

**ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION  
Air Permits Program**

**TECHNICAL ANALYSIS REPORT  
for  
Air Quality Control Construction Permit AQ1201CPT02**

**Exxon Mobil Corporation  
Point Thomson Production Facility**

**ESTABLISH POINT THOMSON PRODUCTION FACILITY**

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### Abbreviations/Acronyms

AAC	Alaska Administrative Code
AAAQS	Alaska Ambient Air Quality Standards
Department	Alaska Department of Environmental Conservation
BACT	Best Available Control Technology
C&D	Construction and Drilling
C&O	Construction and Operation
O&D	Operation and Drilling
CFR	Code of Federal Regulations
DLN	Dry Low NOx
EPA	Environmental Protection Agency
EU	Emission Unit
ExxonMobil	Exxon Mobil Corporation
HAP	Hazardous Air Pollutant
MR&Rs	Monitoring, Recording, and Reporting
NA	Not Applicable
NESHAPS	National Emission Standards for Hazardous Air Pollutants
NSPS	New Source Performance Standards
ORL	Owner Requested Limit
Point Thomson Facility	ExxonMobil Point Thomson Production Facility
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
RICE, ICE	Reciprocating Internal Combustion Engine, Internal Combustion Engine
SCR	Selective Catalytic Reduction
SIP	Alaska State Implementation Plan
TAR	Technical Analysis Report
ULSD	Ultra Low Sulfur Diesel
VE	Visible Emissions

### Units and Measures

gal/hr	gallons per hour
g/kWh	grams per kilowatt hour
g/hphr	grams per horsepower hour
hr/day	hours per day
hr/yr	hours per year
hp	horsepower
lb/hr	pounds per hour
lb/MMBtu	pounds per million British thermal units
lb/1000 gal	pounds per 1,000 gallons
kW	kilowatts
MMBtu/hr	million British thermal units per hour
MMscf/hr	million standard cubic feet per hour
ppmv	parts per million by volume
tpy	tons per year

### Pollutants

CO	Carbon Monoxide
CO <sub>2</sub> e	Carbon Dioxide Equivalent
GHG	Greenhouse Gases
HAP	Hazardous Air Pollutant
NOx	Oxides of Nitrogen
PM	Particulate Matter
PM-2.5	Particulate Matter with an aerodynamic diameter not exceeding 2.5 microns
PM-10	Particulate Matter with an aerodynamic diameter not exceeding 10 microns
SO <sub>2</sub>	Sulfur Dioxide
VOC	Volatile Organic Compound

## 1. INTRODUCTION

This Technical Analysis Report (TAR) provides the Alaska Department of Environmental Conservation's (Department's) basis for issuing Air Quality Control Construction Permit AQ1201CPT02 to Exxon Mobil Corporation (ExxonMobil) for their Point Thomson Production Facility (Point Thomson Facility). This is a project scope change to the original Prevention of Significant Deterioration (PSD) project issued under AQ1201CPT01. The original project triggered PSD review for nitrogen oxides (NO<sub>x</sub>), carbon monoxide (CO), particulate matter with an aerodynamic diameter not exceeding a nominal 2.5 micrometers (PM-2.5), and greenhouse gases (GHGs). The revised project still triggers PSD review for these same pollutants, as well as an additional pollutant: particulate matter with an aerodynamic diameter not exceeding a nominal 10 micrometers (PM-10). ExxonMobil is maintaining their owner requested limit (ORL) to avoid PSD review for sulfur dioxide (SO<sub>2</sub>). However, the application also triggers the minor permit requirements for portable oil and gas operations under 18 AAC 50.502(c)(2) as well as the minor permit requirements under 18 AAC 50.508(6) for revising or rescinding the terms and conditions of a Title I permit.

### 1.1 Description of Source

The Point Thomson Facility is located about 55 miles east of Prudhoe Bay on the eastern North Slope of Alaska. It is classified as an oil/gas exploration and production facility under North American Industrial Classification System code 211111. Exploration has shown that the area around the Point Thomson Facility contains large reserves of oil and gas. ExxonMobil will locate the facility on the Central Pad, an on-shore gravel pad. The facility includes construction camps, shops, offices, warehouses, storage units, electric power generating stations, power distribution facilities, drinking water treatment systems, wastewater treatment systems, waste management facilities, oil spill response equipment, emergency response equipment, communication equipment, airstrip, water access pad, and Alaska State C-1 Pad. The facility does not include the gravel mines, off-pad pipelines, and facilities on the East Pad and West Pad.

The facility will process approximately 200 million standard cubic feet per day of fuel gas to recover 10,000 barrels per day of condensate. ExxonMobil will use the produced fuel gas as the primary fuel for the turbines at the facility and will transport the hydrocarbons by a new pipeline that will tie into the existing Badami Sales Oil Pipeline.

### 1.2 Permit History

In January 2008, the Department issued AQ1201ORL01 to establish an operation camp and oil rigs at the East, West, and Central Pads of the Point Thomson Facility. The ORL permit limited emissions from 15 pieces of equipment authorized to operate at the camp to less than the minor permit thresholds in 18 AAC 50.502(c)(1).

On May 26, 2010, the Department issued AQ1201MSS01 to install and operate 64 pieces of stationary and mobile equipment at the Point Thomson Facility. The equipment included drilling rigs, boilers, heaters, a flare, an incinerator, storage tanks, and non-road engines. The permit established ORLs to enable the Point Thomson Facility to avoid classification as a PSD major source.

In a letter to the Department in April 2011, ExxonMobil requested the Department to rescind AQ1201MSS01 Revision 1. In a May 2011 response letter to ExxonMobil, the Department rescinded the permit and stated that any restart or continued operation of the emission units will be treated as new construction under applicable provisions of AS 46.14 and 18 AAC 50.

On August 20, 2012, the Department issued AQ1201CPT01 under PSD review to establish the Point Thomson Production Facility. Permit AQ1201CPT01 authorized installation and operation of several turbines, pumps, incinerators, generators, boilers, heaters, reciprocating internal combustion engines (RICES), and drilling Emission Units (EUs) to support construction, drilling and production operations. The permit also included ambient limits for protecting the ambient air quality standards and increments for pollutants that triggered PSD and an ORL for avoiding a PSD permit for SO<sub>2</sub>.

### **1.3 Application Description**

ExxonMobil submitted an application to revise the PSD Permit AQ1201CPT01 on November 2, 2012 and an addendum on December 13, 2012. ExxonMobil is requesting revisions to the permit based on changes to the final engineering design intended to maximize operational flexibility and to authorize the operation of two existing incinerators (EUs 246 and 247). The aforementioned revisions trigger classification as a PSD major source for PM-10.

ExxonMobil requested inclusion of applicable 40 CFR 60 Subpart OOOO, New Source Performance Standards Requirement for Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. The rule became effective on October 15, 2012.

ExxonMobil also requested inclusion of applicable 40 CFR 63 Subpart JJJJJ, National Emission Standards for Hazardous Air Pollutants (NESHAPs). While NESHAPs standards are not required to be included in a construction permit, ExxonMobil requested them to be included.

### **1.4 Project Description**

ExxonMobil plans to begin gravel placement for the Central Pad, installation of piles, and construction of airstrip, infield roads, and power generation in 2013. ExxonMobil plans to begin installation of equipment and modules for the Central Pad in 2014, install the turbines and other stationary equipment on the Central Pad in 2015, and start production in 2016.

The permanent production equipment at the facility will be two gas turbines, two dual fuel turbines, six reciprocating engines firing ultra low sulfur diesel (ULSD), two waste incinerators, and two gas flares. ExxonMobil will also use miscellaneous drilling and workover equipment to support their permanent operations. In addition, ExxonMobil will use several internal combustion engines (ICEs), a heater, and two additional waste incinerators during the construction phase of the project.

The Point Thomson permit application is the first PSD application received for the Northern Alaska Interstate Air Quality Control Region subsequent to the October 20, 2011 “trigger date” for PM-2.5 increment. The completeness date therefore sets the PM-2.5 “minor source baseline” date. The application defaulted complete on November 2, 2012. The minor source PM-2.5 baseline date for the Northern Alaska Interstate Air Quality Control Region is therefore November 2, 2012.

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## **2. EMISSIONS SUMMARY AND PERMIT APPLICABILITY**

### **2.1. Emissions Summary and Permit Applicability**

The applicant has proposed to construct and operate the source in three phases. They listed the EUs that they expect to operate in each phase. However, since the phases overlap, it is not possible to delineate the emissions for each phase. Some of the drilling activities during the construction phase overlap with the operation phase. The applicant calculated the combined emissions for the overlapping phases of construction and drilling (C&D), construction and operation (C&O), and operation and drilling (O&D).

During the construction and drilling phases, ExxonMobil will operate several non-road engines (NRE). The Department did not include NRE emissions in the emissions calculations because they do not count towards determining classification of the stationary source. Construction emissions are excluded from the determination of PSD applicability based on two provisions of 40 CFR 52.21. 40 CFR 52.21(b)(18) which describe secondary emissions as “emissions which would occur as a result of construction or operation of a major stationary source or major modification, but do not come from the major stationary source or the major modification itself.” 40 CFR 52.21(b)(4) states “Secondary emissions do not count in determining the potential to emit of a stationary source.” As a result, the PSD applicability analysis does not include the C&D and C&O phases.

Table 1 shows a summary of the Project’s potential to emit for the permanent phase for NO<sub>x</sub>, CO, PM-10, PM-2.5, VOC, SO<sub>2</sub>, and GHGs as carbon dioxide equivalent (CO<sub>2e</sub>). Table A-1 in Appendix A shows detail calculations for the O&D phase.

Due to the nature of GHGs and their incorporation into the definition of regulated NSR pollutant, the process for determining whether a source is emitting GHGs in an amount that would make the GHGs a regulated NSR pollutant includes a calculation of, and applicability threshold for, the source based on CO<sub>2</sub> equivalent (CO<sub>2</sub>e) emissions as well as its GHG mass emissions.

Consequently, when determining the applicability of PSD to GHGs, there is a two-part applicability process that evaluates both. The first step is to sum the CO<sub>2</sub>e emissions in tpy of the six GHGs in order to determine whether the source's emissions are a regulated NSR pollutant; and if so, sum the GHGs on a mass basis to determine if there is a major source or major modification of such emissions.

As shown in Table 1, the GHG emissions are 243,414 tpy and exceed 100,000 tons per year (tpy) of CO<sub>2</sub>e. Almost all of the CO<sub>2</sub>e<sup>1</sup> emissions are direct CO<sub>2</sub> emissions (less than 10 tons combined of direct methane (CH<sub>4</sub>) and nitrous oxide (N<sub>2</sub>O)). Therefore, summation of the GHGs on mass basis is greater than 250 tpy and the project is PSD for GHGs under 40 CFR 52.21(b)(49)(v)(a) and hence subject to PSD review for each regulated NSR pollutant that it has the potential to emit in quantities that exceed the significant thresholds listed in 40 CFR 52.21(b)(23)(i).

The Department is treating this application as a project scope change to the original project for establishing the Point Thomson project. The project was originally authorized under AQ1201CPT01. As shown in Table 1, the project had significant potential emissions for NO<sub>x</sub>, CO, and PM-2.5 above the thresholds in 40 CFR 52.21(b)(23)(i). Under the current permit action for project scope change, the stationary source also triggered PSD applicability for PM-10, under 40 CFR 52.21(b)(23)(i).

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<sup>1</sup> CO<sub>2</sub>e emissions = ((CO<sub>2</sub> EF) + (21 × CH<sub>4</sub> EF) + (310 × N<sub>2</sub>O EF))

**Table 1: Emissions from Stationary EUs at Point Thomson Facility, Tons per Year (tpy)**

Description	NO <sub>x</sub>	CO	PM-2.5	PM-10	VOC	SO <sub>2</sub>	CO <sub>2e</sub>
PTE as originally proposed for AQ1201CPT01	168.3	118.7	13.1	14.5	25.7	23.8	239,862
PTE for AQ1201CPT02	160.0	105.1	18.7	20.2	36.2	30.5	243,414
PSD Applicability Threshold	40	100	10	15	40	40	100,000
PSD Applicability Triggered?	<b>Yes</b>	<b>Yes</b>	<b>Yes</b>	<b>Yes</b>	No	No	<b>Yes</b>
<b>Assessable Emissions</b>	<b>160</b>	<b>105</b>	<b>N/A</b>	<b>20</b>	<b>36</b>	<b>31</b>	<b>N/A</b>
	<b>352</b>						

Table Notes:

SO<sub>2</sub> emissions are based on ULSD and fuel gas with a H<sub>2</sub>S content of 125 ppmv (turbines and higher pressure flare, except pilot and purge) and 300 ppmv (low pressure flare and pilot and purge of higher pressure flare).

Based PSD applicability threshold on 40 CFR 52.21(b)(1)(i)(b) and 40 CFR 52.21(b)(49)(v)(a)

Based threshold for BACT on 40 CFR 52.21(j)(2) and 40 CFR 52.21(b)(23)(i)

The stationary source contains a Portable Oil and Gas Operation. Therefore, this project also triggered a minor permit under 18 AAC 50.502(c)(2). This applicability determination should have been addressed but was overlooked in Permit AQ1201CPT01.

### 3. PSD PERMIT REQUIREMENTS

Under 18 AAC 50.306, the Permittee must satisfy the requirements under 40 CFR 52.21. The elements the Department must include in PSD permits are listed in 40 CFR 52.21(j) through (p). This section and associated sub-sections outline these provisions.

40 CFR 52.21(j)(1) requires that the major source meet the applicable local standards, state requirements established in the Alaska State Implementation Plan, and federal standards of performance in 40 CFR 60 and 61. While the source must meet each applicable emissions standards described in Sections 3.1 and 3.2 of this TAR, the standards and associated monitoring requirements will be carried forward into the Title V operating permit for the source. The Federal standards can be revised, in the future (if the standards change), in the Title V permit without the need to revise this Title I permit.

40 CFR 52.21(j)(2) requires a major stationary source to apply Best Available Control Technology (BACT) for each regulated New Source Review pollutant that has the potential to emit greater than the significant amounts listed in 40 CFR 52.21(b)(23)(i). Appendix B presents details of the BACT analysis for PM-10 which, due to this project modification, has exceeded the significant amount threshold of 15 tpy. The project is already classified under 18 AAC 50.306 as a PSD major source for NO<sub>x</sub>, CO, PM-2.5, and CO<sub>2</sub>.

40 CFR 52.21(k) through (o) requires that the source contain the requirements under each section as applicable:

40 CFR 52.21(k) - *Source Impact Analysis*: This includes a review of the allowable emissions increase concerning the Alaska Ambient Air Quality Standards and increments;

40 CFR 52.21(l) – *Air Quality Models*: Use of air quality models that are consistent with Appendix W of 40 CFR 51;

40 CFR 52.21(m) – *Air Quality Analysis*: Measured ambient air quality data, unless exempted under 40 CFR 52.21(i)(5);

40 CFR 52.21(n) - *Source Information*: Include all information about the source including a description of the nature, design capacity, location, schedule for modification and layout;

40 CFR 52.21(o) – *Additional Impact Analysis*: The source must review air quality impacts on the project area, such as visibility; and

40 CFR 52.21(p) – *Source Impacting Federal Class I Areas*: Review air quality impacts on the Federal Class I area.

The requirements under 40 CFR 52.21(k) through (p) are addressed in the modeling memorandum in Appendix C of this TAR.

### **3.1. Federal Emission Standards**

#### **3.1.1. New Source Performance Standards (NSPS) Standards for Turbines**

EUs 101 through 104 (listed in Table A-1, Appendix A) at the stationary source are stationary combustion turbines subject to NO<sub>x</sub> emission limits in Table 1 of the Appendix to Subpart KKKK of 40 CFR 60, because each has a heat input greater than 10 MMBtu/hr and was constructed after February 18, 2005.

The NSPS standards for EUs 101-104 are carried over from Permit AQ1201CPT01. Section 7 of the permit contains the NSPS limits and monitoring, recording, and reporting (MR&R) requirements that ensure the combustion turbines comply with the NSPS standards.

#### **3.1.2. NSPS Standards for Diesel Engines**

The source contains several emergency ICEs and fine water mist pumps that must comply with NO<sub>x</sub>, CO, PM emission limits in 40 CFR 60 Subpart IIII and 40 CFR 89.112. The 40 CFR 60 Subpart IIII affected engines at Point Thomson will meet the applicable emission standards for emergency engines. Section 7 of the permit contains conditions and MR&Rs for compliance with the NSPS requirements. The limits are revised as follows from Construction Permit AQ1201CPT01 to designate that EU 114 is an emergency engine and EUs 110 and 111 have an increased rating of 610 hp.

EU 114 must meet the limits for engines manufactured between 2006 and 2010 as emergency IC engines with displacement of less than 30 liters per cylinder, as applicable in 40 CFR 60.4201. This engine must meet the Tier 2 emission limits for non-road engines in 40 CFR 89.112. The limits for these Tier 2 engines with rating exceeding 560 kW are:

- 4.8 g/hphr for NO<sub>x</sub> and non-methane hydrocarbons (NMHC) combined;
- 2.6 g/hphr for CO; and
- 0.15 g/hphr for PM for 2013 or earlier model engines and 0.15 g/kWh for 2014 or later model years.

EUs 110 and 111 must meet the limits for emergency fine water pump engines with rating

exceeding 610 hp of model year 2008 and later in Table 4 of Subpart IIII. The limits for these engines are:

- 3.0 g/hphr for NO<sub>x</sub> and NMHC combined
- 2.6 g/hphr for CO; and
- 0.15 g/hphr for PM for 2013 or earlier model engines and 0.15 g/kWh for 2014 or later model years.

### **3.1.3. Composition of Wastes Burned in Incinerators**

To avoid classification as a medical waste incinerator, ExxonMobil requested the Department to limit the medical wastes content of the wastes burned in each incinerator to less 10 percent, averaged over a calendar quarter. Section 7 of the permit contains monitoring for the waste burned in the incinerators.

### **3.1.4. Other Requirements for Incinerators**

At the time the PSD permit application was submitted to the Department, the applicability of 40 CFR 60 Subpart CCCC requirements that were promulgated on March 21, 2011, was stayed. On January 9, 2012, the U.S. District Court for the District of Columbia vacated the Delay Notice that was published in the Federal Register on May 18, 2011. The Delay Notice had stayed the effective date of the requirements of the final changes to 40 CFR 60 Subpart CCCC that was promulgated on March 21, 2011. On February 7, 2012, EPA issued a No Action Assurance Letter for certain notification requirements under 40 CFR 60 Subpart CCCC. That No Action Assurance Letter did not address other applicable requirements and did not stay any notification requirement. EPA promulgated final changes to 40 CFR 60 Subpart CCCC on February 7, 2013, however the amendments to the rule don't take effect until August 7, 2013. As a result, Emission Units 11, 105, and 106 must meet the applicable requirements of 40 CFR 60 Subpart CCCC as promulgated on March 21, 2011. Section 7 of the permit contains these requirements.

EUs 246 and 247 are considered existing incinerators for NSPS applicability purposes because construction of the incinerators was commenced before May 20, 2011; therefore they are not subject to the emission requirements of 40 CFR 60 Subpart CCCC. Instead, these incinerators are subject to the emission limits that are developed consistent with the requirements of 40 CFR 60 Subpart DDDD for states with a currently effective State plan for existing commercial and industrial solid waste incineration (CISWI) units, approved by EPA. Alaska does not currently have an effective State plan approved by EPA. Instead, the temporary incinerators could be subject to the requirements of the Federal Implementation Plan (FIP) that EPA implements because a State plan has not been implemented. In this case, the FIP is found at 40 CFR 62, Subpart III, Federal Plan Requirements for CISWI Units that Commenced Construction on or before November 30, 1999. As indicated by the title of 40 CFR 62, Subpart III, this FIP has not yet been updated to include existing incinerators for which construction was commenced after November 30, 1999. As a result, 40 CFR 62 Subpart III is not applicable to the temporary incinerators.

### **3.1.5. NESHAP Standards for Boilers**

EPA promulgated final changes to 40 CFR 63 Subpart JJJJJ on February 1, 2013. The EPA amended 40 CFR 63 Subpart JJJJJ by adding temporary boilers to the list of boilers not subject

to the subpart. The EPA also established separate requirements for two subcategories of boilers; seasonally operated boilers and small oil-fired boilers.

Seasonally operated boilers are required to complete a tune-up every 5 years, instead of on a biennial basis. Existing seasonal boilers are required to complete the initial tune up by March 21, 2014, and a subsequent tune-up every 5 years after the initial tune-up. New and reconstructed seasonal boilers are not required to complete an initial tune-up, but are required to complete a tune-up every 5 years (no more than 61 months) after the initial startup of the new or reconstructed boiler. Records of the days of operation per year must be maintained.

Seasonal boiler means a boiler that undergoes a shutdown for a period of at least 7 consecutive months (or 210 consecutive days) each 12-month period due to seasonal conditions, except for periodic testing. Periodic testing shall not exceed a combined total of 15 days during the 7-month shutdown. This definition only applies to boilers that would otherwise be included in the biomass subcategory or the oil subcategory.

Small oil-fired boilers have a heat input capacity of equal to or less than 5 MMBtu/hr and are required to complete a tune-up every 5 years instead of on a biennial basis as is required for most larger oil-fired boilers. Existing oil-fired boilers with a heat input capacity of equal to or less than 5 MMBtu/hr are required to complete the initial tune-up by March 21, 2014, and a subsequent tune-up every 5 years (61 months) after the initial tune-up. New and reconstructed oil-fired boilers with a heat input capacity of equal to or less than 5 MMBtu/hr are not required to complete an initial tune-up, but are required to complete a tune-up every 5 years (61 months) after the initial startup of the new or reconstructed boiler.

Emission Units 1 (Drill Rig Boiler No.1: 4.2 MMBtu/hr) and 16 (Bulk Tank Storage Area Boiler No.1: 4.97 MMBtu/hr) are small oil-fired units under 40 CFR 63 Subpart JJJJJ.

### **3.1.6. NSPS Standards for Crude Oil and Natural Gas Production**

The permit also contains 40 CFR Subpart OOOO requirements for natural gas processing plants that are included at the Permittee's request. The subpart rules became effective on October 15, 2012 for Crude Oil and Natural Gas Production, Transmission and Distribution facilities. Under this subpart the Permittee must meet certain monitoring, recordkeeping and reporting requirements.

## **3.2. State Emission Standards**

40 CFR 52.21(j)(1) requires the stationary source to meet each applicable limitation under the Alaska State Implementation Plan.

### **3.2.1. 18 AAC 50.050(a): Incinerator Visible Emission (VE) Standards**

Section 3 of the permit carried over the initial compliance demonstration requirement from AQ1201CPT01 with the VE standard using 40 CFR 60, Appendix A, Reference Method 9.

### **3.2.2. 18 AAC 50.050(b): Incinerator PM Emission Standards**

The incinerators at the stationary source are not subject to the standard because they are rated at less than 1,000 lb/hr.

### **3.2.3. 18 AAC 50.055(c): Sulfur Compound Emissions Standards**

Industrial process equipment and fuel-burning equipment at the stationary source must comply with 18 AAC 50.055(c), the state sulfur compounds emissions standard. Sulfur compound emissions, expressed as SO<sub>2</sub>, from an industrial process or from fuel-burning equipment may not exceed 500 ppmv averaged over a period of three hours. The diesel equipment will burn ULSD and will meet the standard. The fuel gas burned at the facility will contain no more than 300 ppmv of H<sub>2</sub>S. EUs burning such fuel gas will meet the standard. Section 6 of the permit contains monitoring requirements for fuel sulfur content and H<sub>2</sub>S content of the fuel gas.

### **3.3. ORLs under 18 AAC 50.508(5) to Avoid PSD for SO<sub>2</sub>**

The applicant requested ORLs to avoid minor permitting for SO<sub>2</sub>. These limits include:

- The hydrogen sulfide (H<sub>2</sub>S) content of the fuel gas burned in the turbine not to exceed 125 parts per million by volume (ppmv);
- The H<sub>2</sub>S content of the fuel gas burned in the high pressure flare not to exceed 125 ppmv; except for pilot and purge;
- The H<sub>2</sub>S content of the fuel gas burned in the low pressure flare and in the high pressure flare for pilot and purge not to exceed 300 ppmv; and
- All diesel-fired combustion units must burn ULSD.

These limits will keep the annual SO<sub>2</sub> emissions to below 40 tons. The Department has included periodic monitoring. The Department has included monitoring and recordkeeping requirements to comply with the ULSD requirement. For compliance with the fuel gas H<sub>2</sub>S limit the Department has required that the applicant measure the fuel gas content and report the H<sub>2</sub>S content periodically. These requirements are included in Section 6 of the permit.

### **3.4. Revisions under 18 AAC 50.508(6):**

The Department made several other requested revisions to Permit AQ1201CPT01. These are listed below:

- The applicant requested several changes to the ambient limits. These changes are listed in the Conclusion Section of the Modeling Memorandum in Appendix C of this TAR. The revised conditions and the necessary MR&R are in Section 4 of this permit.
- The applicant also requested the addition of two incinerators 246 and 247. EU 246 will remain onsite after the 24 month construction period has expired. Therefore, the unit was part of the BACT analysis, the ambient and increment analysis. EU 247 will be removed at the end of the construction period. As such only EU 246 is included in the list of units subject to BACT limits.

- The Department noted that Permit AQ1201CPT01 did not contain the necessary MR&R to demonstrate compliance with the NO<sub>x</sub> and CO BACT limits for the turbines. The MR&R that cross referenced the NSPS Subpart KKKK MR&R was not adequate for compliance with the BACT limits for NO<sub>x</sub>, CO, PM-10 and PM-2.5. The Department took the opportunity to correct the error in this permit action. Permit AQ1021CPT02 contains winter and summer source testing in and out of SoLoNO<sub>x</sub> for each type of fuel to comply with the NO<sub>x</sub> and CO limits in and out of SoLoNO<sub>x</sub> and a source testing requirement to comply with the PM-10 and PM-2.5 BACT limits. Section 5 of the preliminary permit contains the turbine BACT limits and associated MR&R requirements that ensure the combustion turbines comply with the BACT limits.
- Deleted the load limits specified with the BACT limits because the operating modes (in or out of SoLoNO<sub>x</sub> mode) are all that is needed. The Department added a footnote to define that SoLoNO<sub>x</sub> mode is when turbines 101 and 102 operates at or below 25 percent load and Turbines 103 and 104 operates at or below 50 percent load. The Department also included an averaging period for each of the BACT limits to be one hour. An averaging period is needed to comply with the source test method used for compliance with the BACT limits. The Department also added the outlet temperature of the catalytic bed as requested by the Applicant.
- The applicant requested a revision to the combined annual operating limit of EUs 103 and 104 when burning ULSD in SoLoNO<sub>x</sub> mode from 2,000 hours to 4,000 hours combined. The Department denied the request because that limit was developed and used in the 2012 BACT evaluation. The Permittee must demonstrate that this limit is unattainable in order to revise the established BACT limit.
- The applicant also requested a revision to the combined annual operating limit of 500 hours for EUs 101 through 104 out of SoLoNO<sub>x</sub> mode. The change limits operating EUs 101 through 104 out of SoLoNO<sub>x</sub> mode to 250 hours when firing fuel gas and limits operating EUs 101 through 104 to 250 hours while firing ULSD. The Department revised the BACT limits as requested since the requested change is more stringent.

### **3.5. Standard Permit Conditions**

As required under 18 AAC 50.345 and 18 AAC 50.346, the Department must include the standard permit conditions (b) through (o). Section 10 of the permit lists these standard permit conditions.

## **4. PERMIT ADMINISTRATION**

The stationary source has the potential to emit more than 100 tpy of one or more pollutants. Therefore, a timely Title V application for the stationary source is due no later than 12 months after the stationary source commences operation. The Department is interpreting ‘commences operation’ as ‘starting to operate any of the production EUs except for the two incinerators and the airstrip generator, EUs 105, 106, and 114’. These emission units are not part of the production equipment. The Department based its decision on a reasonable interpretation of 40 CFR 71.5(a)(1)(ii).

APPENDIX A: EMISSIONS CALCULATIONS

Table A-1 presents details of the EUs, their characteristics, and emissions during the Operations and Drilling (O&D) Phase. The Department obtained the emissions from Appendix B-1 of the application. The Department verified the PTE with emission factors given in Tables B-1 through B-7 of Appendix B-1 of the application and the EU characteristics in Table A-1.

Table A-1: Detailed Permanent EU Inventory and Tons Emitted per Year

EU	Description of Emission Units	Rating	Hr/yr	NOx		CO		PM-2.5		PM-10		VOC		SO <sub>2</sub>	CO <sub>2e</sub>		
				EF	TPY	EF	TPY	EF	TPY			EF	TPY	TPY	TPY		
<b>Production</b>																	
101	Gas fired Turbine	7,520 kW	8,760	5.01 lb/hr	22.30	0.53 lb/hr	2.32	0.0066	2.50	0.0066	2.52	0.78 lb/hr	3.42	7.0	44,632		
102	Gas fired Turbine	7,520 kW	8,510		21.70		2.26		2.50		2.52						
103	Dual-fuel Turbine firing Fuel Gas	7,520 kW	6,760	8.48 lb/hr	28.66	1.03 lb/hr	4.50	0.0066	1.90	0.0066	1.94	0.93 lb/hr	3.14	7.0	34,442		
104	Dual-fired Turbine firing Fuel Gas	7,520 kW	6,510		27.60		4.40		1.90		1.94						
103	Dual-fired Turbine firing ULSD	7,520 kW	2,000	31.6 lb/hr	31.6	1.04 lb/hr	1.04	0.012	1.00	0.012	1.00	0.30 lb/hr	12.20	0	13,500		
104	Dual-fired Turbine firing ULSD	7,520 kW							1.00		1.00			0	13,500		
101-4	Turbines in Non-SoloNO <sub>x</sub> Mode	60 MMBtu/hr	250	26.40 lb/hr	4.50	129 lb/hr	16.13	0.18	0.18	0.18	0.18	15.45 lb/hr	1.93	0	1,800		
105	Waste Incinerator	220 lb/hr	7,446	170 ppm	1.23	13 ppm	0.10	270	mg/dscm	3.46	270	mg/dscm	3.46	3 lb/ton	1.23	0.01	459
106	Waste Incinerator	220 lb/hr	7,446														
107	Standby Camp Generator Eng 1	2,695 hp	100	4.8 g/hphr	1.43	3.5 g/kWh	0.78	0.15 g/hphr	0.04	0.2 g/kWh	0.04	0.000705	lb/bhphr	0.13	0	135	
108	Standby Camp Generator Eng 2	2,695 hp	100		1.42		0.78		0.04		0.04			0.13	0	135	
109	Standby Camp Generator Eng 3	2,695 hp	100		1.42		0.78		0.04		0.04			0.13	0	135	
110	Fire Water Mist Pump Eng No. 1	610 hp	100	3.0 g/hphr	0.24	2.6 g/hphr	0.20	0.15 g/bhphr	0.01	0.15	0.00	1.1 g/hphr	0.07	0	56		
111	Fire Water Mist Pump Eng No. 2	610 hp	100		0.24		0.01		0.01		0.00		0.07	0	56		
112	High Pressure Flare – Pilot / Purge	35 MMscf/yr	8,760	0.068	1.21	0.37	6.60	0.0264	0.47	0.0264	0.47	0.14	1.20	0.7	1,113		
113	Low Pressure Flare – Pilot / Purge	20 MMscf/yr	8,760	lb/MMBtu	0.69	lb/MMBtu	3.77	lb/MMBtu	0.27	lb/MMBtu	0.27	lb/MMBtu	1.43	0.5	1,203		
114	Standby Airstrip Generator Engine	490 hp	100	3.0 g/hphr	0.02	2.6 g/hphr	0.14	0.15 g/hphr	0.01	0.02 g/kWh	0.00	0.19 g/kWh	0.01	0	27		
246	Waste Incinerator	150 lb/hr	8,760	3 lb/ton	0.99	10 lb/ton	3.29	7 lb/ton	2.30	7 lb/ton	2.30	3 lb/ton	0.99	0.82125	661		
	<b>All Production Emission Units</b>				<b>145.25</b>		<b>47.08</b>		<b>17.64</b>		<b>17.72</b>		<b>32.42</b>	<b>30.0</b>	<b>190,928</b>		
<b>ULSD-fired Drilling, Workover, and Miscellaneous Support</b>																	
1	Drill Rig Boiler #1, KLG-42	4.2 MMBtu/hr	8,760	4 lb per 1,000 gal	0.53	5 lb per 1,000 gal	0.67	0.25 lb per 1,000 gal	0.03	1 lb per 1,000 gal	0.13	0.252 lb per 1,000 gal	0.03	0.03	2,967		
2	Drill Rig Boiler #2, KLG-63	6.3 MMBtu/hr	8,760		0.80		1.00		0.05		0.20		0.05	0.04	4,450		
3	Iron Fireman C-240, F-4.2 Tioga 1	4.2 MMBtu/hr	8,760		0.53		0.67		0.03		0.13		0.03	0.03	2,967		
4	Iron Fireman C-240, F-4.2 Tioga 2	4.2 MMBtu/hr	8,760		0.53		0.67		0.03		0.13		0.03	0.03	2,967		
5	Drill Rig Boiler #1, ML-63P	6.3 MMBtu/hr	8,760		0.80		1.00		0.05		0.20		0.05	0.04	4,450		
6	Drill Rig Boiler #2, ML-63P	6.3 MMBtu/hr	8,760	0.80	1.00	0.05	0.20	0.05	0.04	4,450							
7	Reznor OH190 Drill Rig Heater 1	0.23 MMBtu/hr	0	0.03	0.03	0.00	0.01	0.00	0.002	163							
8	Reznor OH190 Drill Rig Heater 2	0.23 MMBtu/hr	0	0.03	0.03	0.00	0.01	0.00	0.002	163							
11	Consumat C32P Waste Incinerator	130 lb/hr	7,439	170 ppm	0.80	13 ppm	0.10	270	0.30	270	0.30	3 lb/ton	0.90	0.01	573		

EU	Description of Emission Units	Rating	Hr/yr	NOx		CO		PM-2.5		PM-10		VOC		SO <sub>2</sub>	CO <sub>2e</sub>
				EF	TPY	EF	TPY	EF	TPY	mg/dscm	mg/dscm	EF	TPY	TPY	TPY
16	Well-McBlain 1688 Boiler #1	5.0 MMBtu/hr	8,760	4 lb per	0.63	5 lb per	0.79	0.25 lb per	0.04	1 lb per	0.16	0.252 lb per	0.04	0.03	3,511
17	Well-McBlain 1688 Boiler #2	5.3 MMBtu/hr	8,760	1,000 gal	0.67	1,000 gal	0.79	1,000 gal	0.04	1,000 gal	0.16	1,000 gal	0.04	0.04	3,758
18	Perkins 2306-E14 TAG Gen #1	375 kW	8,760		1.45		12.67		0.07		0.07		0.69	0.02	2,540
19	Perkins 2306-E14 TAG Gen #2	375 kW	8,760	0.40 g/kWh	1.45	3.5 g/kWh	12.67	0.02 g/kWh	0.07	0.02 g/kWh	0.07	0.19 g/kWh	0.69	0.02	2,540
20	MMD Power Pro 150 Gen #3	190 hp	8,760		0.55		4.79		0.03		0.03		0.26	0.01	860
21	MMD Power Pro 150 Gen #4	190 hp	8,760	0.40 g/kWh	0.55	3.5 g/kWh	4.79	0.02 g/kWh	0.03	0.02 g/kWh	0.03	0.19 g/kWh	0.26	0.01	860
22	Therm Dynamics Cat C6-6 Eng #1	165 hp	8,760		0.48		5.94		0.02		0.02		0.23	0.01	850
23	Therm Dynamics Cat C6-6 Eng #2	165 hp	8,760	0.40 g/kWh	0.48	5 g/kWh	5.94	0.02 g/kWh	0.02	0.02 g/kWh	0.02	0.19 g/kWh	0.23	0.01	850
25	ES 700 Portable Heater	0.7 MMBtu/hr	8,760		0.09		0.11		0.01		0.02		0.01	0	505
26	ES 700 Portable Heater	0.7 MMBtu/hr	8,760	4 lb per	0.09	5 lb per	0.11	0.25 lb per	0.01	1 lb per	0.02	0.252 lb per	0.01	0	505
27	ES 700 Portable Heater	0.7 MMBtu/hr	8,760	1,000 gal	0.09	1,000 gal	0.11	1,000 gal	0.01	1,000 gal	0.02	1,000 gal	0.01	0	505
28	Heliport Engine	35.9 hp	8,760	4.7 g/kWh	1.22	5.5 g/kWh	1.42	0.03 g/kWh	0.01	0.03 g/kWh	0.01	0.00247 lb/hphr	0.00	0	142
30	Misc Portable Boiler and Heater 1	2.8 MMBtu/hr	8,760		0.36		0.44		0.02		0.09		0.02	0.02	1,985
31	Misc Portable Boiler and Heater 2	2.8 MMBtu/hr	8,760		0.36		0.44		0.02		0.09		0.02	0.02	1,985
32	Misc Portable Boiler and Heater 3	2.8 MMBtu/hr	8,760	4 lb per	0.36	5 lb per	0.44	0.25 lb per	0.02	1 lb per	0.09	0.252 lb per	0.02	0.02	1,985
33	Misc Portable Boiler and Heater 4	2.8 MMBtu/hr	8,760	1,000 gal	0.36	1,000 gal	0.44	1,000 gal	0.02	1,000 gal	0.09	1,000 gal	0.02	0.02	1,985
34	Misc Portable Boiler and Heater 5	2.8 MMBtu/hr	8,760		0.36		0.44		0.02		0.09		0.02	0.02	1,985
35	Misc Portable Boiler and Heater 6	2.8 MMBtu/hr	8,760		0.36		0.44		0.02		0.09		0.02	0.02	1,985
	<b>Drilling, Workover, &amp; Misc EUs</b>				<b>14.72</b>		<b>57.99</b>		<b>1.04</b>		<b>2.48</b>		<b>3.73</b>	<b>0.49</b>	<b>52,486</b>
	<b>Total for all Permanent EUs</b>				<b>159.97</b>		<b>105.07</b>		<b>18.68</b>		<b>20.21</b>		<b>36.15</b>	<b>30.53</b>	<b>243,414</b>

Table Notes:

Emission factors for turbines firing in Non-SoLoNOx mode taken from Table B-7a through B-9a of application (50% or 25% load, whichever gives higher EF). Each turbine has a catalytic oxidizer to reduce the vendor-provided CO emission factors by 90% in SoLoNOx mode and 85% out of SoLoNOx mode. The catalytic oxidizers control 50 percent of VOC emissions while firing on ULSD in SoLoNOx mode, and 5 percent of VOC emissions in non-SoLoNOx mode. VOC emissions are assumed to be 100 percent when firing fuel gas and 20 percent while firing ULSD.

TPY SO<sub>2</sub> estimated by mass balance  
 SO<sub>2</sub> Emission Factor = 21.1 lb/MMscf  
 Fuel Gas Heat Content: 1,020 Btu/scf  
 Fuel Gas H<sub>2</sub>S Content: 125 ppmv  
 ULSD Heat Content: 137,000 Btu/gal  
 CO<sub>2e</sub> Emission Factor = ((CO<sub>2</sub> EF) + (21 × CH<sub>4</sub> EF) + (310 × N<sub>2</sub>O EF))  
 CO<sub>2</sub> EF taken from 40 CFR 98, Table C-1  
 CH<sub>4</sub> and N<sub>2</sub>O EFs taken from 40 CFR 98, Table C-2

## APPENDIX B: BACT ANALYSIS PM-10

### 1.0 Introduction

The Point Thomson Facility triggered PSD requirements for nitrogen oxides (NO<sub>x</sub>), carbon monoxide (CO), particulate matter with an aerodynamic diameter not exceeding a nominal 10 micrometers (PM-10), particulate matter with aerodynamic diameter less than or equal to a nominal 2.5 micrometers (PM-2.5), and greenhouse gases (GHG). The Department reviewed Exxon Mobil's BACT analysis for the Point Thomson project and made BACT determinations for NO<sub>x</sub>, CO, and PM-2.5 in Permit AQ1201CPT01. The BACT analysis for these pollutants can be found in the TAR for Permit AQ1201CPT01.

This appendix reviews ExxonMobil's BACT analysis for PM-10 for its technical accuracy and adherence to accepted engineering cost estimation practices.

### 2.0 BACT Evaluation

A BACT analysis is an evaluation of all available control options for equipment emitting the triggered pollutants and a process for selecting the best option based on feasibility, economics, energy, and other impacts. 40 CFR 52.21(b)(12) defines BACT as a site-specific determination on a case-by-case basis. The Department's goal is to identify BACT for the permanent EUs at Point Thomson Facility that emit PM-10, establish emission limits which represent BACT, and assess the level of monitoring, recordkeeping, and reporting (MR&Rs) necessary to ensure ExxonMobil applies BACT for the EUs. The Department based the BACT review on the five-step top-down approach set forth in Federal Register Volume 61, Number 142, July 23, 1996 (Environmental Protection Agency). Table B-1 presents the EUs subject to BACT review.

**Table B-1: EUs Subject to BACT Review**

<b>EU ID</b>	<b>Description of EU</b>
101	Fuel Gas-Fired Solar 70 Taurus Turbine
102	Fuel Gas-Fired Solar 70 Taurus Turbine
103	Dual Fuel Solar 70 Taurus Turbine firing fuel gas
	Dual Fuel Solar 70 Taurus Turbine firing ULSD
104	Dual Fuel Solar 70 Taurus Turbine firing fuel gas
	Dual Fuel Solar 70 Taurus Turbine firing ULSD
11, 105 – 106, 246	Waste Incinerators
107 - 109	Standby Camp Generators
110 - 111	Fine Water Mist Pump Engines
37, 112, and 113	Well Testing Flare, High Pressure Flare, and Low Pressure Flare
114	Standby Airstrip Generator
18 through 21	Perkin Generators, MMD Generators
22 and 23	Caterpillar Engines
28	Heliport Engine
1 through 6, 16, 17, 36	Boilers
7, 8, 25-27, 30-35	Heaters

***Five-Step BACT Determinations***

The following sections explain the steps used to determine BACT for PM-10 for the applicable equipment.

**Step 1 Identify All Potentially Available Control Options**

The Department identifies all available control options for the EUs and the pollutant under consideration. This includes technologies used throughout the world or emission reductions through the application of available control techniques, changes in process design, and/or operational limitations. To assist in identifying available controls, the Department reviews available controls listed on the Reasonably Available Control Technology (RACT), BACT, and Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC). The RBLC is a United States Environmental Protection Agency (EPA) database where permitting agencies nationwide post imposed BACT for PSD sources. It is usually the first stop for BACT research. In addition to the RBLC search, the Department used several search engines to look for emerging and tried technologies used to control PM emissions from equipment similar to those listed in Table B-1.

**Step 2 Eliminate Technically Infeasible Control Options:**

The Department evaluates the technical feasibility of each control option based on source specific factors in relation to each EU subject to BACT. Based on sound documentation and demonstration, the Department eliminates control options deemed technically infeasible due to physical, chemical, and engineering difficulties.

**Step 3 Rank Remaining Control Technologies by Control Effectiveness**

The Department ranks the remaining control options in order of control effectiveness with the most effective at the top.

#### **Step 4 Evaluate the Most Effective Controls and Document the Results as Necessary**

The Department reviews the detailed information in the permit application about the control efficiency, emission rate, emission reduction, cost, environmental, and energy impacts for each option to decide the final level of control. The applicant must present an objective evaluation of both the beneficial and adverse energy, environmental, and economic impacts. An applicant proposing to use the most effective option does not need to provide the detailed information for the less effective options. If cost is not an issue, a cost analysis is not required.

Cost effectiveness for a control option is defined as the total net annualized cost of control divided by the tons of pollutant removed per year. Annualized cost includes annualized equipment purchase, erection, electrical, piping, insulation, painting, site preparation, buildings, supervision, transportation, operation, maintenance, replacement parts, overhead, raw materials, utilities, engineering, start-up costs, financing costs, and other contingencies related to the control option. Section 3 presents the Department's BACT Determinations for PM-10.

#### **Step 5 Select BACT**

The Department selects the most effective control option not eliminated in Step 4 as BACT for the pollutant and EU under review. The Department lists the final BACT requirements determined for each EU in this step. A project may achieve emission reductions through the application of available technologies, changes in process design, and/or operational limitations. The Department reviewed Exxon Mobil's BACT analysis for the Point Thomson Facility and made BACT determinations for PM-10 for various EUs based on the information submitted by Exxon Mobil in their application, information from vendors, suppliers, sub-contractors, RBLC, and an exhaustive internet search.

### **3.0 BACT Determination for PM-10**

Electrostatic precipitators (ESPs) are usually used for controlling large particulates. ESPs are not suitable for controlling fine PM emissions from combustion. Fabric filters (baghouses) are not suitable for controlling particulates from combustion equipment because of fire hazards. The RBLC database identified two BACT determinations for diesel turbines. They were to 'Limit Operation Hours' and 'Good Operation Practices'. The only BACT determination for incinerators in the RBLC was 'No Control'. The RBLC database and internet research showed that an overwhelming majority of PM BACT determinations were 'No Control' or 'Good Combustion and Operation Practices'.

**Table B-2: PM BACT Determinations in RBLC for July 2001-February 12, 2012**

Description of NOx BACT	Fuel Gas Turbines	Internal Combustion Engines		Diesel Heaters & Boilers	Flares	Biomass Boilers
		hp > 500	hp < 500			
Good Combustion Practices, None	29	47	46	7	10	
Limit Fuel Use / Hours	1	3	6			
Scrubber		0	0	2		
Limit Operating Hours		9	5	1		
Turbocharger	1	2	1			
Engine Design		12	11			
Timing Retard		2	1			
NSPS Subpart IIII		6	0			
Clean Fuel	7	17	9	1		
Preventive Maintenance		5	3			
Combustion Control		4	2		1	
Lean Burn	1		1			
Electrostatic Precipitator						2
<b>Total</b>	<b>39</b>	<b>107</b>	<b>85</b>	<b>11</b>	<b>11</b>	<b>2</b>

### 3.1 Identification of PM Control Technologies

PM control technologies include ESPs, fabric filters, and scrubbing. These controls and their limitations are described below:

#### (a) ESPs

Since the equipment at the Point Thomson Facility will burn fuel gas and ULSD, the PM emissions produced would be too fine for ESPs to collect efficiently. ESPs are installed as stand-alone collectors or after a primary PM control system. ESPs collect PM by introducing a strong electrical charge in the flue gas. The charged particles collect on large plates which have an opposite charge applied to them to attract the entrained charged particles. Rapping the plates causes the agglomerated particles to fall into hoppers.

#### (b) Fabric Filters (Baghouses)

Fabric filters are typically installed downstream of a quench tower or spray dryer. The lowered temperature and increased moisture protect the filter bags from hot embers, thus preventing industrial fires. Fabric filters remove PM from a gas stream by passing the gas stream through a porous fabric. The PM particles form a porous cake on the surface of the fabric. It is the PM porous cake that filters more PM particles out. Fabric filters are of two types – reverse-air and pulse-jet fabric filters. Compared with reverse-air filter, pulse-jet fabric filters have a lower capital cost, shorter life, higher pressure drop, higher PM emissions, smaller footprint, and have a higher total cost than reverse-air filters.

#### (c) Wet Scrubbers

Wet scrubbers are typically downstream of an ESP as a PM-removal polishing stage. A venturi scrubber followed by a packed or tray tower is commonly used. Wet scrubbers simultaneously remove acid gases.

### 3.2 PM-10 BACT for the Turbines

There are no NSPS PM standards for turbines. AP-42 Table 3.1-2a provides the closest emission factors for these turbines. Based on the BACT determinations in the RBLC, internet research, and the BACT proposed by ExxonMobil, the Department determined PM-10 BACT to be the same as PM-2.5 BACT, for the turbines as good operation and combustion practices, emitting no more than the average rates given in AP-42 and listed in Table B-3.

**Table B-3: PM-2.5 BACT Limits for Solar Taurus 70 Turbines**

EU ID	Description of Turbine	lb/MMBtu	Source of BACT
101, 102	Gas-fired Turbines	0.0066	AP-42, Table 3.1-2a
103, 104	Dual fuel, burning fuel gas	0.0066	
	Dual fuel, burning ULSD	0.012	

### 3.3 PM-10 BACT for the Diesel Engines

Based on the BACT determinations in the RBLC, internet research, and BACT proposed by ExxonMobil, the Department determined PM-10 BACT to be the same as PM-2.5 BACT, for the engines as shown in Table B-4. The BACT limits are the NSPS standards.

**Table B-4: PM BACT Limits for Diesel Reciprocating Engines**

EU ID	Rating	Description Engine	BACT Limit	Reference
107 – 109	1,750 kW	Emergency camp generators	0.20 g/kWh	Tier 2, Table 1, 40 CFR 89.112
110 and 111	575 hp	Fine water mist pumps	0.15 g/hphr	40 CFR 60, Subpart IIII, Table 4
114	350 kW	Emergency airstrip generator	0.2 g/kWh	40 CFR 60.4216(c); Table 1, 40 CFR 89.112
18 and 19	375 kW	Bulk Tank Perkins Generators	0.2 g/kWh	
20 and 21	190 hp	Bulk Tank Area Generators	0.2 g/kWh	
22 and 23	165 hp	Therm Dynamics CAT Engines	0.3 g/kWh	
28	36 hp	Heliport Engine	0.6 g/kWh	

Table Notes:

The BACT limits for EUs 18 through 28 are for 2013 model years or earlier. The limits for 2014 model year or later are 0.15 g/kWh.

### 3.4 PM-10 BACT for Boilers and Heaters

The RBLC did not contain determinations besides ‘No Control’ and ‘Good Practices’. There are no proven technologies to control PM-10 for boiler and heaters per the Department’s independent search on the internet. The total PM factor for diesel-fired low NOx burner boilers in AP-42 Table 1.3-1 is 3.4 lb/1,000 gal. Therefore, the Department agrees with the applicant that AP-42, Table 1.3-6 emission rates shown in Table B-5, combined with good operational practice is BACT for PM-10. The emission rate for PM-2.5 is included here for clarity.

**Table B-5: PM-10 BACT Limits for Diesel Boilers and Heaters**

EU ID	Description	BACT Limit (lb/gal)
1 and 2	Drill Rig Boilers (KL)	PM-10 = 0.001 PM-2.5 = 0.00025
3 and 4	Iron Fireman Boilers C-240	
5 and 6	Drill Rig Boilers, ML-63P	
7 and 8	Rezno Drill Rig Heater	
16, 17, 36	Storage Boilers, Well Testing Boiler	
25 through 27	ES700 Portable Heater	
30 through 35	Miscellaneous Portable Heaters	

**3.5 PM-10 BACT for Incinerators**

The Department performed an internet research for control of PM-10 emissions from incinerators. The RBLC did not contain determinations besides ‘No Control’ and ‘Good Practices’. Currently there is no NSPS for incinerators. The applicant proposed an emission limit of 230 milligrams per dry standard cubic meters (mg/dscm), which is the small, remote incinerator emission limit from 40 CFR 60 Subpart CCCC Table 8. The Department accepted the proposed emission limit. Based on the BACT determinations in the RBLC, internet research, the Department determined PM-10 BACT for the incinerators is as presented in Table B-6.

**Table B-6: PM BACT Limits for Waste Incinerators**

EU ID	Description of Waste Incinerator	BACT Limit (mg/dscm)
11	Consumat C32P Camp Incinerator	270
105 and 106	Dual Fuel (Fuel Gas, ULSD) Incinerators	270
246	Temporary Incinerator No. 1	270

**3.6 PM-10 BACT for Flares**

The RBLC did not contain determinations besides ‘No Control’ and ‘Good Practices’. The RBLC did not contain any emission limit determination. Based on the BACT determinations in the RBLC, internet research, and the BACT proposed by ExxonMobil in Table D-17 of their application, the Department determined PM BACT for the flares as presented in Table B-7.

**Table B-7: PM BACT Limits for Flares**

EU ID	Description of Flare	BACT Limit (lb/MMBtu)
37	Well Testing Flare	0.0264
112	High Pressure Flare	0.0264
113	Low Pressure Flare	0.0264

## APPENDIX C: MODELING MEMORANDUM

# MEMORANDUM

**State of Alaska**  
**Department of Environmental Conservation**  
**Division of Air Quality**

TO: File

DATE: 18 April, 2013

THRU: Alan Schuler, PE  
Engineer, DEC  
Air Permits Program

FILE NO: AQ1201CPT02

PHONE: (907) 465-5324  
FAX: (907) 465-5129

FROM: James Julian Renovatio, EIT  
Engineering Assistant, DEC  
Air Permits Program

SUBJECT: Review of ExxonMobil's Ambient  
Analysis for the Revision to the PSD  
Construction Permit at Point Thompson

This memorandum summarizes the Department's findings regarding the ambient assessment submitted by the ExxonMobil Corporation (ExxonMobil) for their Application to Amend the Prevention of Significant Deterioration (PSD) Air Quality Construction Permit at Point Thompson. ExxonMobil submitted this assessment in support of their 2 November, 2012 PSD permit application (AQ1201CPT02). The pollutants subject to PSD review for this application are nitrogen dioxide (NO<sub>2</sub>), ozone<sup>2</sup> (O<sub>3</sub>), carbon monoxide (CO), coarse particulate matter (PM-10), and fine particulate matter (PM-2.5).<sup>3</sup> Sulfur dioxide (SO<sub>2</sub>) is also subject to review under the Department's minor permit provisions for portable oil and gas operations.

The Department finds that the PSD aspects of ExxonMobil's application and supplemental information adequately complies with the source impact analysis required under 40 CFR 52.21(k), the pre-construction monitoring analysis required under 40 CFR 52.21(m)(1), and the additional impact analysis required under 40 CFR 52.21(o). ExxonMobil's ambient air analysis adequately demonstrates that operating the Point Thompson emissions units (EUs) within the restrictions listed in this memorandum will not cause or contribute to a violation of the annual or 1-hour NO<sub>2</sub>, 8-hour or 1-hour CO, 24-hour PM-10, and annual or 24-hour PM-2.5 Alaska Ambient Air Quality Standards (AAAQS) provided in 18 AAC 50.010. Additionally, their analysis adequately demonstrates that operating the Point Thompson EUs within the restrictions listed in this memorandum will not cause or contribute to a violation of the annual NO<sub>2</sub>, annual or 24-hour PM-10, and annual or 24-hour PM-2.5 maximum allowable increases (increments) listed in 18 AAC 50.020. This memorandum supersedes the Department's 4 June, 2012 memorandum regarding ExxonMobil's previous ambient assessment for Point Thomson, submitted in support of Construction Permit AQ1201CPT01.

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<sup>2</sup> Ozone is triggered indirectly through the PSD-level precursor emissions of NO<sub>2</sub> per 40 CFR 52.21(i)(5)(i).

<sup>3</sup> Greenhouse gases (GHG) are also subject PSD review for project emissions in excess of 75,000 tons-per-year of carbon dioxide equivalent (CO<sub>2</sub>e), however, modeling is not required since there is no CO<sub>2</sub>e ambient standard.

## BACKGROUND

### Project Location and Area Classification

Point Thomson is a new PSD Major stationary source that would be located along the Beaufort Sea, just west of the Arctic National Wildlife Refuge (ANWR)<sup>4</sup>. The area is currently unclassified in regard to compliance with the NO<sub>2</sub>, O<sub>3</sub>, CO, PM-10, and PM-2.5 AAAQS. For purposes of increment compliance, Point Thomson is located within a Class II area of the Northern Intrastate Air Quality Control Region. The nearest Class I area, Denali National Park, is located approximately 700 kilometers (km) to the south.

### Source and Project Description

ExxonMobil intends to construct and operate a gas cycling operation at the Point Thompson field as detailed in the superseded 4 June, 2012 modeling memorandum for Construction Permit AQ1201CPT01. The EU inventory for this project consists of both permanent and temporary units. The total inventory includes two gas-fired turbines, two dual-fuel fired turbines, nine reciprocating engines rated above 1,000 horsepower (hp) fired on ultra low sulfur diesel (ULSD), five waste incinerators, and two flares; multiple smaller ULSD-fired reciprocating engines, ULSD-fired heaters, and other units associated with drilling, work-over and miscellaneous support. The proposed emissions trigger PSD review for GHG, NO<sub>2</sub>, O<sub>3</sub>, CO, PM-10, and PM-2.5. The project is also classified under 18 AAC 50.502(c)(2) for portable oil and gas operations and 18 AAC 50.508(5) for owner requested limits (ORL) to avoid the PSD review of SO<sub>2</sub>.

### Ambient Demonstration Requirements

In accordance with 18 AAC 50.306, PSD applicants must essentially comply with the federal PSD requirements in 40 CFR 52.21. Except as noted in 40 CFR 52.21(i), the ambient requirements include:

- A Source Impact Analysis, e.g. an ambient modeling analysis, for the PSD-triggered pollutants with an associated ambient air quality standard or increment per 40 CFR 52.21(k);
- An Air Quality Analysis, i.e. pre-construction monitoring data, for the PSD-triggered pollutants with an associated ambient air quality standard or increment per 40 CFR 52.21(m);
- An Additional Impact Analyses per 40 CFR 52.21(o); and
- A Class I Impact Analysis, for sources that may affect a Class I area, per 40 CFR 52.21(p).

The nearest Class I area to Point Thomson is too distant to warrant a Class I impact analysis; see the *Additional Impact Analyses* section for detail. Therefore, ExxonMobil is not required to provide a Class I impact analysis for the Point Thomson project.

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<sup>4</sup> ExxonMobil previously conducted portable oil and gas drilling operations at Point Thomson under mechanisms that include minor permit AQ1201MSS01 and owner requested limit (ORL) AQ1201ORL01. However, these mechanisms to operate have since been rescinded at ExxonMobil's request.

### **Project Submittal**

ExxonMobil submitted the permit application to the Department on 2 November, 2012. SLR International Corporation (SLR) prepared the PSD application, including the ambient analysis, on their behalf. ExxonMobil provided five supplements to their ambient analysis in response to multiple Department information requests. These supplements were received by e-mail on: 17 December, 2012; 16 January, 2013; 15 March, 2013; 1 April, 2013; and 4 April, 2013. Each supplement typically addressed Department concerns regarding the proposed approach to protect the various increments and AAAQS. As such, each supplement resulted in modifications of the EU inventory and operational assumptions, thus superseding the previous submission.

ExxonMobil and the Department inadvertently overlooked the project's minor permit classification for portable oil and gas operations under 18 AAC 50.502(c)(2) in the original Construction Permit decision (AQ1201CPT01) and in the discussions regarding the current change in project scope. This additional classification triggers an ambient SO<sub>2</sub> AAAQS demonstration per 18 AAC 50.540(c)(2). The Department didn't notice this missing element of ExxonMobil's application until just before public noticing the preliminary permit decision for Construction Permit AQ1201CPT02. Rather than delaying the project, the Department conducted its own ambient SO<sub>2</sub> analysis and is reporting the results of that analysis in this memorandum.

### **AMBIENT AIR POLLUTANT DATA**

40 CFR 52.21(m)(1) requires PSD applicants to submit ambient air monitoring data describing the air quality in the vicinity of the project, unless the existing concentration or the project impact is less than the significant monitoring concentration (SMC) provided in 40 CFR 52.21(i)(5). The requirement only pertains to the pollutants subject to PSD review. If monitoring is required, the data are to be collected prior to construction. Hence, these data are referred as "pre-construction monitoring" data. Ambient background data may also be needed to supplement the estimated ambient impact from the proposed project. ExxonMobil's approach for meeting the pre-construction data needs is discussed below. ExxonMobil's approach for meeting the background data needs is described in the *Offsite Impact* section of this memorandum.

### **Pre-Construction Monitoring**

Pre-construction monitoring data must be collected at a location and in a manner that is consistent with the U.S. Environmental Protection Agency's (EPA's) *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA-450/4-87-007), which is adopted by reference in 18 AAC 50.035(a)(5). In summary, the data must be collected at the location(s) of existing and proposed maximum impacts, the data must be current, and the data must meet the state and PSD quality assurance requirements in accordance with 18 AAC 50.215(a).

ExxonMobil fulfilled the pre-construction monitoring requirement for all PSD-triggered pollutants, save PM-10, by collecting PSD-quality ambient data at the project site. ExxonMobil collected pre-construction PM-10 data as well, but the data does not meet the PSD quality assurance requirements. ExxonMobil instead demonstrated in their permit application that the PM-10 project impacts are below the SMC, which eliminates the need for PM-10 pre-construction monitoring data. Additional information regarding their PM-10 SMC demonstration is provided later in this discussion.

The Department’s review and approval of ExxonMobil’s monitoring efforts at the project site, first submitted for Construction Permit AQ1201CPT01, are detailed in the 4 June, 2012 modeling memorandum. ExxonMobil did not resubmit the previously provided ambient monitoring data for this permit application. Therefore, the Department is reiterating the maximum monitored concentrations in Table 1. Most of the reported values are in the form of the ambient standard<sup>5</sup>, however, the first-high concentration for CO was conservatively used rather than the second-high value allowed under the standard. The Department is reporting the gaseous pollutants on a mass basis, i.e. micrograms per-cubic meter ( $\mu\text{g}/\text{m}^3$ ), which is the convention used in modeling, rather than on a volumetric basis, i.e. parts per million by volume (ppmv), which is typically used in monitoring report such as ExxonMobil’s. Particulates are only measured and reported on a mass basis and are presented on a mass basis. The ambient standard for each pollutant is provided for reference.

**Table 1. Pre-construction monitoring data collected at Point Thompson**

Air Pollutant	Averaging Period	Monitoring Period	Max. Concentration ( $\mu\text{g}/\text{m}^3$ )	AAQs ( $\mu\text{g}/\text{m}^3$ )	% of AAQs
NO <sub>2</sub>	1-hour	3/2010 – 2/2011	145	188	77%
	Annual		7.5	100	8%
PM-2.5	24-hour	12/2009 – 11/2010	12.7	35	36%
	Annual		2.6	15	17%
O <sub>3</sub>	8-hour	9/2009 – 2/2011 <sup>6</sup>	92	150	63%
CO	1-hour	9/2009 – 8/2010	2,200	40,000	5%
	8-hour		1,300	10,000	13%

All of the monitored concentrations are less than the AAQs. It is likely that some of the concentrations include impacts from the temporary drilling operations that occurred on the pad during the monitoring efforts.

ExxonMobil used computer analysis (modeling) to compare the PM-10 project impacts to the pre-construction SMC threshold for that pollutant. ExxonMobil used the data and methodology discussed in the *Source Impact Analysis* section of this memorandum. The maximum project impacts are shown in Table 2, along with the SMC threshold.

**Table 2. Maximum modeled PM-10 impacts compared to the pre-construction monitoring SMC**

Air Pollutant	Averaging Period	Project Impact ( $\mu\text{g}/\text{m}^3$ )	Monitoring Threshold ( $\mu\text{g}/\text{m}^3$ )
PM-10	24-hour	9.74 <sup>a</sup>	10

Table Notes

<sup>a</sup> 1h concentration

<sup>5</sup> The 1-hour NO<sub>2</sub> and 24-hour PM-2.5 ambient air quality standards are based on three-year data sets. However, the PSD rules only require 4-to-12 months of pre-construction ambient monitoring data. Therefore, the reported values are based on 12-months of data.

<sup>6</sup> ExxonMobil submitted concurrent O<sub>3</sub> data with the NO<sub>2</sub> data. Therefore, they had two reporting periods for O<sub>3</sub>: 1 September, 2009 through 31 August, 2010; and 1 March, 2010 through 28 February, 2011.

ExxonMobil's modeled PM-10 impacts are below the SMC for that pollutant. Therefore, they avoid the need to conduct pre-construction monitoring for PM-10 in accordance with 40 CFR 52.21(i)(5)(i).

## **SOURCE IMPACT ANALYSIS**

ExxonMobil used modeling to predict the ambient NO<sub>2</sub>, CO, PM-10, and PM-2.5 air quality impacts; they used a qualitative approach to address the O<sub>3</sub> impacts. SLR conducted the aforementioned analyses on their behalf. The Department additionally provided their own ambient analysis of SO<sub>2</sub> impacts, as previously discussed in the Project Submittal section of this memorandum. The Department's findings regarding ExxonMobil's modeling analysis, along with a discussion regarding its own SO<sub>2</sub> analysis, are provided below. The Department's findings regarding the qualitative O<sub>3</sub> assessment is provided in the *Ozone Impact* section of this memorandum.

### **Approach**

ExxonMobil's permit application for AQ1201CPT01 described various activities and groupings of EUs that were specifically associated with construction, operations, and drilling activities at the Point Thomson field. Said application compartmentalized these activities and EUs into three distinct scenarios indicative of the multi-year project timeline. ExxonMobil described these three scenarios as:

- Construction and Operations;
- Construction and Drilling; and
- Operations and Drilling.

While the above phases reflect the various stages of the Point Thomson development, ExxonMobil assumed all phases occur simultaneously in their ambient demonstration. ExxonMobil used this same, conservative assumption in their current permit application. However, ExxonMobil did change the several aspects of their ambient demonstration in their application for Construction Permit AQ1201CPT02. In summary, ExxonMobil:

- Revised the EU inventory, stack parameters, and operational assumptions with updated information;
- Decreased the conservative nature of their increment analysis by no longer assuming that all construction activities are increment consuming;
- Added a public access corridor along the southern end of the central pad; and
- Switched their NO<sub>2</sub> modeling algorithm from the Plume Volume Molar Ratio Method (PVMRM) to the Ozone Limiting Method (OLM).

Additional details regarding ExxonMobil's increment modeling approach, including the construction-related EUs excluded from the increment analyses, are discussed below. The details regarding the EU inventory and stack parameters, and their NO<sub>2</sub> modeling assessment, are provided later in this memorandum.

### Increment Analysis

Point Thomson is located within a Class II area of the Northern Alaska Intrastate Air Quality Control Region. The major source baseline date for annual NO<sub>2</sub> is 8 February, 1988. The major source baseline date for annual and 24-hour PM-10 is 13 November, 1978. The major source baseline date for PM-2.5 is 20 October, 2010. Therefore, all permanent EUs are increment consuming since they will be installed after these dates. There are no Class II increments for the other PSD-triggered pollutants and averaging periods, i.e. CO<sub>2e</sub>, 1-hour NO<sub>2</sub>, 1-hour CO, and 8-hour CO.

ExxonMobil included all of their permanent EUs in their increment analyses except for those listed in the Excluded Permanent Units section of this memorandum. Their approach for handling temporary EUs is discussed in the Temporary Construction Activities and Intermittent Well Servicing Equipment sections of this memorandum.

### Temporary Construction Activities

18 AAC 50.215(b)(2)(A) allows temporary construction activities to be excluded from an increment analysis. A temporary construction activity is defined in 18 AAC 50.990(107) as “...construction that is completed in 24 months or less from the date construction begins...[and] includes any period of inactivity during that 24-month period”. The term *begin actual construction* is defined in 40 CFR 52.21(b)(11) as the “...initiation of physical on-site construction activities on an emissions unit which are of a permanent nature”. The types of activities that indicate construction has begun include, but are not limited to, the installation of building supports and foundations, laying underground pipe-work, and the construction of permanent storage structures.

ExxonMobil excluded EUs 201, 202, 242, 243, 244, 245, and 247 from their increment analysis under the assertion that these units will not operate past the first 24-months of construction and are therefore considered temporary construction activities. The Department is therefore requiring ExxonMobil to report when construction begins and to remove the aforementioned EUs within 24-months after beginning actual construction.

### Intermittent Well Servicing Equipment

The Department offers guidance<sup>7</sup> for North Slope applicants regarding the ambient assessment of intermittent well servicing equipment. In this guidance, the Department notes that intermittently used oilfield support equipment are not subject to an increment analysis due to “...their portable nature, their infrequent intermittent use at any given location, and how EPA and other states manage such emission units”. ExxonMobil therefore did not include intermittent well servicing equipment (EUs 36 – 46) in their increment analyses.

The Department also allows North Slope applicants to exclude intermittent oil field support equipment rated at less than 400 brake-horsepower (bhp), or with an equivalent heat-input rating of 2.8 million British thermal units per hour (MMbtu/hr), from the AAAQS analysis *if* they agree to use fuel with a maximum sulfur content of 15 parts per million by weight (ppmw) in their diesel-fired intermittent well servicing equipment. Ultra Low Sulfur Diesel (ULSD) fuel meets this criterion.

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<sup>7</sup> *Intermittently Used Oilfield Support Equipment Policy and Procedure* no. 04.02.105 dated 20 November, 2006

ExxonMobil plans to use ULSD when operating their diesel-fired EUs. They therefore could have excluded the smaller intermittent well servicing EUs from their AAAQS analyses. However, they instead took the conservative approach of including all intermittently operated oilfield support equipment (EU 36 – 46) in their AAAQS analyses.

#### Excluded Permanent Units

ExxonMobil previously excluded several relatively small and distant EUs from their AAAQS and increment modeling analyses conducted in support of Construction Permit AQ1201CPT01. They carried the exclusion of these EUs forward for the current ambient analysis. The excluded units are as follow:

- EUs 209 and 210 (90 bhp raw water skid generators); and
- EUs 114 and 223 (490 bhp standby airstrip generators).

EUs 209 and 210 are located on the water access pad approximately 3.2 km from the central pad; EUs 114 and 223 are located at the airstrip approximately 3.2 km from the central pad. ExxonMobil's exclusion of these EUs continues to be reasonable. These units are relatively small and are located well beyond the areas of maximum impact. Therefore, they would have little, if any, influence on the modeled results.

ExxonMobil noted in their 1 April, 2013 supplement that they are no longer planning to install EUs 219 and 220 (the two "32 Man Camp Generator Engines"). They therefore removed these units from their modeling analysis. The Department has likewise removed these units from the EU inventory in Construction Permit AQ1201CPT02.

#### **Model Selection**

There are a number of air dispersion models available to applicants and regulators. The EPA lists these models in their *Guideline on Air Quality Models* (Guideline), which the Department has adopted by reference in 18 AAC 50.040(f). ExxonMobil used EPA's AERMOD Modeling System (AERMOD) for their ambient analysis, which is an appropriate modeling system for this application.

The AERMOD Modeling System consists of three major components: AERMAP, used to process terrain data and develop elevations for the receptor grid and EUs; AERMET, used to process the meteorological data; and the AERMOD dispersion model, used to estimate the ambient pollutant concentrations.

ExxonMobil used meteorological data processed with AERMET version 11059, the most current version at the time of their application, but did not use the AERMAP component since there are no significant terrain features within their modeling domain. They used AERMOD version 12060 for their initial ambient analysis. EPA has subsequently released AERMET and AERMOD versions 12345. ExxonMobil continued to use AERMOD version 12060 and the meteorological data as processed by AERMET version 11059 in their supplemental analyses, presumably to maintain consistency throughout their application. The Department generally does not make applicants update their permit applications if there is a model change subsequent to

their submittal. ExxonMobil's use of these versions is therefore acceptable, but they should use the current version in future submittals. The Department used AERMOD version 12345 in its analysis of the SO<sub>2</sub> impacts.

### **Meteorological Data**

AERMOD requires hourly meteorological data to estimate plume dispersion. According to the Guideline, a *minimum* of one-year of site-specific data, or five years of representative National Weather Service (NWS) data should be used. When modeling with site-specific data, the Guideline states that up to five years should be used when available to account for year-to-year variation in meteorological conditions.

ExxonMobil used the same processed meteorological data set for this analysis as used in support of Construction Permit AQ1201CPT01. Specifically, they collected surface meteorological data during their pre-construction monitoring effort in order to use site-specific data in their modeling analysis. Site-specific meteorological data must meet the PSD quality assurance requirements outlined in EPA's *Meteorological Monitoring Guidance for Regulatory Modeling Applications* in accordance with 18 AAC 50.215(a)(3). MACTEC Engineering and Consulting, Inc. (MACTEC), on behalf of the Department, reviewed the data under these requirements and recommended that the Department consider the data as PSD-quality in their 18 May, 2011 findings report. The Department accepted MACTEC's recommendation on 19 May, 2011.

ExxonMobil used one year of site-specific surface data, with concurrent NWS upper air data from Barrow, Alaska to conduct their modeling analysis. They substituted missing surface data with coincident Automated Surface Observation System (ASOS) NWS data from Deadhorse, Alaska, which is located approximately 90 km west of Point Thomson.

The Department does not generally allow applicants to use surrogate wind data from distant locations. However, the Department allowed it in this particular case because the site-specific data was nearly complete, i.e., it had minimal hours of missing data, and a sensitivity analysis the Department conducted in support of Construction Permit AQ1201CPT01 demonstrated that the substitution has an inconsequential affect on the analysis.

AERMET requires the area surrounding the meteorological tower to be characterized with regard to the following three surface characteristics: noon-time albedo, Bowen ratio, and surface roughness length. EPA has provided additional guidance regarding the selection and processing of these values in their *AERMOD Implementation Guide*.

ExxonMobil derived their domain specific surface parameters using the tundra and Arctic Ocean values previously approved by the Department for North Slope sources. Individual parameter values are assigned by month in order to adjust the surface characteristics according to each season. The Department notes that this approach is carried forward from Construction Permit AQ1201CPT01 and agrees with ExxonMobil's methodologies, which observe guidance provided by both EPA and Department in calculating surface parameters. The accepted values are illustrated in Table 3.

The Department noted, in their 4 June, 2012 modeling memorandum, that ExxonMobil used an incorrect anemometer height in their Stage 1 AERMET run. Specifically, ExxonMobil used a height of 12.5 meters (m) instead of the actual 16.8 m. The Department then determined that this error was not substantive, based on a sensitivity check, but recommended ExxonMobil use the correct anemometer height in future submittals. Since ExxonMobil did not re-process the meteorological parameters for this ambient assessment, the incorrect anemometer height has been carried forward. The Department will not require ExxonMobil to re-process the meteorological parameters for this submission noting a similar likelihood for non-substantive impacts on the resultant analysis, but will likely require ExxonMobil to re-process the data with the correct anemometer height in future submittals. Reprocessing the meteorological data would be especially warranted since EPA has released a newer version of AERMET.

**Table 3. Approved AERMET surface parameters for Point Thompson**

Surface Parameter		Winter Value	Summer Value
Albedo		0.139	0.800
Bowen Ratio		0.277	1.737
Surface Roughness Length (m)			
Sector	Range		
1	0° - 120 °	0.001	0.001
2	120 ° - 150 °	0.003	0.002
3	150 ° - 270 °	0.020	0.004
4	270 ° - 360 °	0.002	0.002

*Table Notes: For the purposes of the Point Thomson AERMET surface parameters, summer is defined as June through September, and winter is defined as October through May.*

### Design Concentrations

EPA generally allows applicants to use modeled concentrations that are consistent with the form of the standard, or increment, if at least one year of representative site-specific, or five years of representative NWS data are used. Applicants must also use the first highest 24-hour average PM-2.5 concentration, or the multi-year average of the first highest 24-hour concentrations, when using a background value that is consistent with the form of the standard. In all cases, applicants must compare the highest modeled concentration to the deterministic annual average standards or increments, SILs, and all pre-construction monitoring thresholds.

ExxonMobil performed increment analyses using design concentrations based on the highest modeled concentration for each pollutant with an annual averaging time; they used a design concentration based on the highest second-high concentration for those pollutants with short-term averaging times. Their AAAQS analyses generally used design concentrations that are consistent with the form of each pollutant and averaging time. However, they used the first highest 24-hour PM-2.5 concentration, for the reason described above. For the SO<sub>2</sub> analysis, the Department compared the maximum modeled concentrations to the SILs and the modeled concentrations in the form of the standard for the SO<sub>2</sub> AAAQS analysis. The approach used for each AAAQS design concentration is summarized in Table 4. The ranking of the background concentrations are also provided.

**Table 4. Modeled design concentrations in the Point Thomson AAAQS analyses**

Air Pollutant	Averaging Period	Modeled Concentration	Background Concentration	Consistent with Form of Standard
NO <sub>2</sub>	1-hour	h8h	2010-2011 average of the 98 <sup>th</sup> percentile at Point Thomson	Yes
	Annual	Maximum	Annual average at Point Thomson 2010-2011	Yes
PM-2.5	24-hour	h1h	2009-2010 average of the 98 <sup>th</sup> percentile at Point Thomson	Yes
	Annual	Maximum	Annual average at Point Thomson 2009-2010	Yes
SO <sub>2</sub>	24-hour	h2h	Highest monitored at Point Thomson 2009-2010	
	1-hour	h4h	Highest monitored at Point Thomson 2009-2010	
PM-10	24-hour	h2h	Highest monitored at CCP since 2008	Yes
CO	1-hour	h2h	First-highest 1-hour average during 2009-2010 at Point Thomson	Yes
	8-hour	h2h	First-highest 8-hour average during 2009-2010 at Point Thomson	Yes

*Table Notes: The annual and 3-hour SO<sub>2</sub> approach are not reported since a cumulative analysis was not needed. See the Results section of this memorandum for additional information.*

### Emissions Unit Inventory

ExxonMobil included the complete EU inventory at Point Thomson in their modeling analysis, except as previously noted in the *Temporary Construction Activities* and *Intermittent Well Servicing Equipment* sub-sections and as noted in this section. ExxonMobil assumed the non-concurrent operation of several EUs, which is summarily discussed. All EUs were characterized as point sources.

### Non-Concurrent Operations

ExxonMobil requests that the Department revise the non-concurrent operational limits from those authorized in AQ1201CPT01. The revised inventory of EUs that may not operate concurrently is as follows:

- 105 and 106;
- 201 and 202;
- 213 and 214;
- 215 and 216;
- 217 and 218;
- 240 and 241;
- 242 and 243;
- 244 and 245;
- EUs 203, 203A, 204, 204A, and 205: no more than four-of-five units;
- EUs 206, 206A, 207, 207A, and 208: no more than four-of-five units; and
- Do not operate EUs 105 and 106 in concurrence with EUs 246 and 247.

This revision omits several unit-pairings that have been removed, or are otherwise excluded from ExxonMobil's analysis for reasons previously discussed. The Department evaluated ExxonMobil's updated analyses and determined them to reflect the above pairings as modeled. Therefore, the amended conditions will be carried forward.

In their 1 April, 2013 application supplement, ExxonMobil provided a revised and combined modeling run for both annual and 1-hour NO<sub>2</sub>. In this revised modeling run, ExxonMobil used an option to allocate discrete hour-of-day operation to select units. Specifically, EUs 107 through 109 were modeled using staggered four-hour operational blocks throughout the daytime; EUs 110 and 111 were modeled using a concurrent 12-hour block in the middle of the daytime. AERMOD calculates a daily high one-hour NO<sub>2</sub> concentration at each receptor based on 24 hourly values. ExxonMobil's daily high only reflects the non-concurrent and part-time operation of these units; it does not reflect the greater impact that would likely occur from concurrent operation. Therefore, the Department will impose additional non-concurrent operational limits for EUs 107 through 111 to protect the 1-hour NO<sub>2</sub> standard. The Department also notes that only two-of-three units among EUs 237 through 239 will be authorized to operate to protect the 1-hour NO<sub>2</sub> standard.

### **Emission Rates**

The assumed emission rates have significant roles in an ambient demonstration. Therefore, the Department checks these parameters very carefully. The Department observed emission rates for multiple units that did not match what it had calculated for all pollutants and averaging times; these rates remained inconsistent across multiple supplemental submissions. Both the Department and ExxonMobil engaged in an iterative process of revised assumptions, corrected emission factors, and updated operational limits to remedy the inconsistencies. Exceptions, or items that otherwise warrant additional discussion, are discussed below.

### Solar Turbines

Turbine emissions tend to vary greatly by fuel type, operational load, and inlet air temperature. Applicants typically select the worst-case emission rate for their modeling analysis, unless they have demonstrated through a sensitivity analysis that the worst-case impacts occur under other conditions due to less buoyant plume characteristics.

ExxonMobil will operate four 7,520 kilowatt (kW) Solar 70 Taurus turbines as EUs 101 through 104; the latter two units have dual fuel capability and may each fire ULSD for up to 2,000 hours-per-year. All units are equipped with SoLoNO<sub>x</sub> controls and may operate outside of this control regime no more than 500 hours-per-year between all. ExxonMobil correctly assumed the short-term emission rates for these units in modeling the short-term deterministic standards and increments for each applicable pollutant. However, for EUs 101 and 102 they assumed a modeled emission rate for the 1-hour NO<sub>2</sub> standard that exclusively represents the SoLoNO<sub>x</sub> regime, a rate that is roughly half of the non-SoLoNO<sub>x</sub> rate. The Department notes that since this standard is probabilistic, and that the maximum potential operation out of this regime for any one turbine is 500 hours-per-year, the approach is representative of typical operation for these two turbines. ExxonMobil used the annual ULSD restriction in their annual NO<sub>2</sub> increment analysis. The Department is therefore incorporating this assumption as an ambient air condition.

### Well Test Equipment

ExxonMobil excluded EUs 36 through 46 from their increment analyses as previously described in the *Approach* section. However, they included these units in their AAAQS analyses even though they could have excluded the smaller units per the Department's Intermittently Used

Oilfield Support Equipment policy. The Department also notes that ExxonMobil assumed an annualized modeled emission rate for these units, rather than the short-term rate, for assessing compliance with the 1-hour NO<sub>2</sub> standard.<sup>8</sup> ExxonMobil previously stated, as cited in the Department's 4 June, 2012 modeling memorandum, that the approach is "*...in accordance with EPA guidance regarding intermittently used equipment*".

The Department previously assumed that ExxonMobil was citing EPA's 1 March, 2011 guidance regarding the modeling of 1-hour NO<sub>2</sub>. While EPA did not specifically address periodically operated EUs, such as well testing equipment, in this guidance, the general discussion is still helpful. EPA suggested that an emergency generator with an operational limit of 500 hours-per-year could be modeled in a 1-hour NO<sub>2</sub> demonstration using an annualized emission rate. The Department continues to accept ExxonMobil's modeled approach since these EUs will have enforceable limits on par with EPA's example, i.e., each unit will have a limit of 1,080 hours-per-year, save EU 37 at 500 hours-per-year. The Department will, however, continue to impose these operational restrictions as ambient air conditions to protect the 1-hour and annual NO<sub>2</sub> standards noting the same modeling approach as previously assessed.

#### Standby Camp Generators and Fine Water Pump Generators

For their short-term analyses, ExxonMobil modeled select EUs using less-than full-time short-term operational emission rates. This issue was detailed at length in the Department's 4 June, 2012 modeling memorandum. Therefore, the Department will impose short-term operational limits on the following EUs to protect the short-term standards and increments:

- EUs 107 through 109, no more than 4 hours-per-day per unit; and
- EUs 110 and 111, no more than 12 hours-per-day per unit.

#### EUs with Annual Emission Rate Assumptions

ExxonMobil modeled select EU-groupings with intent to represent a shared annual operational limit between those EUs modeled. Therefore, the Department will impose shared operational limits on the following EUs to protect all the annual standards and increments:

- EUs 105 and 106, no more than 8,760 hours-per-year combined;
- EUs 213 and 214, no more than 8,760 hours-per-year combined;
- EUs 215 and 216, no more than 8,760 hours-per-year combined;
- EUs 217 and 218, no more than 8,760 hours-per-year combined;
- EUs 224 through 227, no more than 23,370 hours-per-year combined;
- EUs 237 through 239, no more than 11,690 hours-per-year combined;
- EUs 240 and 241, no more than 8,760 hours-per-year combined;
- EUs 242 and 243, no more than 8,760 hours-per-year combined; and
- EUs 244 and 245, no more than 8,760 hours-per-year combined.

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<sup>8</sup> ExxonMobil assumed the maximum short-term emission rates for these EUs in assessing compliance with the short-term PM-10, PM-2.5, and CO AAAQS impacts.

### Stack Parameters

The assumed stack parameters, such as height, diameter, exit velocity, and exhaust temperature, have significant roles in an ambient demonstration. Therefore, the Department checks these parameters very carefully.

The Department generally found the modeled stack parameters to be consistent with the vendor information or expectations for similarly sized units. The exceptions, or items that otherwise warrant additional discussion, are discussed as follows.

### Stack Heights

ExxonMobil modified the stack heights as modeled for Construction Permit AQ1201CPT01. In the current analysis, some of the stack heights are within ranges expected for this type of facility. However, the stacks for the solar turbines and the rig engine stacks are notably taller than the associated structures. The stacks for the permanent camp generators are also taller than what would be expected for construction equipment, and the stacks for the permanent waste incinerators are likewise relatively tall. The Department notes that ExxonMobil changed the modeled stack heights among its EU inventory across its multiple supplemental modeling submissions. Therefore, the Department is imposing the minimum stack height requirements, listed in Table 5, as ambient air conditions based on their most recent supplemental modeling submission.

**Table 5. Minimum stack height requirements**

EU	Model ID	Description	Minimum Stack Height (m)
9	akcgen1	Camp Generators	7.6
10	ackgen2		
37	wellflar	Well-Testing Flare	22.9
47	rigeng1	Drill Rig Generator Engines	13.5
48	rigeng2		
49	rigeng3		
50	rigeng4		
58	rigeng5	Drill Rig Support Generators	
59	rigeng6		
60	rigeng7		
61	rigeng8		
101	solar701	Solar Turbines	27.4
102	solar702		
103	solar703		
104	solar704		
105	wastein1	Waste Incinerators	14.3
106	wastein2		
112	hpflare	HP Flare	36.6
113	lpflare	LP Flare	
206	G_PERMC1	Permanent Camp Generators	12.2
207	G_PERMC2		
208	G_PERMC3		
206A	G_PERMC4		
207A	G_PERMC5		

### Horizontal and Capped Stacks

The presence of non-vertical stacks, or stacks with rain caps, requires special handling in an AERMOD analysis. The proper approach for characterizing horizontal and capped stacks is described in EPA's, *AERMOD Implementation Guide*. For horizontal and capped stacks subject to building downwash, the user should input the actual stack diameter and exit temperature, but set the exit velocity to a nominally low value, e.g. 0.001 meters-per-second. If the horizontal or capped stack is *not* subject to downwash, then a nominally low exit velocity should be used along with an artificially large diameter such that the actual exhaust flow rate is maintained. Minor adjustments to the stack height may also be warranted.

EPA has developed a non-default option in AERMOD that will revise the stack characteristics as warranted for stacks that are identified as capped or horizontal. EPA Region 10 granted the Department permission to use this option in general in October 2007<sup>9</sup>. ExxonMobil's modeling analyses characterize the following EUs as if they had horizontal or capped stacks using this non-default option:

- EUs 105 and 106, Permanent Waste Incinerators;
- EUs 107 through 109, Standby Camp Generators;
- EUs 7 and 8, Drill Rig Support Shop Heaters;
- EUs 14 and 15, Warehouse Heaters;
- EUs 16 and 17, Bulk Tank Storage Area Boilers; and
- EUs 237 through 239, Start-up Generators.

ExxonMobil used the option within AERMOD for revising the stack characteristics, as warranted, for simulating the impact from these EUs. Because the modeled impacts from horizontal and capped stacks are typically greater than the impacts from stacks with vertical, uncapped discharges, the Department is including permit conditions that require vertical, uncapped stacks, except for the EUs listed above.

### **Ambient PM-2.5 Modeling**

PM-2.5 is either directly emitted from a source, as primary emissions, or formed through chemical reactions in the atmosphere, as secondary formation. AERMOD is an acceptable model for performing near-field analysis of the primary emissions, but EPA has not developed a near-field model that includes the necessary chemistry algorithms for estimating secondary impacts.

To address this lack of a comprehensive, near-field modeling tool for secondary impacts, EPA issued modeling guidance to provide recommended approaches for demonstrating compliance with the PM-2.5 ambient air quality standard.<sup>10</sup> This guidance provides that much of the secondary formation from background sources should be adequately accounted for, in most cases, through the use of representative ambient monitoring data. EPA further asserts that the peak primary impacts and the peak secondary impacts from the source "*...are not likely to be well-correlated in space or time*", i.e., they will likely occur in substantively different locations and at different times. This is because secondary PM-2.5 formation is a complex photochemical

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<sup>9</sup> E-mail from Herman Wong (EPA R10) to Alan Schuler (Department); *RE: Capped/Horizontal Stack Issue* dated 2 October, 2007.

<sup>10</sup> EPA Memorandum: *Modeling Procedures for Demonstrating Compliance with PM<sub>2.5</sub> NAAQS*; 23 March, 2010.

reaction that requires a mix of precursor pollutants in sufficient quantities for significant formation to occur. As such, it is unlikely that there is sufficient time for the secondary reaction to substantively occur within the immediate near-field.

ExxonMobil's used site-specific background data that complies with EPA's recommendation; see the *Off-site Impacts* section of this memorandum for additional detail. They also evaluated the primary PM-2.5 impacts in their ambient demonstration. Since the near-field formation of secondary particulates from the Point Thompson EUs would likely be immaterial, and since they provided site-specific background data in comport with EPA's recommendation, the Department accepts ExxonMobil's overall analysis as suitable for assessing the secondary PM-2.5 impacts.

### **Ambient NO<sub>2</sub> Modeling**

The modeling of ambient NO<sub>2</sub> concentrations can sometimes be refined through the use of ambient air data or assumptions. Section 5.2.4 of the Guideline describes several approaches that may be considered in modeling annual average NO<sub>2</sub> impacts. These approaches are also generally applicable in modeling 1-hour NO<sub>2</sub> impacts.

ExxonMobil used the Ozone Limiting Method (OLM)<sup>11</sup> to refine the estimated ambient NO<sub>2</sub> concentrations. The use of OLM is appropriate, but warrants discussion.

### EPA and Department Approval

OLM is a non-Guideline method when used to evaluate the 1-hour NO<sub>2</sub> impacts and therefore, requires EPA and Department approval in accordance with 18 AAC 50.215(c)(2). EPA Region 10 (R10) granted ExxonMobil permission to use OLM for the Point Thomson project on 7 January, 2013.<sup>12</sup> The Air Permits Program Manager gave his approval on 14 January, 2013.<sup>13</sup>

### Public Comment

The use of a non-Guideline model is subject to public comment. Therefore, the Department is seeking public comment regarding the use of OLM in the public notice for the preliminary permit decision.

### In-stack NO<sub>2</sub>-to-NO<sub>x</sub> Ratio

The oxides of nitrogen (NO<sub>x</sub>) emissions created during combustion is partly nitric oxide (NO) and partly NO<sub>2</sub>. After the combustion gas exits the stack, additional NO<sub>2</sub> is created as the exhaust mixes with atmospheric ozone.

The assumed NO<sub>2</sub>-to-NO<sub>x</sub> in-stack ratio is a variable that must be defined for each EU that generates NO<sub>x</sub> emissions. While the OLM algorithm can be non-linear in relation to the in-stack ratio, the use of larger than expected values can lead to overly conservative results, while the use of smaller than expected values can lead to understated NO<sub>2</sub> impacts. As such, unit-specific data should be used when available, such as vendor or source test data from a representative EU.

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<sup>11</sup> ExxonMobil used the Plume Volume Molar Ratio Method (PVMRM) in Construction Permit AQ1201CPT01.

<sup>12</sup> E-mail from Herman Wong (EPA R10) to James Renovatio (Department); *RE: OLM Request - ExxonMobil Point Thompson minor permit*; 7 January, 2013.

<sup>13</sup> The Commissioner delegated his authority regarding the use of non-guideline models to the Air Permits Program Manager on 3 June, 2008.

When source-specific data is not available, a 0.50 in-stack ratio may be used without justification for purposes of modeling the 1-hour NO<sub>2</sub> impact. According to EPA's March 2011 NO<sub>2</sub> modeling guidance, this value represents "*a reasonable upper bound based on the available in-stack data*". Alternative values may also be used if there is adequate justification as to why the given value is reasonable. EPA has not provided a similar "default" ratio for the purposes of modeling annual average NO<sub>2</sub> impacts.

For their ambient demonstrations involving the NO<sub>2</sub> standards and increment, ExxonMobil used a 0.10 ratio for all of their EUs save the four turbines; the latter EUs are assigned an in-stack ratio of 0.3. The Department previously addressed this issue at length in their 4 June, 2012 modeling memorandum. While ExxonMobil's approach suitable for this application, the Department notes that the aforementioned discussion of the issue provides a factual basis for requiring applicants to justify the use of ratios below those recommended by EPA guidance.

#### Ozone Data

OLM requires ambient ozone data in order to determine how much of the NO is converted to NO<sub>2</sub>. ExxonMobil used site-specific ozone data measured during their September 2009 through August 2010 pre-construction monitoring efforts. This is the same monitoring period as that used for the meteorological data. The data suggests that ozone-scavenging occurred during the monitoring period. However, for Construction Permit AQ1201CPT01, ExxonMobil adequately demonstrated that these events do not substantively affect their overall analysis. Therefore, the continued use of site-specific data is appropriate.

#### **SO<sub>2</sub> Emissions**

SO<sub>2</sub> emissions are directly related to the sulfur content of a particular fuel fired by an EU. The sulfur content of liquid fuel is found in the form of elemental sulfur, while the sulfur content of fuel gas is found in the form of hydrogen sulfide (H<sub>2</sub>S). ExxonMobil's Point Thompson EUs consist of both liquid- and fuel gas-fired equipment and were modeled by the Department using the maximum short-term emission rate. Based on ExxonMobil's application, the Department modeled their liquid-fired EUs assuming the use of ultra-low sulfur diesel (ULSD) with a sulfur content of 0.0015 weight percent (wt%). Also based on ExxonMobil's application, the Department modeled their fuel gas-fired EUs assuming the use of fuel gas with a maximum H<sub>2</sub>S content of 125 parts per million by volume (ppmv); the low-pressure flare, EU 113, and all flare pilot and purge regimes were modeled assuming a maximum H<sub>2</sub>S content of 300 ppmv. Therefore, the Department is including the following assumptions as enforceable limits to protect the 1-hour, 3-hour, 24-hour, and annual SO<sub>2</sub> AAAQS:

- ULSD or 0.0015 wt% fuel sulfur for all EUs firing liquid fuels;
- 300 ppmv for the LP flare EU 113 and all flare pilot and purge regimes;
- 125 ppmv for all other EUs firing fuel gas (excluding the pilot and purge of the HP flare EU 112).

#### **Ambient Air Boundary**

For purposes of air quality modeling, *ambient air* means outside air to which the public has access. Ambient air typically excludes that portion of the atmosphere within a stationary source's boundary. ExxonMobil continued to use the pad edge as the ambient air boundary, which is an

appropriate boundary for North Slope sources. However, they are now required to provide a public trail across the southern edge of the central pad. ExxonMobil security personnel will manage access along the trail and ensure the public does not wander into the restricted areas using the procedures described in ExxonMobil's February 2013 public access control plan.<sup>14</sup> The Department is requiring compliance with the public access control plan as an ambient air condition.

### **Worker Housing**

ExxonMobil will need to house their workers on site due to the project's remote location. Worker housing areas must be treated as ambient air, except under the conditions described in the Department's *Ambient Air Quality Issues at Worker Housing* policy (Policy and Procedure No. 04.02.108 – October 8, 2004). The conditions are:

- 1) the worker housing area is located within a secure or remote site;
- 2) the worker housing area is for official business/worker use only; and
- 3) the operator has a written policy stating that the on-site workers are on 24-hour call.

When these conditions are not met, the general area surrounding the worker housing must be included in the ambient analysis using a receptor grid density that is commensurate with the approach used to determine the receptor grid density at locations beyond the source's ambient air boundary. Receptors are not specifically placed at windows and building air intakes though, since EPA does not consider the air at open windows and air intakes as ambient.<sup>15</sup>

ExxonMobil previously demonstrated that their worker housing area is not ambient air. Their basis for excluding the working housing area from ambient air remains valid. The location is remote and will be used for business purposes only, i.e. family visitors will not be permitted, which meets the first and second conditions of the Department's worker housing policy. ExxonMobil also has a written policy that all personnel are on 24-hour call while on-site, which meets the third condition.<sup>16</sup>

### **Receptor Grid**

ExxonMobil used the following grid density:

- 20-m resolution along the pad edge;
- 25-m resolution from the pad edge to 200 m outward;
- 50-m resolution from 200 m to 500 m outward;
- 100-m resolution from 500 m to 1.5 km outward; and
- 250-m resolution from 1.5 km to 5 km outward.

ExxonMobil additionally placed receptors along the public access trail that crosses the southern edge of the pad. The Department finds ExxonMobil's receptor grid has sufficient resolution and coverage to determine the maximum impacts.

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<sup>14</sup> ExxonMobil submitted their Public Access Control Plan on 15 March 2013.

<sup>15</sup> Letter from John Seitz (Director, EPA OAQPS) to Daniel Gutman; 13 April, 1992.

<sup>16</sup> Al Trbovich (SLR) e-mailed the worker housing policy to the Department's Pat Dunn on 3 February, 2012.

### **Downwash**

Downwash refers to conditions where nearby structures influence plume dispersion. Downwash can occur when a stack height is less than a height derived by a procedure called *Good Engineering Practice* as defined in 18 AAC 50.990(42). The modeling of downwash-related impacts requires the inclusion of dimensions from nearby buildings.

EPA has established specific algorithms for determining which buildings must be included in the analysis and for determining the profile dimensions that would influence the plume from a given stack. EPA has incorporated these algorithms into the Building Profile Input Program (BPIP) computer program. ExxonMobil used EPA's PRIME version of BPIP (BPIP-PRM, version 04274) to determine the building profiles needed by AERMOD. This is an appropriate version of BPIP.

### **Off-Site Impacts**

The impact from neighboring off-site sources must be accounted for in a cumulative impact assessment. In accordance with Section 8.2.3 of the Guideline, "*all sources expected to cause a significant concentration gradient in the vicinity of the [applicant's source] should be explicitly modeled*". The impact from other sources can be accounted for through ambient monitoring (background) data.

The off-site inventory and background concentration must be evaluated on a case-by-case basis for each of the modeled pollutants. Once the background concentration is determined, it is added to the modeled concentration to estimate the total ambient concentration. Hence, background concentrations are typically needed for all air pollutants included in an AAAQS compliance demonstration, regardless of whether or not PSD pre-construction monitoring was required. The data used to represent the background concentration may come from the pre-construction monitoring effort or from some other ambient monitoring effort that represents the non-modeled sources, such as natural, area and long-range transport.

There are no existing stationary sources located near the Point Thomson field, or sources that would otherwise cause a significant concentration gradient. The Department notes that the nearest potential source, the Shell Oil Company's Discoverer drillship, has access to a lease-block that is approximately 15 km<sup>17</sup> away, a distance that is too far to have a significant concentration gradient in the vicinity of Point Thomson. Therefore, ExxonMobil did not include off-site sources in their modeling analysis. They instead relied on their site-specific background data to represent the long-range impacts from off-site sources, as allowed under Section 8.2.2.b of the Guideline.

ExxonMobil used their pre-construction monitoring data, presented in Table 1, as the CO, PM-2.5, and *annual average* NO<sub>2</sub> background concentrations. The Department likewise used ExxonMobil's SO<sub>2</sub> preconstruction data as the background concentrations in its SO<sub>2</sub> AAAQS analysis. The site-specific data used represent very conservative values since they likely include impacts from the drilling operation that occurred during the monitoring effort. The 24-hr PM-2.5 value is consistent with the form of the standard. Therefore, ExxonMobil was required to add the

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<sup>17</sup> ExxonMobil's 20 March, 2012 submittal stated the nearest Shell lease block is 15 *miles* from Point Thomson. The correct unit for this value (15) is "kilometers."

high first-high modeled 24-hour PM-2.5 concentration to this value, as discussed in the Meteorological section of this memorandum.

ExxonMobil was unable to use their PM-10 preconstruction data to represent the background concentration since the data do not meet the PSD quality assurance requirements. They instead presented a value of  $20 \mu\text{g}/\text{m}^3$ . ExxonMobil did not state where the value came from or why it represents the expected background concentration. The Department recognizes it though as the same 24-hour PM-10 background concentration approved by the Department for a BPXA modeling analysis of the Northstar offshore production facility. However, the Department noted in its September 29, 1998 approval of this value for Northstar that “the  $20 \mu\text{g}/\text{m}^3$  concentration may not be used to represent other projects or on-shore background levels without an approved assessment demonstrating the value is representative of the background concentration in the requested area.” The Department finds no basis as to why this value would represent the onshore background concentration at Point Thomson. The Department is therefore using the maximum 24-hour PM-10 concentration measured during the past few years at BPXA’s Central Compressor Plant (CCP) monitoring station. This is an onshore data set from a major North Slope industrial area, which likely provides an upper-end value of the expected background concentration (i.e., the non-modeled impacts) at Point Thomson. The maximum (first high) concentration is  $49 \mu\text{g}/\text{m}^3$ , which occurred during the 2010 monitoring period. The first high concentrations measured in 2009 and 2011 were  $25.2 \mu\text{g}/\text{m}^3$  and  $30 \mu\text{g}/\text{m}^3$ , respectively.

ExxonMobil also used their on-site  $\text{NO}_2$  data for the 1-hour  $\text{NO}_2$  analysis, but in a more selective approach. ExxonMobil did not use the maximum measured 1-hour  $\text{NO}_2$  concentration since it likely includes impacts from the types of EUs that were including in the modeling analysis. In the analysis conducted in support of Construction Permit AQ1201CPT01, ExxonMobil instead used the applicable monthly average concentration.<sup>18</sup> The Department considered this to be a reasonable approach for an isolated source in a remote location, i.e. an area with minimal anthropogenic impacts. ExxonMobil did not vary the 1-hour  $\text{NO}_2$  background concentration in the current analysis, but instead just used the month with the second-highest background concentration ( $34.5 \mu\text{g}/\text{m}^3$ ). ExxonMobil provided no justification for selecting this month and the Department did not take the time to determine whether the second-highest value is justified. The Department is instead using the highest monthly average concentration ( $36.9 \mu\text{g}/\text{m}^3$ ) since that provides the upper-end value, and still demonstrates compliance with the 1-hour  $\text{NO}_2$  AAAQS.

## Results and Discussion

The maximum project-related  $\text{NO}_2$ , CO, PM-10, PM-2.5, and  $\text{SO}_2$  impacts modeled in ExxonMobil’s ambient demonstration, and by the Department in the case of  $\text{SO}_2$ , are shown in Table 6. The SIL for each pollutant and averaging time are also presented for comparison. All impacts, excluding annual and 3-hour  $\text{SO}_2$ , are greater than the corresponding SIL for each pollutant and averaging time modeled. Therefore, ExxonMobil must provide a cumulative impact assessment for those pollutants. In regards to the annual and 3-hour  $\text{SO}_2$  assessment, ExxonMobil has adequately demonstrated that the Point Thomson stationary source will not cause or contribute to a violation of the annual or 3-hour  $\text{SO}_2$  AAAQS.

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<sup>18</sup> ExxonMobil summarized the monthly average  $\text{NO}_2$  concentrations measured at Point Thomson in Table 1 of their 1 November, 2011 submittal.

**Table 6. Maximum project impacts compared to the SIL**

Pollutant	Averaging Period	Modeled Concentration <sup>a</sup> (µg/m <sup>3</sup> )	SIL (µg/m <sup>3</sup> )
NO <sub>2</sub>	Annual	28.1	1.0
	1-hour	212.7	8
CO	8-hour	2,021.6	500
	1-hour	4,234.2	2,000
PM-10	Annual <sup>b</sup>	3.00	1.0
	24-hr	17.2	5.0
PM-2.5	Annual	2.6	0.3
	24-hr	17.2	1.2
SO <sub>2</sub>	Annual	0.8	1.0
	24-hour	7.2	5.0
	3-hour	11.4	25.0
	1-hour	11.7	8

Table Notes

<sup>a</sup> Annual or h1h concentrations, as applicable

<sup>b</sup> There is no annual PM-10 standard, but there is an annual Class II PM-10 increment

The maximum cumulative NO<sub>2</sub>, CO, PM-10, PM-2.5, and 24-hour and 1-hour SO<sub>2</sub> impacts modeled in ExxonMobil's ambient demonstration, and by the Department in the case of SO<sub>2</sub>, are shown in Table 7. The background concentration, total concentration, and relevant standard for each pollutant and averaging time are also presented for comparison. In each case, the total impact is less than the corresponding standard. Therefore, ExxonMobil will not cause or contribute to a violation of the AAAQS for these pollutants and averaging periods.

**Table 7. Maximum cumulative impacts compared to the AAAQS**

Pollutant	Averaging Period	Modeled Concentration (µg/m <sup>3</sup> )	Background Concentration (µg/m <sup>3</sup> )	Total Impact (µg/m <sup>3</sup> )	AAAQS (µg/m <sup>3</sup> )
NO <sub>2</sub>	Annual	28.1	7.5	35.6	100
	1-hour	130.3 <sup>a</sup>	36.9 <sup>b</sup>	167.2	188
CO	8-hour	1,897.2 <sup>c</sup>	1,333	3,230.2	10,000
	1-hour	2,377.5 <sup>c</sup>	2,171	4,548.5	40,000
PM-10	24-hr	16.7 <sup>c</sup>	49.0 <sup>d</sup>	65.7	150
PM-2.5	Annual	2.6	2.6	5.2	15
	24-hr	17.2	12.7	29.9	35
SO <sub>2</sub>	24-hour	7.0 <sup>c</sup>	23.5	30.5	365
	1-hour	10.5 <sup>e</sup>	75.9	86.4	196

Table Notes

<sup>a</sup> h8h concentration

<sup>b</sup> Highest monthly average background concentration collected during ExxonMobil's monitoring effort at Point Thompson

<sup>c</sup> h2h concentration

<sup>d</sup> Highest background concentration from BPXA's CCP since 2008

<sup>e</sup> h4h concentration

The maximum cumulative annual NO<sub>2</sub>, annual and 24-hour PM-10, and annual and 24-hour PM-2.5 impacts modeled in ExxonMobil’s ambient demonstration is shown in Table 8 for comparison to the respective increment. In each case, the modeled impact is less than the corresponding increment. Therefore, ExxonMobil will not cause or contribute to a violation of the increments for the aforementioned pollutants and averaging times.

**Table 8. Maximum cumulative impacts compared to the increments**

Pollutant	Averaging Period	Modeled Concentration (µg/m <sup>3</sup> )	Increment (µg/m <sup>3</sup> )
NO <sub>2</sub>	Annual	23.7	25
PM-10	Annual	2.4	17
	24-hour	9.1 <sup>a</sup>	30
PM-2.5	Annual	2.0	4
	24-hour	8.7 <sup>a</sup>	9

*Table Notes*

<sup>a</sup> h2h in accordance with Section 163a of the Clean Air Act

## OZONE IMPACTS

As discussed in the Background section, O<sub>3</sub> is a triggered PSD-pollutant for this project. Therefore, ExxonMobil is required to provide a source impact analysis, per 40 CFR 52.21(k).

O<sub>3</sub> is not usually emitted directly into the air, but is instead created in the atmosphere through chemical reactions involving NO<sub>x</sub>, volatile organic compounds (VOC), and sunlight. It is an inherently regional pollutant that is the result of chemical reactions between emissions from many sources over a period of hours or days, and over a large area.

EPA does not have a recommended modeling approach for estimating O<sub>3</sub> impacts from an individual stationary source. The precursor emissions from individual stationary sources are generally within the range of “noise” of regional O<sub>3</sub> models, i.e. the imprecision in predicted concentrations due to the uncertainty in model inputs for emissions, chemistry and meteorology. In practice, it is very rare for states or EPA to require O<sub>3</sub> modeling from a new source review permit applicant.

Point Thomson is located in an area that is designated as unclassifiable for all criteria pollutants, which includes O<sub>3</sub>. ExxonMobil previously noted in support of Construction Permit AQ1201CPT01 that the potential NO<sub>x</sub> and VOC emissions are small compared to those from other North Slope sources and that the emissions from Point Thomson are not substantive enough to lead to a violation of the O<sub>3</sub> AAAQS.<sup>19</sup>

This comparison remains valid for supporting Construction Permit AQ1201CPT02. A tabular presentation of their comparison is therefore reiterated in Table 9. The Department also reiterates that the 8-hour O<sub>3</sub> design concentration, recently measured at Prudhoe Bay Unit (A-Pad), is 34 parts per billion (ppb), which is less than half of the 75 ppb standard. Therefore, since the cumulative NO<sub>x</sub> and VOC emissions within the Prudhoe Bay Unit do not threaten the O<sub>3</sub>

<sup>19</sup> E-mail from Al Trbovich (SLR) to Alan Schuler (Department); RE: *Point Thomson Ozone Impacts* dated 10 January, 2012.

standard, the substantially smaller Point Thomson emissions would be even less likely to violate the O<sub>3</sub> AAAQS.

Table 9 – Comparison of Potential NO<sub>x</sub> and VOC Emissions

Stationary Source	Potential Emissions (tpy)	
	NO <sub>x</sub>	VOC
Point Thomson	162	31
BPXA Central Gas Facility (CGF)	10,968	88
BPXA Central Compressor Plant (CCP)	14,238	84
BPXA Lisburne Production Facility (LPC)	2,241	40
CPAI Central Production Facility 1 (CPF 1)	3,259	154
CPAI Central Production Facility 2 (CPF 2)	2,777	31
CPA Central Production Facility 3 (CPF 3)	2,340	18

ExxonMobil's Table Note: *Potential emissions for Point Thomson are from the PSD permit application submitted to ADEC on 19 July, 2011. Potential Emissions for all other stationary sources are from the Statement of Basis for the Title V operating permits for those facilities.*

## ADDITIONAL IMPACT ANALYSES

Under 40 CFR 52.21(o), PSD applicants must assess the impact from a proposed project and its associated growth on visibility, soils, and vegetation. In the case of the Point Thomson project, the impacts to be assessed include those from the PSD-triggered pollutants NO<sub>2</sub>, O<sub>3</sub>, CO, PM-10, and PM-2.5. ExxonMobil provided an additional impact analysis on pages 17 and 18 of their permit application. The Department is presenting its findings on this analysis below.

The Point Thomson project is located approximately 700 km north of the nearest Class I area, Denali National Park; it is located roughly 1,200 km distant from the Tuxidni National Wildlife Refuge. These distances are typically too large to warrant Federal Land Manager (FLM) involvement. Nevertheless, the Department contacted the FLMs for these areas, the National Park Service (NPS) and the Fish and Wildlife Service (FWS) respectively, to gauge their level of interest given the project scope.<sup>20</sup> Neither FLM provided a reply to the Department's inquiry. As such, ExxonMobil was not required to conduct a Class I impact analysis

### Visibility Impacts

PSD applicants must assess whether the emissions from their stationary source, including associated growth, will impair visibility. Visibility impairment means any humanly perceptible change in visibility, such as visual range, contrast, or coloration, from that which would have existed under natural conditions. Visibility impacts can occur as visible plumes, i.e., *plume blight*, or in a general, area-wide reduction in visibility, also known as *regional haze*. Alaska does not have standards for plume blight, however, the Federal Land Manager provides the desired thresholds for Class I areas. There are no established thresholds for Class II areas.

<sup>20</sup> E-mail from Alan Schuler (Department) to Andrea Stacy (NPS) and Catherine Collins (FWS); *FLM Level of Interest in ExxonMobil Point Thomson PSD Project?*; 9 September, 2010.

ExxonMobil did not conduct a visibility impact assessment of the nearest Class I area, Denali National Park, due to the substantive distance. They did, however, conduct a visibility impact assessment inside the nearby Alaskan National Wildlife Refuge (ANWR) and at its coastal plain.

The typical tool for assessing plume blight is EPA's VISCREEN model. VISCREEN provides results for impacts located both inside and outside a Class I area, with the latter being used in situations where there is an *integral vista*. In situations where there are no integral vistas, applicants only need to use the results for impacts located inside a Class I area. Alaska only has two integral vistas, both of which are associated with the Denali National Park Class I area.

ExxonMobil used VISCREEN version 1.01 to estimate their worst-case plume blight. They appropriately assumed an ozone concentration of 40 parts per billion and a background visual range of 258 km. Since there are no integral vistas near Point Thompson, ExxonMobil was only required to provide the inside impacts.

ExxonMobil conducted a *Level 2* analysis to refine their estimate. Details of the input and output parameters are provided on pages 17 and 18 of their permit application. None of the inside results, given in Tables 1 and 2, exceeded the Class I thresholds. Their analysis therefore shows no adverse visibility impacts.

### **Vegetation and Soil Impacts**

ExxonMobil compared their modeled NO<sub>2</sub>, PM-10, and PM-2.5 impacts to the secondary ambient air quality standards in concurrence with the Department's PSD Vegetation and Soil Assessments Policy of 11 December, 2007; this comparison is given on page 18 of their permit application. While less information is available regarding the effects of air pollutants on soils, protecting vegetative cover will ostensibly help protect soil. Secondary air quality standards are established to protect public welfare which includes harm to crops and vegetation, buildings, and property and ecosystems. As shown in Table 7, the maximum NO<sub>2</sub>, PM-10, and PM-2.5 impacts are below the AAAQS. Therefore, the soil and vegetation near Point Thomson should be protected.

### **Secondary Impacts**

40 CFR 52.21(o)(2) requires PSD applicants to assess the impacts from general commercial, residential, industrial and other growth associated with the source or modification. ExxonMobil does not expect significant changes in these categories. The Department accepts ExxonMobil's assessment.

## **CONCLUSION**

The Department reviewed ExxonMobil's modeling analysis for the Point Thompson project and concludes the following:

1. ExxonMobil's application and supplemental information adequately complies with the PSD *Source Impact Analysis* provisions required under 40 CFR 52.21(k). ExxonMobil has demonstrated that the emissions associated with operating the stationary source, within the restrictions listed in this memorandum, will not cause or contribute to a violation of the annual NO<sub>2</sub>, annual or 24-hour PM-10, and annual or 24-hour PM-2.5 increments listed in 18 AAC 50.020. ExxonMobil has also demonstrated that the

emissions associated with operating the stationary source, within the restrictions listed in this memorandum, will not cause or contribute to a violation of the annual or 1-hour NO<sub>2</sub>, 8-hour or 1-hour CO, 24-hour PM-10, and annual or 24-hour PM-2.5 AAAQS listed in 18 AAC 50.010.

2. ExxonMobil's application and supplemental information adequately complies with the minor permit requirements under 18 AAC 50.540(c)(2). The Department has demonstrated that the SO<sub>2</sub> emissions associated with operating the stationary source, within the restrictions listed in this memorandum, will not cause or contribute to a violation of the annual, 24-hour, 3-hour, or 1-hour SO<sub>2</sub> AAAQS provided in 18 AAC 50.010;
3. ExxonMobil appropriately used the models and methods required under 40 CFR 52.21(l) *Air Quality Models* PSD provisions;
4. ExxonMobil's pre-construction data or project impact analysis adequately satisfies the pre-application air quality analysis required under 40 CFR 52.21(m)(1) *Pre-application Analysis*;
5. ExxonMobil's application adequately satisfies the additional visibility, soils, vegetation, and secondary impact analysis required by the *Additional Impact Analysis* PSD provisions under 40 CFR 52.21(o); and
6. ExxonMobil conducted their modeling analysis in a manner consistent with Guideline, as required under 18 AAC 50.215(b)(1).

The Department has developed conditions in Construction Permit AQ1201CPT02 to ensure ExxonMobil complies with the ambient air quality standards and increments. These conditions are summarized below:

To protect the NO<sub>2</sub>, CO, PM-10, PM-2.5, and SO<sub>2</sub> AAAQS and the NO<sub>2</sub>, PM-10 and PM-2.5 increments, ExxonMobil shall:

1. Establish and maintain the ambient air boundaries as follows:
  - a. Comply with the provisions contained in the February 2013 Public Access Control Plan, or a subsequent written version approved by the Department that only contains editorial revisions.
2. Construct and maintain vertical, uncapped exhaust stacks for all EUs, except
  - a. EUs **7, 8, 14, 15, 16, 17, 105** through **109**, and **237** through **239**; and
  - b. for flapper valve rain covers, or other similar designs, that do not hinder the vertical momentum of the exhaust plume.
3. Construct and maintain EU exhaust stacks with a release point above ground level that equals or exceeds
  - a. 7.6 m for EUs **9** and **10**;
  - b. 22.9 m for EU **37**;

- c. 13.5 m for EUs **47** through **50** and **58** through **61**;
  - d. 27.4 m for EUs **101** through **104**;
  - e. 14.3 m for EUs **105** and **106**;
  - f. 36.6 m for EUs **112** and **113**; and
  - g. 12.2 m for EUs **206A**, **207A**, and **206** through **208**.
4. Prohibit the concurrent operation of the following EU pairs:
    - a. EUs **105** and **106**;
    - b. EUs **201** and **202**;
    - c. EUs **213** and **214**;
    - d. EUs **215** and **216**;
    - e. EUs **217** and **218**;
    - f. EUs **240** and **241**;
    - g. EUs **242** and **243**; and
    - h. EUs **244** and **245**;
  5. Prohibit the concurrent operation of the following EU groups as described:
    - a. No more than four-of-five among EUs **203**, **203A**, **204**, **204A**, and **205**;
    - b. No more than four-of-five among EUs **206**, **206A**, **207**, **207A**, and **208**; and
    - c. Do not operate EUs **105** or **106** in concurrence with EUs **246** or **247**.

To protect the SO<sub>2</sub> AAAQS, ExxonMobil shall:

1. Limit the sulfur content of the liquid fuel to 0.0015 wt% ; and
2. Limit the H<sub>2</sub>S content of the fuel gas to:
  - a. 300 ppmv for the LP flare, EU 113, and all flare pilot and purge regimes; and
  - b. 125 ppmv for all other EUs firing fuel gas, excluding the pilot and purge of the HP flare, EU 112.

To protect the NO<sub>2</sub>, PM-10 and PM-2.5 increments, ExxonMobil shall:

1. Report the date that ExxonMobil “begins actual construction” – as defined in 40 CFR 52.21(b)(11); and
2. Remove or permanently disable EUs **201**, **202**, **242**, **243**, **244**, **245**, and **247** within 24 months of the reported date.

To protect the annual NO<sub>2</sub> and annual SO<sub>2</sub> AAAQS; and the annual NO<sub>2</sub>, annual PM-10 and annual PM-2.5 increments, ExxonMobil shall:

1. Limit EUs **105** and **106**, no more than 8,760 hours-per-year combined;
2. Limit EUs **213** and **214**, no more than 8,760 hours-per-year combined;

3. Limit EUs **215** and **216**, no more than 8,760 hours-per-year combined;
4. Limit EUs **217** and **218**, no more than 8,760 hours-per-year combined;
5. Limit EUs **224** through **227**, no more than 23,370 hours-per-year combined;
6. Limit EUs **237** through **239**, no more than 11,690 hours-per-year combined;
7. Limit EUs **240** and **241**, no more than 8,760 hours-per-year combined;
8. Limit EUs **242** and **243**, no more than 8,760 hours-per-year combined; and
9. Limit EUs **244** and **245**, no more than 8,760 hours-per-year combined.

To protect the short-term NO<sub>2</sub>, SO<sub>2</sub>, PM-10, and PM-2.5 AAAQS; and the short-term PM-10 and PM-2.5 increments, ExxonMobil shall:

1. Limit EUs **107** through **109** to no more than 4 hours-per-day each; and
2. Limit EUs **110** and **111** to no more than 12 hours-per-day each.

To protect the annual and 1-hour NO<sub>2</sub> AAAQS, ExxonMobil shall:

1. Limit EUs **36**, and **38** through **46** to no more than 1,080 hours per year each; and
2. Limit EU **37** to no more than 500 hours per year.

To protect the 1-hour NO<sub>2</sub> AAAQS, ExxonMobil shall:

1. Prohibit the concurrent operation of more than two-of-three EUs **237** through **239**;
2. Prohibit the concurrent operation of any of EUs **107** through **109**; and
3. Prohibit the concurrent operation of EUs **110** and **111**.

To protect the annual NO<sub>2</sub> increment, ExxonMobil shall limit the operation of EUs 103 and 104, in SoLoNOx mode firing ULSD, to no more than 2,000 hours per year combined.