a meteorological data sensitivity analysis to evaluate the need for a comparative assessment of data appropriateness between Langley Gulch data and Boise Airport data. The maximum 1-hour NO_2 modeled design value, using the 5-year Boise meteorological dataset, was 32.7 $\mu g/m^3$. This well below the 90.2 $\mu g/m^3$ design value obtained with the 1-year Langley Gulch meteorological dataset. Reasons for the difference are uncertain, although use of a 5-year dataset tends to result in slightly lower design values because the 1-hour NO_2 design value is a multiyear average of the design value of each year.

The location of the maximum design value when using the Langley Gulch data was near the southeast ambient air boundary. The maximum design value when using Boise meteorological data was in the same general location, but 20 meters south. These locations are fairly consistent with the primary wind direction and each receptor location is somewhat elevated with respect to the base elevation at the location of the engine.

Co-Contributing Source Impact Assessment

DEQ performed a sensitivity analysis to evaluate the potential for the co-contributing ML Investments 2-3 facility to contribute to cumulative 1-hour NO_2 impacts from the ML Investments 1-3 facility. When emissions from the ML Investments 2-3 facility, located approximately 225 meters west of the ML Investments 1-3 facility, were added to the cumulative 1-hour NO_2 impact analysis, the design value impact did not change from 87.3 $\mu g/m^3$.

4.2 Results for TAPs Impact Analyses

Site-specific TAP impact analyses were not required for the ML Investments 1-3 facility because applicable facility-wide emissions of all TAPs are below ELs.

5.0 Conclusions

The information submitted with the PTC application, combined with DEQ air impact verification analyses, demonstrated to DEQ's satisfaction that emissions from the Alta Mesa ML Investments 1-3 facility will not cause or significantly contribute to a violation of any ambient air quality standard.

References

1. *Policy on NAAQS Compliance Demonstration Requirements.* Idaho Department of Environmental Quality Policy Memorandum. July 11, 2014.

2. *State of Idaho Guideline for Performing Air Quality Impact Analyses.* Idaho Department of Environmental Quality. September 2013. State of Idaho DEQ Air Doc. ID AQ-011. Available at http://www.deq.idaho.gov/media/1029/modeling-guideline.pdf.

3. *SCREEN3 Model User's Guide.* U.S. Environmental Protection Agency. Office of Air Quality Planning and Standards. Emission, Monitoring, and Analysis Division. Research Triangle Park, NC. EPA 454/B-95-004. September 1995.

4. *Clarification on the Use of AERMOD Dispersion Modeling for Demonstrating Compliance with the NO_2 National Ambient Air Quality Standard.* Office of Air Quality Planning and Standards. Air Quality Modeling Group. Research Triangle Park, NC. Guidance memorandum from R. Chris Owen and Roger Brode to Regional Dispersion Modeling Contacts. September 30, 2014.

APPENDIX C – FACILITY DRAFT COMMENTS

No comments were received from the facility on August 24, 2016.

APPENDIX D – PROCESSING FEE

PTC Fee Calculation

Instructions:
Fill in the following information and answer the following questions with a Y or N. Enter the emissions increases and decreases for each pollutant in the table.

Company:	**Alta Mesa Services, LP - ML Investments 1-3**
Address:	**2.5 miles NE of Hwy 52 & Little Willow Rd.**
City:	**New Plymouth**
State:	**ID**
Zip Code:	**83661**
Facility Contact:	**Jennie Kent**
Title:	**Facilities Engineer**
AIRS No.:	**075-00024**

N	Does this facility qualify for a general permit (i.e. concrete batch plant, hot-mix asphalt plant)? Y/N
Y	Did this permit require engineering analysis? Y/N
N	Is this a PSD permit Y/N (IDAPA 58.01.01.205.04)

Emissions Inventory			
Pollutant	Annual Emissions Increase (T/yr)	Annual Emissions Reduction (T/yr)	Annual Emissions Change (T/yr)
NO_X	0.5	0	0.5
SO_2	0.0	0	0.0
CO	8.0	0	8.0
PM10	19.3	0	19.3
VOC	25.1	0	25.1
TAPS/HAPS	1.3	0	1.3
Total:	0.0	0	**54.2**
Fee Due	**$ 5,000.00**		

Comments: